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Your ref. Docket No. 52-006
Our ref DCP/NRC1553

March 13, 2003

SUBJECT: Transmittal of Westinghouse Responses to US NRC Requests for Additional Information on the AP1000 Application for Design Certification

This letter transmits the Westinghouse revised responses to NRC Requests for Additional Information (RAI) regarding our application for Design Certification of the AP1000 Standard Plant. A list of the RAI responses that are transmitted with this letter is provided in Attachment 1. Attachment 2 provides the RAI responses.

Please contact me if you have questions regarding this submittal.

Very truly yours,

M. M. Corletti
Passive Plant Projects & Development
AP600 & AP1000 Projects

/Attachments

1. Table 1, "List of Westinghouse's Responses to RAIs Transmitted in DCP/NRC1553"
2. Westinghouse Non-Proprietary Response to US Nuclear Regulatory Commission Requests for Additional Information dated March 2003

DCP/NRC1553

March 13, 2003

Attachment 1

ATTACHMENT 1

Table 1 "List of Westinghouse's Responses to RAIs Transmitted in DCP/NRC1553"	
210.021 Rev. 1	420.005 Rev. 1
210.023 Rev. 1	420.012 Rev. 1
220.001 Rev. 1	420.022 Rev. 1
220.005 Rev. 1	440.048 Rev. 1
230.018 Rev. 2	440.049 Rev. 1
250.003 Rev. 1	440.052 Rev. 1
251.004 Rev. 1	440.076 Rev. 1
251.029 Rev. 1	440.089 Rev. 1
252.006 Rev. 1	440.099 Rev. 1
261.010 Rev. 1	451.008 Rev. 0
281.001 Rev. 1	460.007 Rev. 1
410.005, Rev. 1	620.001 Rev. 1
410.016, Rev. 1	620.018 Rev. 1
410.018, Rev. 1	Teleconference Summary

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

Telephone Conference Call Summary

On January 21, 2003, Westinghouse and NRC held a telephone conference call to discuss issues associated with the structural design portion of the AP1000. The following discussion summarizes our responses to the issues raised regarding in the telephone conference call that was summarized in the NRC Memorandum from Lawrence J. Burkhart to Marsha Gamberoni dated February 6, 2003. Specifically, this memorandum requested that Westinghouse inform the NRC staff of its intentions regarding how Westinghouse plans to address the issues of (1) peer review of its AP1000 design models and (2) stiffness reduction of shear wall models.

Question: (NRC Letter of January 21, 2003, Telephone Conference Call Summary)

Peer Review

Given that the AP1000 NI model is very complex and was developed through the collaborative efforts of consultants from Switzerland, Spain, Italy, Japan and two entities in the United States, The NRC staff is concerned about the process used by Westinghouse to ensure the adequacy of the structural model for use in the design of structures, systems and components (SSCs). The requirement regarding reasonable assurance of the quality of the design of SSCs stems from general design criterion (GDC) No. 1, "Quality Standards and Records," of Title 10 of the *Code of Federal Regulations* (10CFR) Part 50. The importance of ensuring the appropriateness of analytical assumptions made (including the size and type of finite elements used to develop the dynamic model) is emphasized in the design control criteria of Appendix A to Part 50 which states that "[m]easures shall be established for the identification and control of design interfaces and for coordination among participating design organizations. These measures shall include the establishment of procedures among participating design organizations for the review, approval, release, distribution, and revision of documents involving design interfaces. The design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of a suitable testing program. The verifying or checking process should be performed by individuals or groups other than those who performed the original design, but who may be from the same design organization." To address this issue, the NRC staff highlighted the need for a peer review of the NI design model during the November 2002 meeting and reiterated the same position at the January 21, 2003, telephone conference call. The NRC staff believes that a peer review of the complex NI model of the AP1000 is especially important in the light of the fact that Westinghouse did not consider the stiffness reduction of the shear walls. Westinghouse agreed to inform the NRC staff of its intentions to address the issues of (1) peer review of its AP1000 design models and (2) stiffness reduction of shear wall models.

NRC Tests on Concrete Shear Walls:

Seismic tests on scaled shear wall structures were conducted by the Los Alamos National Laboratory under the sponsorship of NRC's Office of Nuclear Regulatory Research and the shear walls exhibited natural frequencies that were lower than those calculated by the gross section properties of uncracked concrete sections even at relatively low levels of shaking, far

less than the SSE level of vibration. This was a surprise to many, including the Review Panel members. After a lot of peer review and detailed investigation by academicians, a paper written by Prof. Sozen (a member of the Review Panel) explained the reasons and made some recommendations for capturing the stiffness of shear walls in modeling their behavior in a seismic motion. The reference to this paper is: J.P. Moehle, P. Monteiro, H.T. Tang, and M.A. Sozen, "Effects of Cracking and Age on Stiffness of Reinforced Concrete Walls Resisting In-Plane Shear," Proceedings of the Fourth Symposium on Nuclear Power Plant Structures, Equipment, and Piping, North Carolina State University, Raleigh, N.C., December 1992, pp. 3.1-3.13. This paper recommends that the shear deformation part should be evaluated using gross uncracked area values, but the flexural properties should be based on cracked section properties.

The most recent guidance on the effective stiffness of reinforced concrete members is given in the proposed (Draft) ASCE Standard, "Seismic Design Criteria For Structures, Systems And Components In Nuclear Facilities" in Section 3.4. Provisions of this Section are excerpted below:

3.4 Modeling and Input Parameters

3.4.1 Effective Stiffness of Reinforced Concrete Members

In lieu of a detailed stiffness calculation, the effective stiffness of reinforced concrete members provided in Table 3.4-1 shall be used in linear elastic static or dynamic analysis. When finite element methods are used, the element stiffness shall be modified using the effective stiffness factor for the dominant response parameter.

Table 3.4-1 Effective Stiffness of Reinforced Concrete Members

Member	Flexural Rigidity	Shear Rigidity	Axial Rigidity
Beams – nonprestressed	$0.5E_cI_g$	G_cA_w	
Beams – prestressed	E_cI_g	G_cA_w	
Columns in compression	$0.7E_cI_g$	G_cA_w	E_cA_g
Columns in tension	$0.5E_cI_g$	G_cA_w	E_sA_s
Walls and Diaphrams – uncracked , $f_b<f_{cr}$, $V<V_c$	$0.8E_cI_g$	$0.8G_cA_w$	E_cA_g
Walls and Diaphrams – cracked, $f_b>f_{cr}$, $V>V_c$	$0.5E_cI_g$	$0.5G_cA_w$	E_cA_g

E_c = concrete compressive modulus	A_w = web area	f_{cr} = cracking stress
G_c = concrete shear modulus = 0 4E_c	A_g = gross area of the concrete section	V = wall shear
E_s = steel modulus	A_s = gross area of the reinforcing steel	V_c = nominal concrete shear capacity
I_g = gross moment of inertia	f_b = bending stress	

Effective Stiffness of Reinforced Concrete Members

Table 3.4-1 is derived from FEMA 356, Table 6-5. For additional information on effective stiffness, consult FEMA 274, Section C6.4.1.2.

Consideration of Realistic Stiffness Properties of Shear walls:

Using the recommendation in the reference in Sozen's paper, the cracked moment of inertia of a shear wall section is 63% of the gross value.

Recommendation:

Westinghouse should use the criteria in the FEMA documents. These criteria are based on substantial new research.

Westinghouse Response:

Peer review of AP1000 design models

Westinghouse has performed the structural design of the AP1000 in accordance with the applicable portions of the Code of Federal Regulations including 10 CFR Part 50 Appendix B "Quality Assurance Requirements for Nuclear Power Plants and Fuel Reprocessing Plants." As discussed with the NRC, there is not a regulatory requirement for Westinghouse to conduct a peer review of the AP000 structural design. The Westinghouse design procedures have been followed, and the fidelity of the AP1000 structural design is acceptable. The following discussion provides our response on how this issue should be resolved.

The analytical models of the nuclear island were prepared by a number of different organizations under Westinghouse direction. Westinghouse defined the interfaces between these models and combined the models together in various analyses.

- Axisymmetric, finite element shell and stick models were created by Westinghouse for the shield building roof following the approach used by Ansaldo in preparing the AP600 models previously reviewed by NRC. These AP1000 models were verified by Ansaldo.

- Finite element shell and stick models of the auxiliary building were created by NOK and verified by Westinghouse. These models include the shield building roof models described in the previous paragraph. Westinghouse defined the interface with the containment internal structures at the 69' 6" radius of the inside face of the shield building cylinder from the bottom of the basemat at elevation 60' 6" up to grade at elevation 100'. Westinghouse worked closely with NOK in defining the analytical assumptions (including the size and type of finite elements used to develop the dynamic model). The model was established as a solid model in ANSYS to permit subsequent finite element generation with refinement appropriate to the scope of the analyses. In this approach, the solid model includes areas representing each different design configuration of the structure (walls, floors, thickness, floor loads, openings, etc.). This solid model is then used to generate finite element models. NOK generated and Westinghouse verified the finite element model used for the modal analyses. Westinghouse generated and verified the more refined finite element model used in the equivalent static analyses to provide member forces in each of the walls and floor slabs.

- Finite element shell and stick models of the containment internal structures and the basemat below the containment vessel inside the shield building were created and verified by Ansaldo and reviewed by Westinghouse. Walls and floors were modeled by shell elements following the approach used by Ansaldo for the AP600 analyses previously reviewed by NRC. The basemat was modeled using solid elements.

- Finite element axisymmetric and stick models of the containment vessel were created and verified by CBI and reviewed by Westinghouse. These followed the approach used by CBI for the AP600 analyses previously reviewed by NRC.

The modeling approach is similar to that used for the AP600 and was performed in most cases by personnel who had been involved in AP600 analyses. The primary change is the replacement of the BSAP computer program by ANSYS and the use of the ANSYS solid model capability in developing the finite element models.

Finite element models and analyses are documented as engineering calculations in accordance with Westinghouse quality assurance procedures. This includes verification by an independent person. Typical results are compared during this documentation process against those previously reviewed for the AP600. In addition to the formal quality assurance procedures followed by Westinghouse's partners, Westinghouse interacts with the partner during the work and reviews the final documentation. This review is extensive in the early stages of work with a partner and is reduced as Westinghouse establishes confidence in their capability.

A second level of model review occurs as the member forces from the detailed analyses are used in the design of the critical structural elements. In most cases the design of reinforcement in the structural element is performed by individuals who were not responsible for either the global analyses or for their verification. Critical sections are being designed through the collaborative efforts of Westinghouse and its partners including personnel from Ansaldo in Italy, Initec in Spain and Obayashi in Japan following Westinghouse quality assurance procedures. The designer of the critical section is responsible for reviewing the results of the global analysis in his assigned area and for determining that the results are appropriate for his use. Where the review shows areas in which the model could be improved, the results are evaluated by the designer and Westinghouse together to confirm that the models are appropriate for use and the results are adjusted if necessary in the design calculation for the individual wall or floor. Such cases are documented and will be considered for incorporation in a revised model if it is necessary to rerun any of the analyses. Westinghouse considers this process to provide an appropriate level of design assurance.

Recognizing the concern of the NRC staff, Dr William LaPay will perform an independent peer review of the finite element structural models of the auxiliary building. He will concentrate on the areas where the methodology has changed from the AP600, namely the creation of the ANSYS solid model and its use in generation of the finite element models. He has provided technical support to the AP600 project, including similar roles working closely with Quality Assurance and technical reviews acting as the technical review chairman of established peer review panels. Although he is already providing support to the AP1000, he has not been involved in the development of the structural models that he will be requested to assess, and is therefore, considered independent. He is a recognized technical expert in the area of commercial nuclear power plants. This review will be initiated by May 1, 2003.

Stiffness reduction of shear wall models

Westinghouse accepts the NRC staff recommendation to adopt the criteria in the FEMA documents for the stiffness of reinforced concrete shear wall structures. The reduction in stiffness will be included in existing analyses by changing the broadening of the floor response spectra. It will be considered directly in any new structural analyses.

FEMA 356, Table 6-5 recommends a flexural rigidity of $0.8E_c I_g$, a shear rigidity of $0.4E_c A_w$, and an axial rigidity of $E_c A_g$ for walls that are generally uncracked. The draft ASCE standard replaces the shear rigidity of $0.4E_c A_w$ by $0.8\ G_c A_w$ and defines G_c as $0.4\ E_c$. The existing AP1000 analyses use gross uncracked properties, i.e. a flexural rigidity of $E_c I_g$, a shear rigidity of $G_c A_w$ ($= 0.43E_c A_w$), and an axial rigidity of $E_c A_g$.

Westinghouse agrees that gross concrete properties may be overly stiff for the dynamic analyses. Westinghouse presented results of non-linear analyses to assess the effect of cracking during the meeting with NRC staff in November, 2002. These analyses showed a reduction in frequency of about 7% due to cracking with a reduction in the peak acceleration. The non-linear analyses were performed on a simplified stick model using methods described in NUREG/CR-6241, "Technical Guidelines for A Seismic Design of Nuclear Power Plants (Translation of JEAG 4601-1987)". These methods are supported by seismic testing in Japan.

Structural analyses of the AP1000 have been completed for the hard rock site. These analyses will not be revised since the dominant building structural frequencies are already at or near the peak of the ground response spectrum, and the study of the effect of cracking has shown a reduction of frequency of about 7% with a lower peak acceleration in structural response. However, the floor response spectra specified for equipment design will be revised by broadening the raw spectra by +10% and –20% instead of the ±15% currently described in DCD subsection 3.7.2.5. DCD subsection 3.7.2.5 and Figure 3.7.2-15 will be revised accordingly.

If the dynamic analyses are rerun, reductions in stiffness will be considered for reinforced concrete elements of the auxiliary building. The stiffness reductions will be considered in the auxiliary and shield building analyses using an elastic modulus of $0.8\ E_c$ and broadening the resulting spectra by ±15%. No reduction will be considered where the principal structures are structural modules such as inside containment and in the fuel pit area. As described in DCD subsection 3.8.3.4, shear stresses in the structural modules due to seismic loads are low. Also the behavior studies show less degradation of stiffness for the concrete filled steel plate modules than for reinforced concrete.

DCD Revision:

Revise DCD subsection 3.7.2.5 as follows:

The spectral peaks associated with the structural frequencies are broadened by **+10% and –20% for the auxiliary and shield buildings and by** ±15 percent **for the containment vessel and containment internal structures** to account for the variation in the structural frequencies, due to the uncertainties in parameters such as material and mass properties of the structure and soil, damping values, seismic analysis technique, and the seismic modeling technique. Figure 3.7.2-14 shows the broadening procedure used to generate the design floor response spectra.

Revise broadened spectra in Figure 3.7.2-15 to show +10% and –20% broadening.

PRA Revision:

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 210.021 (Response Revision 1)

Question:

Reference, Volume 6, Section 3.9.5.3, Pg. 3.9-80:

For those components designated ASME III Class CS core support structures, please provide a specific commitment that they are designed, fabricated, and examined in accordance with the requirements of ASME III, Subsection NG, Core Support Structures. Also for Class CS core support structures, provide a statement that the design documentation for these components includes a certified Design Specification, and a certified Design Report conforming to the requirements of ASME III, Subsection NCA.

For those RPV internals components not designated ASME III Class CS core support structures, please identify the design basis used for design, construction, and examination.

Follow-On Comment:

The staff believes that a clarification regarding the design requirements used for the energy-absorbing, elastic-plastic devices in the secondary core support structure is desirable.

Westinghouse Response (Revision 1):

The components designated as ASME III Class CS core support structures will be designed, fabricated and examined in accordance with the requirements of ASME III, Subsection NG for Core Support Structures. The design documentation for these Class CS core support structures will include a certified Design Specification and a certified Design Report conforming to the requirements of ASME III, Subsection NCA.

Those RPV internals components not designated ASME III Class CS core support structures **are designated as RPV Internal Structures per** ASME III, Subsection NG. **Internal structures are defined as all structures within the reactor pressure vessel other than core support structures, fuel and blanket assemblies, control assemblies and instrumentation. As provided in paragraph NG-1122 in the ASME III, Subsection NG requirements, Westinghouse, as Certificate Holder, defines the design requirements for these components.**

The **AP1000** Core Shroud assembly is similar to that in current Combustion Engineering plants and **the secondary core support structure is similar to that in current Westinghouse plants. Both are** designated as Internals Structures per ASME III, Subsection NG.

The requirement imposed by Westinghouse for design of the elastic-plastic devices in the secondary core support structure is to use elastic plastic data based upon commonly accepted elastic-plastic stress-strain material curves. The curves utilized are based on Westinghouse developed data which have been used in the design of similar secondary core support structures in currently operating Westinghouse plants.

Design Control Document (DCD) Revision:

From DCD **Revision 3,** Page 3.9-78a:

3.9.5.3 Design Bases

The reactor vessel internals components designated as ASME III Class CS core support structures are designed, fabricated and examined in accordance with the requirements of ASME III, Subsection NG for Core Support Structures. The design documentation for these Class CS core support structures include a certified Design Specification and a certified Design Report conforming to the requirements of ASME III,Subsection NCA.

The basis used for design, construction, and examination for those reactor vessel internals components not designated ASME III Class CS core support structures are **defined by Westinghouse as provided in** the ASME**Code**, Subsection NG.

The scope of the stress analysis requires many different techniques and methods, both static and dynamic. The analysis performed depends on the mode of operation.

PRA Revision:

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 210.023 (Response Revision 1)

Question:

Reference, Volume 6, Table 3.9-14:

The component terms "upper barrel" and "upper package" are listed in this table for maximum allowable deflections. The physical locations and functions of these components are not clear from the arrangement drawings and discussions provided elsewhere in the DCD. Please provide additional arrangement details, e.g., in Figure 3.9-8, Reactor Internals Interface Arrangement, for clarification.

Follow-On Comments:

(A) On the third line under the heading Upper Core Barrel, the radial outward (non-uniform) allowable deflection is not clearly defined, because it is stated as a percentage of annulus area, which is not a linear deflection (as required by the column heading in the table).

(B) (Editorial) The first line under the heading Upper Core Barrel, should read, 'Radial inward,' instead of 'Radial outward.'

(C) (Editorial) On the last line of the table, Rod cluster guide tubes, please include the direction, i.e., lateral, of the allowable deflection.

Westinghouse Response (Revision 1):

The terms "upper barrel" and "upper package" describe various regions where displacement criteria are imposed on the design of the reactor internals (core support structures). The "upper barrel" is the core barrel above the upper core plate. The displacement of the "upper package" refers to the relative vertical movement between the upper core plate and upper support plate. The displacement criteria in Table 3.9-14 are in addition to the stress criterion that is identified in subsection NG of section III of the ASME Boiler and Pressure Vessel Code. The upper barrel inward and outward displacement limitations are further described in DCD section 3.9.5.3.2. The upper package deflection limitation is further described in the same section.

Table 3.9-14 will be modified to more clearly identify that the radial deflections are associated with the upper core barrel, to provide a specific definition of the "upper package" deflection, **to change the first line to 'Radial inward (uniform)', to indicate the direction of the guide tube deflection, and to make the non-uniform radial outward deflection limit a note to the table.**

The upper core barrel and upper core plate will be identified in DCD Figure 3.9-8.

Design Control Document (DCD) Revision:

From DCD **Revision 3,** page 3.9-119:

Table 3.9-14

MAXIMUM DEFLECTIONS ALLOWED FOR REACTOR INTERNAL SUPPORT STRUCTURES

Component	Allowable Deflections (in.)
Upper Core Barrel	
Radial inward **(uniform)**	.....4.1
Radial outward (uniform) (1)	.....1.0
Upper package – relative vertical motion between upper core plate and upper support plate	.....0.20
Rod cluster guide tubes – **radial toward the reactor vessel outlet**	.....1.00

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(1) Non-uniform radial outward deflections are limited such that >90% of the annulus area is maintained

From DCD page 3.9-177, Figure 3.9-8:

See attached figures for changes.

PRA Revision:

None

Figure From AP1000 DCD Revision 2

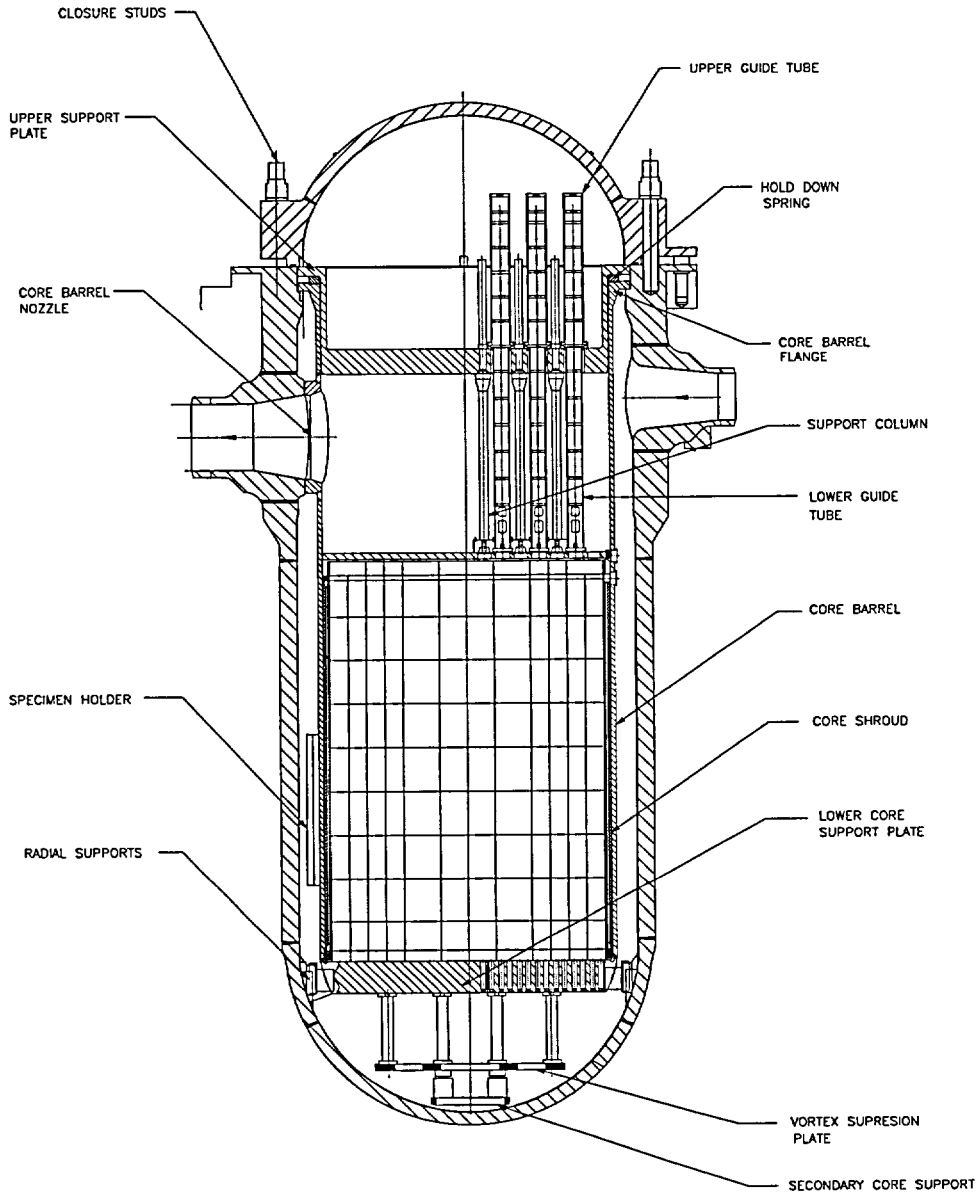


Figure 3.9-8

Reactor Internals Interface Arrangement

Revised Figure

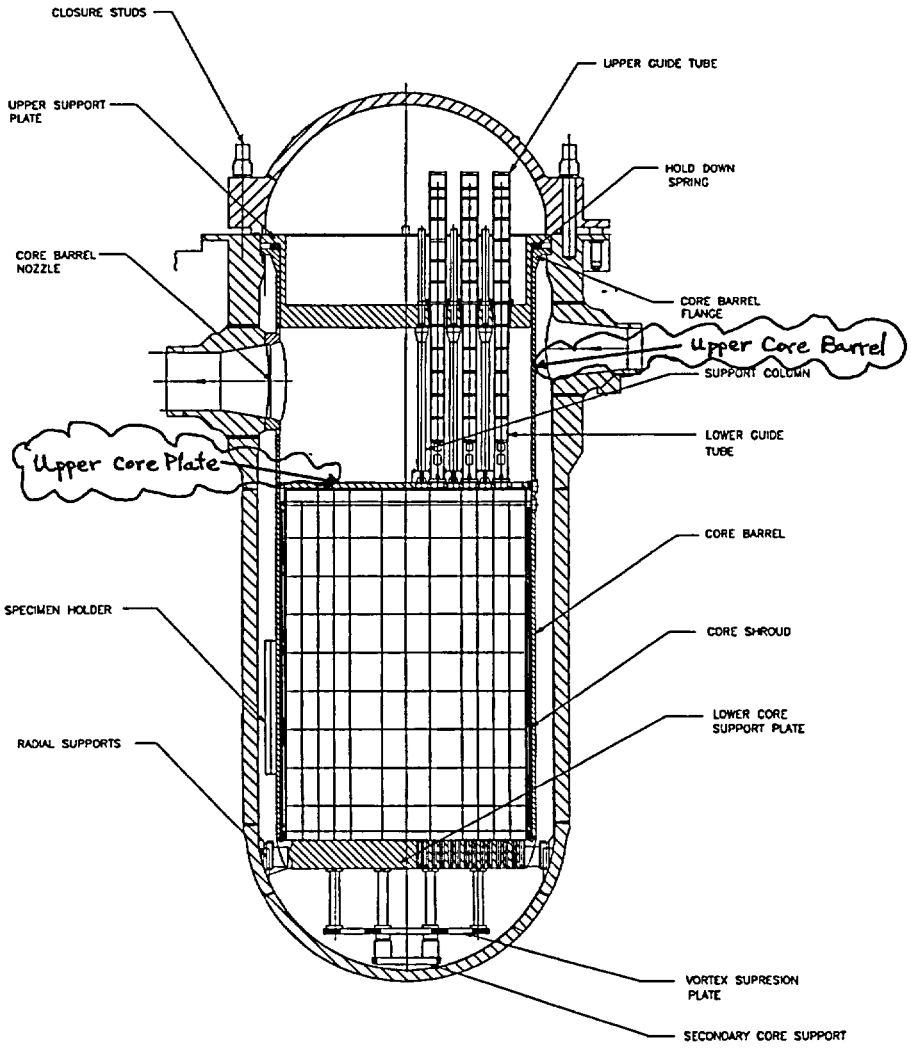


Figure 3.9-8

Reactor Internals Interface Arrangement

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 220.001 (Response Revision 1)

Question:

In order to verify the design adequacy of AP600, Westinghouse conducted various performance tests for unique AP600 systems. The outcome of these tests was used to define the resulting loads for the design of seismic Category I structures (containment vessel, containment internal structures, and coupled shield building and auxiliary building). In the AP1000 DCD Section 1.5, "Requirements for Further Technical Information," Westinghouse states that the AP600 test results are also applicable to the AP1000, and cites Reference 25 [WCAP-15613, "AP1000 PIRT and Scaling Assessment," (Proprietary), WCAP-15706 (Nonproprietary), dated March 2001] for documentation of its evaluation to support this conclusion. DCD Table 1.5-1 provides a list of AP600 tests and AP1000 evaluations with references to test and evaluation documentation. However, the details of how design loads for structural evaluation are not evident from these reports. The design of AP1000 containment structure, the containment internal structures and other Category I structures (i.e., shield building, auxiliary building, containment air baffle, cable tray supports, and HVAC supports) needs to consider the effects of loads from thermal striping of the exterior surfaces of the taller AP1000 containment, the loads from the higher mass and energy release for AP1000 containment internal structures, and the loads that are applicable to the other Category I structures for AP1000. Therefore, please provide a detailed technical basis for the loads for the three types of structures discussed below.

A. loadings on the AP1000 Containment, due to thermal striping.

B. loadings on the AP1000 containment internal structures.

C. loadings on other AP1000 Category I structures (i.e., shield building, auxiliary building, containment air baffle, cable tray supports, and HVAC supports).

Westinghouse Response (Revision 1):

AP600 test results were used to evaluate design loads for the AP1000 structures as described and justified below:

- the AP600 Passive Containment Cooling System water distribution tests described in References 8, 9 and 10 listed in Table 1.5-1 were used to define wet and dry regions around the containment vessel to evaluate the potential for buckling of the vessel due to an asymmetric thermal distribution.

- the AP600 Automatic Depressurization System hydraulic tests described in References 3 and 4 listed in Table 1.5-1 were used to define design loads on the AP1000 in-containment refueling water storage tank constructed integrally with the containment internal structures.

- the AP600 wind tunnel tests described in References 11 through Reference 15 listed in Table 1.5-1 were used to define design loads on the AP1000 containment vessel and containment air baffle.

No other AP600 tests were used to define design loads on AP1000 structures.

A. Passive Containment Cooling System Water Distribution Test

The AP600 water distribution tests were used to define wet and dry regions around the containment vessel to evaluate the potential for buckling of the vessel due to an asymmetric thermal distribution. The tests showed that there may be wet and dry sections of the containment vessel. Typically the tests showed a number of vertical dry strips surrounded by wet areas. Review of the test data indicated that the wet areas covered about 70 percent of the surface and that the dry areas could have a maximum width of about 15 inches. In the safety analyses temperatures of the vessel were calculated separately for the wet and dry regions with no consideration of heat conduction from one to the other. These analyses showed a maximum difference in temperature between wet and dry regions of 68°F. Structural analyses were performed for the AP600 to investigate the effect of these temperature variations on the vessel stresses. The temperature difference was conservatively specified as 80°F. The containment vessel cylindrical wall was evaluated assuming that the metal temperature was constant on a given azimuth and that the circumferential temperature was defined by 15 inch wide dry strips at a temperature of 280 °F, alternating with 34 inch wide wet strips at a temperature of 200 °F.

The AP1000 containment vessel head geometry is the same as that of the AP600 so the selection of wet and dry strips for the AP600 evaluation is directly applicable to AP1000. The safety analyses of the AP1000 containment show a maximum difference in temperature between wet and dry regions of less than 70°F. This temperature difference is less than the 80°F difference evaluated for the AP600. The AP1000 containment vessel design temperature is 300°F, which is 20°F higher than for the AP600. However, the absolute magnitude of the temperature is not significant since it is the difference in temperatures that leads to the thermal stresses in the buckling evaluation.

The AP600 containment vessel evaluation for asymmetric temperature distribution was found acceptable as stated in the AP600 FSER. The evaluation is documented in Westinghouse's letter of July 02, 1993 (ET-NRC-93-3916) which was provided in response to NRC's request for additional information dated 4/2/93. The conclusion of the evaluation states:

> "The containment vessel was evaluated for temperature variations around the vessel that were conservatively postulated based on a review of the water distribution tests and other safety analyses. Shell stresses due to the thermal loads were conservatively evaluated and demonstrated large margin against buckling. The evaluation has demonstrated that such temperature variations are not significant to the design of the containment vessel."

The thickness of the AP1000 containment vessel head is 1.625 inches and is the same as the AP600. The thickness of the AP1000 containment vessel cylinder is 1.75 inches compared to

the 1.625 inch thickness of the AP600. This increase in thickness will increase the margin against buckling. **The temperature differences between wet and dry regions of the AP1000 are bounded by the temperature differences evaluated for the AP600.** Thus, the conclusions of the AP600 evaluation are also applicable to the AP1000 and the temperature variations are not significant to the design of the containment vessel.

B. Automatic Depressurization System Hydraulic Tests

The AP600 Automatic Depressurization System hydraulic tests were used to define design loads on the AP1000 in-containment refueling water storage tank constructed integrally with the containment internal structures. Two pressure time histories, characterized by different shapes and frequency content, were selected from the tests as representative of the sparger discharge pressures.

- A pressure time history representing two phase blowdown with high mass flow rates (above 650 lbs/sec) and quality resulting in significant frequency content below 50 Hertz and pressure peaks at the test tank walls comparable to the highest values measured during the two phase blowdown tests. **The limiting pressure time history corresponds to ADS operation beyond 400 seconds after ADS initiation, when the RCS pressure is reduced, and significant two-phase flow is discharged through the spargers.**

- A pressure time history representing **inadvertent** opening of the second or third stage of ADS at full pressure. This is characterized by pure steam flow.

The time histories from these tests are also applicable to the AP1000 since they occur at the beginning of the transient, and the automatic depressurization system and the initial conditions are the same for the two plant designs. The design of the automatic depressurization system valves that discharge into the in-containment refueling water storage tank are the same for both plants, including the key features controlling the blowdown, such as valve opening times, flow areas, flow rates and fluid conditions. The design of the sparger and the in-containment refueling water storage tank are also the same for both plants.

The attached Figure 220.001R1-1 illustrates the AP600 and AP1000 behavior during the limiting pressure-time history with two-phase flow discussed above. As can be seen, the ADS two-phase blowdown for the AP600 and AP1000 are similar, and the ADS flow rates during the time of interest (at lower RCS pressures beyond 400 seconds) are below the bounding value of 650 lbm/sec that was measured in the ADS test facility. Therefore, for both the AP600 and AP1000, the bounding pressure-time histories used to determine the loads in the IRWST are conservative.

The response of the AP1000 in-containment refueling water storage tank to these time history forcing functions is addressed in Westinghouse's response to RAI 220.009.

C. Passive Containment Cooling System Wind Tunnel Tests

The AP600 wind tunnel tests were used to define design loads on the AP1000 containment vessel and containment air baffle.

The containment vessel is surrounded by the shield building and is only subjected to wind loading in the upper annulus. The containment air baffle is located within the annulus between the containment vessel and the shield building. It interfaces with the passive containment cooling system and separates downward flowing air entering at the air intake openings at the top of the cylinder portion of the shield building from upward flowing air that cools the containment vessel and flows out of the discharge diffuser.

The wind loading for seismic Category I structures is in accordance with American Society of Civil Engineers, "Minimum Design Loads for Buildings and Other Structures," ASCE 7-98. The analytical procedures given in ASCE 7-98, Section 6.5 do not apply to the differential pressures within the annulus and on the containment air baffle since this structure has unusual, irregular geometric shapes, and is subject to channeling effects. ASCE 7-98 permits wind tunnel tests in lieu of analytical procedures for such a configuration.

Westinghouse performed wind tunnel tests for the AP600 configuration to confirm functionality of the passive air-cooling under wind conditions. As noted in subsection 3.3.2.4 of the AP1000 Design Control Document, the pressure coefficients from these tests are used to define wind and tornado loadings on the containment vessel and containment cooling air baffle.

The AP600 wind tunnel tests developed pressure coefficients (C_P) for the containment air baffle area. The envelope C_P values reflect the winds from different directions (azimuths). To obtain the pressure loading, the dynamic pressure at roof height is multiplied by the pressure coefficient at the different levels of the containment air baffle.

The AP1000 shield building and containment vessel are 25' 6" higher than the AP600. The containment air baffle is similar to the AP600 plant except that it is also 25' 6" longer. The AP1000 air intakes are 12 feet wide by 6 feet 6 inches high and have approximately the same flow area as the 16 feet wide by 5 feet high AP600 air intakes. The discharge for both plants is 32 feet in diameter. The air intakes and discharge are 25' 6" higher but are situated around the shield building at the same radius as the AP600 plant. The pressure coefficients will not change since the basic shape (geometric design) and channeling effects are similar to the AP600 plant. Thus, it is concluded that the pressure coefficients (C_P) obtained from the wind tunnel test data for the AP600 plant are also applicable to the AP1000 plant.

The differential wind pressure loads on the airbaffle are based on the "Test Data Upper Bound" of Figure 19 of the Phase IV Wind Tunnel report (WCAP-14068, Phase IVa Wind Tunnel Testing for the Westinghouse AP600 Reactor, G.R. Lythe and D. Surry, Boundary Layer Wind Tunnel Laboratory, The University of Western Ontario, BLWT-SS4-1994, 1994.). This figure shows a maximum differential pressure coefficient of 1.08 opposite the center of the air intakes with a linear decrease in pressure below this elevation to a coefficient of 0.33 at the bottom of

the air baffle. For the AP600 plant, the portion of the air baffle between elevation 243.5' and elevation 142' was designed based on a linear pressure distribution between these elevations. The pressures may be either positive or negative with pressures on adjacent panels being in the same direction. For the AP1000 plant, the same procedure is followed with a linear pressure distribution between elevation 269' (25' 6" higher for the AP1000 plant) and bottom elevation 142' (same as AP600). The pressure coefficient at the bottom of the air baffle is dependent on the pressure coefficients at the intake and the discharge and is not affected by the increase in height. The differential pressure coefficients for the air baffle and the applicable elevation of these coefficients for the AP600 and AP1000 plants are given in Table 220.001-1.

Table 220.001-1 also shows the differential pressures for the tornado that controls the design of the air baffle. The differential pressure coefficients are calculated relative to the dynamic wind pressure at the top of the shield building. The increase in height of the shield building increases the wind pressure for the design wind by less than 3 percent. It does not affect the tornado wind pressure since the wind speed in the tornado does not vary with height. The tornado dynamic pressure is 116 psf. Thus, the maximum differential pressure is 1.08 x 116 = 125 psf (0.87 psi) at the air intakes.

Table 220.001-1

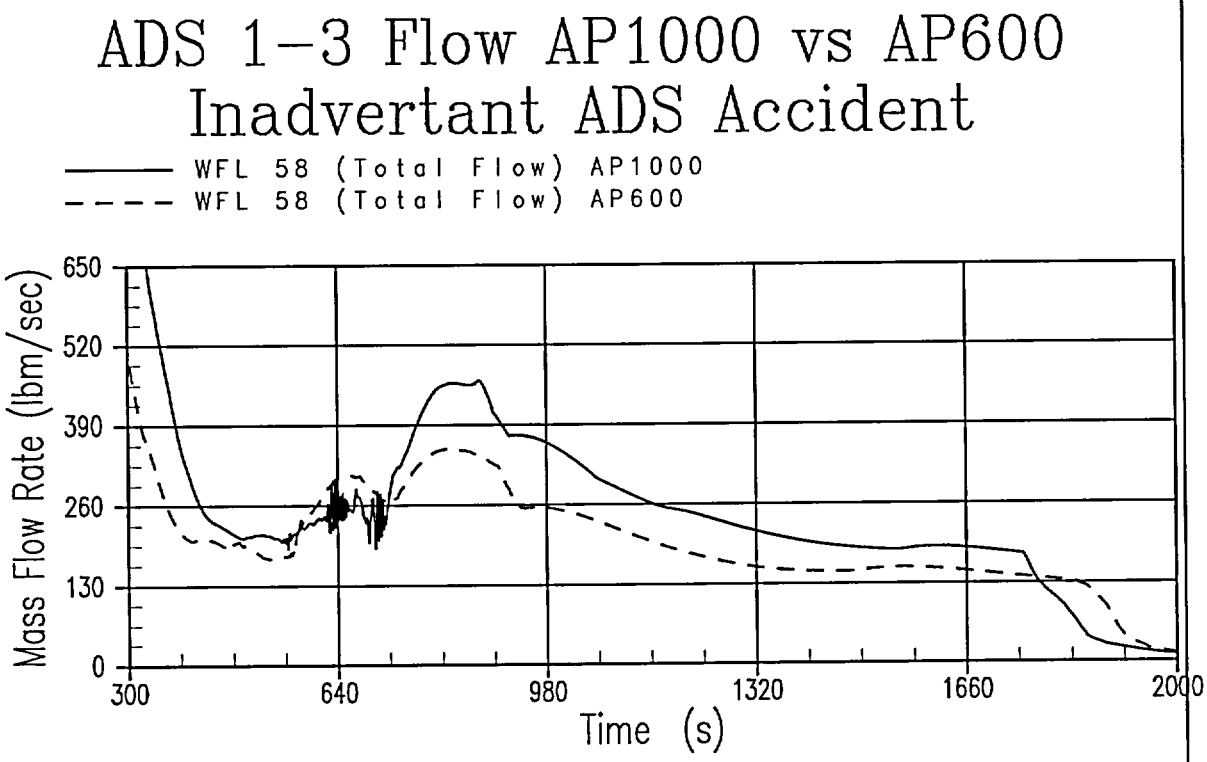
Plant	Description	Center of Air Intakes	Bottom of air baffle (Elevation 142')
AP600	Differential pressure coefficient (Figure 19)	1.08 (Elevation 243.5')	0.33
AP1000	Differential pressure coefficient (based on Figure 19)	1.08 (Elevation 269')	0.33
AP600	Tornado differential pressure (psi)	0.87	0.27
AP1000	Tornado differential pressure (psi)	0.87	0.27

Design Control Document (DCD) Revision:

None

PRA Revision:

None


ADS 1-3 Flow AP1000 vs AP600
Inadvertant ADS Accident
WFL 58 (Total Flow) AP1000
WFL 58 (Total Flow) AP600
Mass Flow Rate (lbm/sec)
650
520
390
260
130
0
300
640
980
1320
1660
2000
Time (s)

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 220.005 (Response Revision 1)

Question:

In the AP1000 DCD Section 3.8.2 "Steel Containment," Subsection 3.8.2.6, "Materials, Quality Control, and Special Construction Techniques" (Page 3.8-15), Westinghouse states that "The basic material is SA738, Grade B, plate. This material has been selected to satisfy the lowest service metal temperature requirement of -15°F. This temperature is established by analysis for the portion of the vessel exposed to the environment when the minimum ambient air temperature is -40°F. Impact requirements are as specified in NE-2000." The staff notes that for AP600 the lowest service metal temperature requirement is -40°F. Westinghouse is requested to provide the details of the analysis conducted for AP1000 that justifies the change in the minimum service temperature, from -40°F for AP600 to -15°F for AP1000, and also to indicate whether SA738, Grade B meets the impact requirements of NE-2000 if the minimum service temperature requirement is -40°F.

Westinghouse Response:

The minimum environment temperature is specified in Table 2-1 to be –40 ° F. For operating conditions, the inside containment atmosphere temperature can be as low as 50 ° F. Natural convection and radiation heat transfer is assumed along the inside and outside containment shell surface. Air enters the passive containment cooling system air inlets at –40 ° F and is heated as it contacts the outer containment shell. The lower density associated with the warmer air causes buoyancy-induced flow and enhances heat transfer on the outside shell, so the natural circulation heat transfer coefficient is conservatively assumed to be doubled. For this case, about 63% of the overall thermal resistance occurs between the inside atmosphere and the inside shell surface, 36% occurs between the outside boundary temperature and the outside shell surface, and 1% occurs due to heat conduction through the shell itself. The temperature changes through the three regions are proportional to the resistances. Thus, for a total temperature change of 90 ° F, there is a 56 ° F inner film drop, a 1 ° F drop through the shell, and a 33 ° F drop through the outer film, and the minimum service temperature is approximately –7 ° F. A minimum service temperature of –15 ° F is specified for the AP1000 for added conservatism.

A738, Grade B has been used with plate thickness up to 1.15 inches in applications with a design metal temperature of –55° F. It is expected that it could be procured to meet the impact requirements of NE-2000 if the minimum service temperature requirement were -40°F.

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

Design Control Document (DCD) Revision:

None

PRA Revision:

None

NRC Additional Comments: (from Summary of 11/12-11/13 Meeting Discussion)

Westinghouse agreed to provide the heat transfer analyses conducted to demonstrate that -15° F is a bounding minimum containment vessel temperature. The analyses will address (1) overall heat transfer across the containment vessel wall for 50° F internal temperature and -40° F external temperature; and (2) the local containment vessel external surface temperature at baffle attachment locations, considering the "fin" effect of the baffles, for the same internal and external temperature conditions.

Westinghouse Response: (Revision 1):

The heat transfer analyses described in the previous response are available for review. These analyses demonstrate that -15° F is a bounding minimum containment vessel temperature. A subsequent analysis was done to determine the effect of the air baffle supports on the minimum containment vessel temperature. For this analysis, the baffle support was assumed to act as a fin with no contact resistance assumed at the attachment point. The inside containment atmosphere temperature is assumed to be 50F, and the outside ambient temperature is assumed to be –40F. A free convection heat transfer coefficient is assumed on the inside containment shell wall, and a forced convection heat transfer coefficient is assumed on the outside. The shell temperature directly beneath the baffle support is approximately –11F which is 7F lower than the minimum shell temperature away from the support. Thus, the –15F minimum service temperature is bounding.

Design Control Document (DCD) Revision:

None

PRA Revision:

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 230.018 (Response Revision 2)

Question:

It is the staff's understanding that the layouts of the coupled shield and auxiliary buildings for AP1000 and AP600 are the same and only the height of the shield building and the size of the passive containment cooling water storage tank were increased. As a result of these design changes, the dominating frequency (6.065 hz) of the AP1000 in the vertical direction is lower than that of the AP600 (6.77 hz). From Figure 3.7.1-2, "Vertical Design Response Spectra - Safe Shutdown Earthquake," one can find that the vertical responses (accelerations) of the coupled shield and auxiliary buildings for the AP1000 should be higher than those of the AP600. However, the comparison of the two designs summarized in Table 3.7.2-5 and Figure 3.7.2-4 shows an opposite conclusion. The staff's review identified the following areas for clarification:

A. Westinghouse used a detailed model between Elevation 306'-3" (the top of the tank roof) and Elevation 241'-0" (the bottom of the air vent columns) for AP600, while it used a less detailed model for AP1000. Please provide an explanation for the change in models and reason for using the less detailed model for the AP1000.

B. As summarized in Table 3.7.2-5 of DCD, Revision 0, the comparison of the vertical seismic responses (maximum absolute nodal accelerations) of the two designs indicates that the dynamic amplification in the vertical direction is higher for the AP600 than for the AP1000. Based on our engineering judgement, it is the staff's expectation that the results should be reversed, because there is no change to the building wall thickness for both designs and the shield building complex of the AP1000 is more massive than that of the AP600. Westinghouse is requested to provide an explanation to address the staff's observation.

The staff's observation regarding the dynamic amplification discussed in (a) and (b) above are also applicable for the steel containment vessel.

Westinghouse Response (Revision 1):

A. The AP1000 shield building roof is represented in the stick model by masses at the top of the roof and at the elevation of the intersection of the exterior wall of the PCS tank with the conical roof. The AP600 model also had a mass at the mid height of the tank. The roof response is primarily influenced by the conical roof and the additional mass at mid height of the tank was not necessary. Both the AP600 and AP1000 models were developed to match the dynamic properties of a detailed axi-symmetric model of the roof.

B. The maximum vertical absolute acceleration of the roof is 0.90g for the AP600 and 0.89g for the AP1000. In the most recent AP1000 analyses in the proposed revision to the DCD Section 3.7 transmitted by letter number DCP/NRC1526, the frequency is 5.81 hertz and the maximum acceleration is 0.96g. These differences in response are partly due to changes in modal properties but are also affected by the time history which envelopes the ground input spectrum of Figure 3.7.1-2 as shown in Figure 3.7.1-8.

The maximum vertical absolute acceleration of the steel containment vessel is 1.49g for the AP600 and 1.40g for the AP1000. In the most recent AP1000 analyses in the proposed revision to DCD Section 3.7 transmitted by letter DCP/NRC1526, the maximum acceleration is 1.13g. The reduction in vertical response is associated with better definition of the AP1000 polar crane and the use of a multi-mass model of the polar crane instead of the single mass used in the AP600 analyses and the initial AP1000 analyses. The description of the polar crane model is included in the proposed revision to the DCD. Table 3.7.2-2 in the proposed revision to DCD Section 3.7 transmitted by letter DCP/NRC1526 shows the modal properties of the containment vessel. A second sheet will be added to this table showing the modal properties of the containment vessel combined with the polar crane. The first frequency of the combined model in the vertical direction is 6.415 Hertz compared to 5.843 Hertz in the previous analyses.

Design Control Document (DCD) Revision: *these changes are included in Revision 3*

Revise fourth paragraph of subsection 3.7.2.3.2

The polar crane is supported on a ring girder which is an integral part of the steel containment vessel at elevation 228'-0" **as shown in Figure 3.8.2-1.** It is modeled as a **multi-**degree of freedom system attached to the steel containment shell **at elevation 224' (mid point of ring girder)** as shown in Figure 3.7.2-5. **The polar crane is modeled as shown in Figure 3.7.2-8 with five masses at the mid height of the bridge at elevation 233'-6" and one mass for the trolley.** The polar crane model includes the flexibility of the crane bridge girders and truck assembly, and the containment shell's local flexibility. **When fixed at the center of containment, the model shows fundamental frequencies of 3.7 hertz transverse to the bridge, 6.4 hertz vertically, and 8.5 hertz along the bridge.**

Add sheet 2 to Table 3.7.2-2 showing modal properties of steel containment vessel combined with polar crane

Revise Figure 3.7.2-5 as shown in the proposed revision to DCD Section 3.7 transmitted by letter number DCP/NRC1526.

Add Figure 3.7.2-8 as shown on page 230.018 (R1) -5

PRA Revision: None

Table 3.7.2-2 (Sheet 1 of 2)

STEEL CONTAINMENT
VESSEL LUMPED-MASS STICK MODEL (WITHOUT POLAR CRANE)
MODAL PROPERTIES

		Effective Mass		
Mode	Frequency	X Direction	Y Direction	Z Direction
1	6.309	2.380	159.153	0.005
2	6.311	159.290	2.382	0.000
3	12.942	0.018	0.000	0.000
4	16.970	0.000	0.006	171.030
5	18.960	0.102	40.263	0.002
6	18.970	40.161	0.102	0.000
7	28.201	0.000	0.000	28.073
8	31.898	0.054	2.636	0.000
9	31.999	2.789	0.057	0.000
10	37.990	0.909	0.007	0.000
11	38.634	0.022	4.846	0.009
12	38.877	3.758	0.014	0.000
13	47.387	0.000	0.000	5.066
14	54.039	4.649	0.633	0.000
15	54.065	0.624	4.693	0.002
16	60.628	0.002	0.042	3.389
17	62.734	0.147	0.001	0.018
18	63.180	0.000	0.050	7.069
19	63.613	0.002	0.001	0.003
20	65.994	0.022	0.659	0.041
Sum of Effective Masses		214.929	215.545	214.706

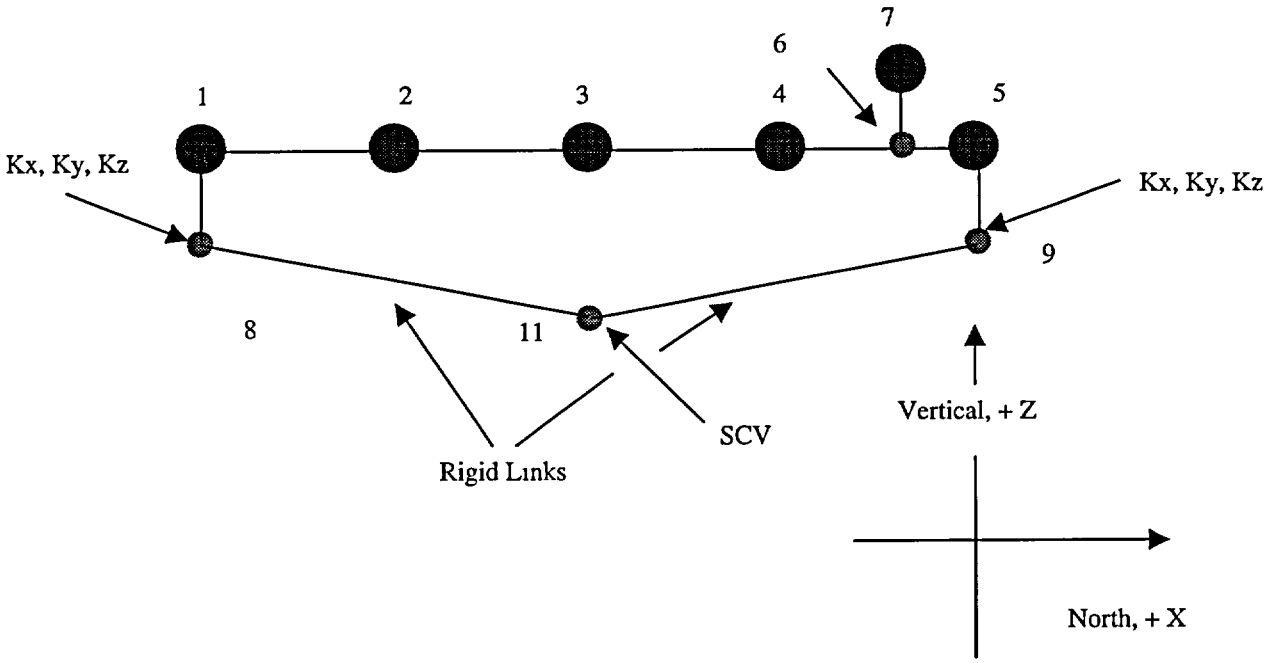
Note:
1. Fixed at Elevation 100′.
2. The total mass of the containment vessel is 225.697 kip-sec^2/ft.

Table 3.7.2-2 (Sheet 2 of 2)

STEEL CONTAINMENT
VESSEL LUMPED-MASS STICK MODEL (WITH POLAR CRANE)
MODAL PROPERTIES

		Effective Mass		
Mode	Frequency	X Direction	Y Direction	Z Direction
1	3.619	0.000	41.959	0.000
2	5.387	175.274	0.000	0.175
3	6.192	0.000	148.385	0.005
4	6.415	3.321	0.000	24.074
5	9.422	0.002	1.017	0.000
6	9.674	10.510	0.000	0.532
7	12.811	0.015	0.001	0.000
8	15.757	0.004	0.320	0.010
9	16.367	3.103	0.003	159.153
10	17.495	28.537	0.001	19.546
11	18.944	0.000	40.053	0.001
12	21.043	10.724	0.000	0.426
13	22.102	0.000	0.005	0.000
14	27.340	0.054	0.000	18.661
15	30.387	2.978	0.001	1.559
16	31.577	0.002	3.526	0.004
17	35.033	0.194	0.006	3.895
18	35.535	0.211	0.027	0.399
19	35.646	0.000	1.451	0.019
20	37.599	0.325	0.426	0.007
Sum of Effective Masses		235.254	237.181	228.465

Note:
1. Fixed at Elevation 100′.
2. The total mass of the containment vessel with the polar crane is 255.85 kip-sec^2/ft.



Local SCV Stiffness are Kx, Ky, Kz

Dynamic Degrees of Freedom

- Masses at nodes 1, 2, 3, 4, 5, and 7
- All Mass nodes have DOFs in X, Y, and Z directions

Comments:

1. Cross Beams between girders are represented by rotation spring constants Kxx and Kzz
2. Cross Beam rotational spring constant Kyy is negligible compared to girder stiffness

Figure 3.7.2-8

Polar Crane Model

Extract from NRC Notes on meeting November 12-16

The staff also requested a similar clarification for the vertical dynamic amplification for the steel containment vessel. In its response, Westinghouse indicated that the vertical acceleration response of the steel containment vessel, 1.49g for AP600 and 1.40g for the AP1000 and the comparison is similar to that for the vertical response of the shield building roof. However, in the most recent AP1000 analyses in the proposed revision to DCD Section 3.7, the maximum vertical acceleration response is significantly reduced to 1.13g. Westinghouse attributed such reduction in the vertical response to the use of a multi-mass model for the polar crane instead of the single-mass model used in both the AP600 and the initial AP1000 analyses. To incorporate the change from the single-mass to multi-mass model of the polar crane, Westinghouse proposed the following revisions to the AP1000 DCD:

- Revise the fourth paragraph in Subsection 3.7.2.3.2 to describe the multi-mass polar crane model
- Add new Figure 3.7.2-8 to show the polar crane model
- Revise Figure 3.7.2-5 to reference Figure 3.7.2-8 for the polar crane model

The proposed DCD revisions sufficiently described the multi-mass polar crane model, but did not provide a sufficient basis for the significantly reduced vertical acceleration of 1.13g for the steel containment vessel. Westinghouse agreed to provide additional justification regarding the reduction of the vertical acceleration by using the new polar crane model.

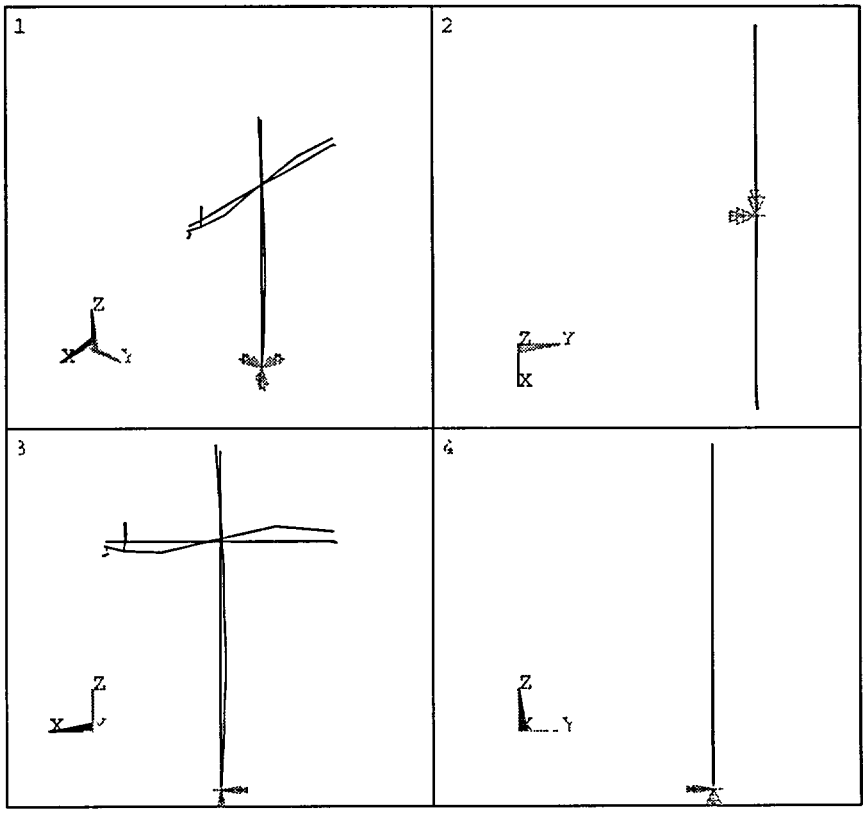
Westinghouse Response (Revision 2):

In revision 1 to this response Westinghouse included Table 3.7.2-2 (sheet 2) in the DCD showing modal properties of the steel containment vessel combined with the polar crane.

Table 230.18-1 shows the significant modes from these tables contributing to the vertical response as well as the corresponding data for the containment vessel with a one mass model of the polar crane used in the previous AP1000 analyses documented in DCD Rev 1. The table includes results for a concentric stick model of the nuclear island, which includes a one mass model of the polar crane with the same local shell flexibility as that in the multi mass model. The table also shows the maximum vertical acceleration of the containment vessel at the top of the dome and at the crane girder from analyses of the combined nuclear island stick models. The single mass polar crane models show larger vertical accelerations than the multi mass model. The polar crane multi mass model introduces a mode (at 17.495 Hz) with coupling between the vertical and horizontal responses. The shape of this mode is shown in Figure 230.18-1. It is a rotational mode of the polar crane and containment vessel with coupling between the horizontal and vertical directions. This additional mode accounts for the reduction in vertical response.

Table 230.18-1
Significant Modes for Vertical Response

	SCV only DCD Rev 3		SCV + 5 mass PC DCD Rev 3		SCV + 1 mass PC DCD Rev 1		SCV + 1 mass PC Concentric	
Description	Freq	Mass (Z)	Freq	Mass (Z)	Freq	Mass (Z)	Freq	Mass (Z)
Polar crane vertical mode			6.415	24.07	5.84	29.92	6.37	23.31
SCV fundamental vertical mode	16.97	171.03	16.37	159.15	16.84	168.34	16.58	180.80
Polar crane second vertical mode with SCV rotation			17.50	28.54(X) 19.55(Z)				
SCV second vertical mode	28.20	28.07	27.34	18.66	28.36	26.93	27.75	24.26
Maximum vertical acceleration (g)								
At top of dome				1.13		1.40		1.44
At crane girder				0.56		0.74		0.76



Mode 10, Frequency: 17.4953874 Hz

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DEC 11 2002
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PLOT NO.  13
DISPLACEMENT
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SUB =10
FREQ=17.495
RSYS=0
DMX =.145965
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ROT

*DSCA=50
XV  =1
YV  =1
ZV  =1
DIST=126.565
XF  =.199509
YF  =-35.072
ZF  =192.558
VUP =Z
Z-BUFFER

WIND=2
*DSCA=50
ZV  =1
DIST=67.748
XF  =.199509
YF  =-35.072
ZF  =192.558
VUP =Z
Z-BUFFER
```

Figure 230.018-1

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 250.003 (Response Revision 1)

Original Question:

The requirements for the Steam Generator (SG) Tube Surveillance Program are contained in technical specification (TS) 5.5.5. This TS specifies that "SG tube sample size selection, sample size expansion, inspection results classification criteria, tube inspection frequency, plugging and repair limits, and specific definitions and limits be in accordance with [Regulatory Guide 1.83, Revision [ ], date]." (Square bracketed information is to be defined when TSs are determined for the combined license applicant.) The most recent revision of RG 1.83 is Revision 1, dated July 1975. Specifying technical specification inspection requirements to be in accordance with this RG is inappropriate since the RG contains guidance and not requirements, i.e., recommended surveillances are written in terms of actions that should be taken. The guidance in this RG was superceded by the SG technical specifications in various documents, the most recent of which being NUREG-0452, Revision 4, "Standard Technical Specifications (STS) for Westinghouse Pressurized Water Reactors." The TS surveillance requirements for all domestic SGs are very similar, if not identical, to those in NUREG-0452, Revision 4, and under the Improved Standard Technical Specification program these surveillance requirements are unchanged. These requirements contain some essential surveillance requirements missing from RG 1.83, Revision1, such as definitive sample expansion criteria. In addition, TS Section 5.6.8, SG Tube Inspection Report, refers to condition C-3 for submitting certain reports; C-3 is not defined in RG 1.83 or elsewhere in the TSs although it is defined in the STS. Please revise the SG Tube Surveillance Program TSs to be consistent with the surveillance requirements contained in STS in NUREG-0452, Revision 4. (Section 5.4.2)

Westinghouse Original Response:

The Steam Generator (SG) Tube Surveillance Technical Specifications (TSs) will be revised to be consistent with the SG surveillance requirements included in NUREG 1431, V1, Rev. 2, "Standard Technical Specifications Westinghouse Plants" dated April 2001. The technical specification surveillance requirements for all domestic SGs under NUREG-0452, Rev. 5 are very similar and remain unchanged under NUREG-1431, V1, Rev 2. Please note that AP1000 does not include an "Operating Basis Earthquake" (OBE) in its design basis, and therefore TS 5.5.5.3.c.2. and 5.5.5.4.a.7 instead refer to "one-third of the Safe Shutdown Earthquake" (SSE) consistent with DCD section 3.7. The changes are identified below in the Design Control Document (DCD) Revision portion of this RAI. The TS revision is included in the TS revision in response to RAI 630.001.

Design Control Document (DCD) Original Revision:

Replace TS 5.5.5 with the following:

5.5.5 Steam Generator (SG) Tube Surveillance Program

The provisions of SR 3.0.2 are applicable to the SG Tube Surveillance Program Test Frequencies.

5.5.5.0 Each steam generator shall be demonstrated OPERABLE by performance of the following augmented inservice inspection program.

5.5.5.1 Steam Generator Sample Selection and Inspection

Each steam generator shall be determined OPERABLE during shutdown by selecting and inspecting at least the minimum number of steam generators specified in Table 5.5.5-1.

5.5.5.2 Steam Generator Tube Sample Selection and Inspection

The steam generator tube minimum sample size, inspection result classification, and the corresponding action required shall be as specified in Table 5.5.5-2. The inservice inspection of steam generator tubes shall be performed at the frequencies specified in Specification 5.5.5.3, and the inspected tubes shall be verified acceptable per the acceptance criteria of Specification 5.5.5.4. The tubes selected for each inservice inspection shall include at least 3% of the total number of tubes in all steam generators. The tubes selected for these inspections shall be selected on a random basis except:

a. Where experience in similar plants with similar water chemistry indicates critical areas to be inspected, then at least 50% of the tubes inspected shall be from these critical areas.

b. The first sample of tubes selected for each inservice inspection (subsequent to the preservice inspection) of each steam generator shall include:

1. All nonplugged tubes that previously had detectable wall penetrations greater than 20%.

2. Tubes in those areas where experience has indicated potential problems.

3. A tube inspection (pursuant to Specification 5.5.5.4.a.8) shall be performed on each selected tube. If any selected tube does not permit the passage of the eddy current probe for a tube inspection, this shall be recorded and an adjacent tube shall be selected and subjected to a tube inspection.

c. The tubes selected as the second and third samples (if required by Table 5.5.5-2) during each inservice inspection may be subjected to a partial tube inspection provided:

1. The tubes selected for these samples include the tubes from those areas of the tube sheet array where tubes with imperfections were previously found.

2. The inspections include those portions of the tubes where imperfections were previously found.

The results of each sample inspection shall be classified into one of the following three categories:

Category	Inspection Results
C-1	Less than 5% of the total tubes inspected are degraded tubes and none of the inspected tubes are defective.
C-2	One or more tubes, but not more than 1% of the total tubes inspected are defective, or between 5% and 10% of the total tubes inspected are degraded tubes.
C-3	More than 10% of the total tubes inspected are degraded tubes or more than 1 % of the inspected tubes are defective.

Note: In all inspections, previously degraded tubes must exhibit significant (greater than 10%) further wall penetrations to be included in the above percentage calculations.

5.5.5.3 Inspection Frequencies

The above required inservice inspections of steam generator tubes shall be performed at the following frequencies:

a. The first inservice inspection shall be performed after 6

Effective Full Power Months but within 24 calendar months of initial criticality. Subsequent inservice inspections shall be performed at intervals of not less than 12 nor more than 24 calendar months after the previous inspection. If two consecutive inspections following service under AVT conditions, not including the preservice inspection, result in all inspection results falling into the C-1 category or if two consecutive inspections demonstrate that previously observed degradation has not continued and no additional degradation has occurred, the inspection interval may be extended to a maximum of once per 40 months.

b. If the results of the inservice inspection of a steam generator conducted in accordance with Table 5.5.5-2 at 40 month intervals fall in Category C-3, the inspection frequency shall be increased to at least once per 20 months. The increase in inspection frequency shall apply until the subsequent inspections satisfy the criteria of Specification 5.5.5.3.a; the interval may then be extended to a maximum of once per 40 months.

c. Additional, unscheduled inservice inspections shall be performed on each steam generator in accordance with the first sample inspection specified in Table 5.5.5-2 during the shutdown subsequent to any of the following conditions:

1. Primary-to-secondary tube leaks (not including leaks originating from tube-to-tubesheet welds) in excess of the limits of Specification 3.4.8.

2. A seismic occurrence greater than one-third of the Safe Shutdown Earthquake.

3. A loss-of-coolant accident requiring actuation of the engineered safeguards.

4. A main steam line or feedwater line break.

5.5.5.4 Acceptance Criteria

a. As used in this Specification:

1. Imperfection means an exception to the dimensions,

finish or contour of a tube from that required by fabrication drawings or specifications. Eddy-current testing indications below 20% of the nominal wall thickness, if detectable, may be considered as imperfections.

2 Degradation means a service-induced cracking wastage, wear or general corrosion occurring on either inside or outside of a tube.

3. Degraded Tube means a tube that contains imperfections greater than or equal to 20% of the nominal wall thickness caused by degradation.

4. % Degradation means the percentage of the tube wall thickness affected or removed by degradation.

5. Defect means an imperfection of such severity that it exceeds the plugging limit. A tube containing a defect is defective.

6. Plugging Limit means the imperfection depth at or beyond which the tube shall be removed from service by plugging and is greater than or equal to 40% of the nominal tube wall thickness.

7. Unserviceable describes the condition of a tube if it leaks or contains a defect large enough to affect its structural integrity in the event of a one-third of the Safe Shutdown Earthquake, a loss-of-coolant accident, or a steam line or feedwater line break as specified in 5.5.5.3.c, above.

8. Tube Inspection means an inspection of the steam generator tube from the point of entry (hot leg side) completely around the U-bend to the top support of the cold leg.

9. Preservice Inspection means an inspection of the full length of each tube in each steam generator performed by eddy current techniques prior to service to establish a baseline condition of the tubing. This inspection shall be performed using the equipment and techniques expected to be used during subsequent inservice inspections.

b. The steam generator shall be determined OPERABLE after completing the corresponding actions (plugging of all tubes exceeding the plugging limit) required by Table 5.5.5-2.

Table 5.5.5-1

No. of Steam Generators per Unit	**Two**
First Inservice Inspection	**One**
Second and Subsequent Inservice Inspections	**One***

* The other steam generator not inspected during the first inservice inspection shall be reinspected. The third and subsequent inspections may be limited to one steam generator on a rotating schedule encompassing 3 N% of the tubes (where N is the number of steam generators in the plant) if the results of the first or previous inspections indicate that all steam generators are performing in a like manner. If the condition of the tubes in one steam generator are found to be more severe than in the other steam generator, the SG sampling sequence at the subsequent inspection shall be modified to examine the steam generator with the more severe condition.

Table 5.5.5-2
Steam Generator Tube Inspection

	1st Sample Inspection		2nd Sample Inspection		3rd Sample Inspection	
Sample Size	Result	Action Required	Result	Action Required	Result	Action Required
A minimum of S Tubes per SG	C-1	None	N/A	N/A	N/A	N/A
	C-2	Plug defective tubes and inspect additional 2S tubes in this SG	C-1	None	N/A	N/A
			C-2	Plug defective tubes and inspect additional 4S tubes in this SG	C-1	None
					C-2	Plug defective tubes
					C-3	Perform action for C-3 result of first sample
			C-3	Perform action for C-3 result of first sample	N/A	N/A
	C-3	Inspect all tubes in this SG, plug defective tubes and inspect 2S tubes in each other SG Notification to NRC pursuant to 10 CFR 50.73	All other SGs are C-1	None	N/A	N/A
			Some SGs C-2 but no additional SGs are C-3	Perform action for C-2 result of second sample	N/A	N/A
			Additional SG is C-3	Inspect all tubes in each SG and plug defective tubes. Notification to NRC pursuant to 10 CFR 50.73	N/A	N/A

$S=\frac{3N}{n}\%$ Where N is the number of steam generators in the unit, and n is the number of steam generators inspected during an inspection.

Replace TS 5.6.8 with the following:

5.6.8 Steam Generator Tube Inspection Report

a. Following each inservice inspection of steam generator tubes, the number of tubes plugged in each steam generator shall be reported to the Commission within 15 days of the completion of the plugging effort.

b. The complete results of the steam generator tube inservice inspection shall be submitted to the Commission within 12 months following the completion of the inspection. This Report shall include:

   1. Number and extent of tubes inspected.
   2. Location and percent of wall-thickness penetration for each indication of an imperfection.
   3. Identification of tubes plugged.

c. Results of steam generator tube inspections which fall into Category C-3 shall be considered a Reportable Event and shall be reported pursuant to 10 CFR 50.73 prior to resumption of plant operation. The written report shall provide a description of investigations conducted to determine the cause of the tube degradation and corrective measures taken to prevent recurrence.

PRA Original Revision:

None

NRC Additional Comments:

The staff has the following issues with the proposed SG Tube Surveillance Program TSs:

a. The proposed TSs indicate that the provisions of SR 3.0.2 are applicable. The staff position as articulated in NRC Generic Letter 91-04 is that the surveillance interval extension in 3.0.2 do not apply to SG inspection intervals because the TS 5.5.5.3.a. and b. address those conditions under which the surveillance interval for SG tube inspections may be extended to a maximum of once per 40-months and TS 5.5.5.3.b. addresses when the SG tube inspection frequency shall be increased to at least once per 20 months.

   The statement in the TS needs to be revised to indicate that the provisions of SR 3.0.2 are not applicable.

b. The TS Table 5.5.5-1 does not reflect the strategy for the minimum number of SGs to be inspected during subsequent inservice inspections depending upon whether preservice inspection was performed. This table needs to be revised to reflect preservice inspection.

Westinghouse Additional Response: (Revision 1)

The requested changes will be incorporated into the DCD.

Design Control Document (DCD) Revision: (Revision 1)

The following changes will be made to Revision 3 of the DCD:

Change Section 5.5.5:

5.5.5 Steam Generator (SG) Tube Surveillance Program

.

5.5.5.0 Each steam generator shall be demonstrated OPERABLE by performance of the following augmented inservice inspection program.

Change Section 5.5.5.3 by adding item "d."

5.5.5.3 Inspection Frequencies

d. The provisions of Specification 3.0.2 do not apply for extending the frequency of performing inservice inspections as specified in Specifications 5.5.5.3a and 5.5.5.3b.

Modify Table 5.5.5-1 as follows:

Table 5.5.5-1

No. of Steam Generators per Unit	**Two**
First Inservice Inspection	**One***
Second and Subsequent Inservice Inspections	**One****

* All steam generators shall be inspected during the first inservice inspection if no preservice inspection was conducted.

** The other steam generator not inspected during the first inservice inspection shall be reinspected. The third and subsequent inspections may be limited to one steam generator on a rotating schedule encompassing 3 N% of the tubes (where N is the number of steam generators in the plant) if the results of the first or previous inspections indicate that all steam generators are performing in a like manner. If the condition of the tubes in one steam generator are found to be more severe than in the other steam generator, the SG sampling sequence at the subsequent inspection shall be modified to examine the steam generator with the more severe condition.

PRA Revision: (Revision 1)

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 251.004 (Response Revision 1)

Question:

Due to the primary water stress corrosion cracking (PWSCC) of the V. C. Summer primary loop welds, the staff finds that the information that we have today is substantially different from the information that was available when we approved leak-before-break (LBB) applications for existing pressurized water reactor (PWR) systems which contain Inconel 82/182 materials. The following three questions are related to staff concerns regarding this recently discovered degradation mechanism as it applies to any LBB-candidate piping systems proposed in AP1000. (DCD Section 3.6.3)

A. Section 5.2.3 of the DCD indicates that the "use of nickel-chromium-iron alloy in the reactor coolant pressure boundary is limited to Alloy 690. Alloy 600 may be used in limited areas for welding or buttering. Where Alloy 600 is used, it is not in contact with the reactor coolant." However, in addition to the reactor coolant system (RCS) piping, there is LBB-candidate piping, for example the passive core cooling system, exposed to primary water under temperature and pressure conditions similar to those in the RCS. Discuss the susceptibility of these systems to PWSCC.

B. Provide test and plant operational data regarding the crack growth rate for Alloy 52/152 welds to be used in contact with reactor coolant in the proposed lines for which LBB will be applied and demonstrate that this material is not susceptible to PWSCC.

C. LBB is based, in part, upon the premise that LBB will only be applied to piping materials that are not susceptible to any known degradation mechanisms. Until sufficient information is acquired to ensure that Inconel 52/152 materials are essentially "PWSCC resistant" through the anticipated 60 year operational lifetime of an AP1000 facility, the staff believes that augmented inservice inspection of Inconel welds in LBB lines, including the use of inside-diameter (ID) eddy current on a periodic basis, is an essential element for approval of the AP1000 "design" to support application of LBB. To facilitate resolution of the PWSCC issue for AP1000, please provide an inspection plan that the combined licensee would be required to perform. This inspection plan should address additional inspection techniques (e.g., eddy current testing) to supplement ultrasonic testing (UT) so that tight flaws in piping welds similar to those detected in the V. C. Summer primary loop weld could be detected.

Westinghouse Response:

A. The following thirteen AP1000 piping systems are defined as Leak-Before-Break systems and identified in the appropriate figures in Appendix 3E of the DCD.

RCS	Reactor Coolant Loop (RCL)
RCS	1st, 2nd, 3rd Stage Automatic Depressurization System
RCS	Pressurizer Surge Line
RCS	4th Stage ADS (East)
RCS	4th Stage ADS (West)
RNS	Normal Residual Heat Removal Suction
PXS	Passive RHR Return
PXS	Direct Vessel Injection – A
PXS	Direct Vessel Injection – B
PXS	Core Make-Up (A)
PXS	Core Make-Up (B)
SGS	Main Steam Line A
SGS	Main Steam Line B

With the exception of the Main Steam lines, which are connected directly to the steam generators, all other LBB piping systems are connected to the Reactor Coolant primary system via the Reactor Coolant Loop, Reactor Pressure Vessel, or the Pressurizer.

Alloy 600 will not be used for any of the AP1000 LBB candidate piping systems.

B. Background and Experience - SCC Resistance of Alloys 52 and 152

INTRODUCTION

Alloy 52 is the filler metal used for the joining of Alloy 690 components by either the gas-tungsten arc welding (GTAW) or gas metal arc welding (GMAW) processes. The welding electrode used for the shielded metal arc welding (SMAW) process is Alloy 152. Both of these materials have compositions not differing greatly from the parent Alloy 690 material. Nominal compositions are provided in the following table.

Element	Alloy 690	Alloy 152	Alloy 52
	Base Metal	E-NiCrFe-7	ER-NiCrFe-7
	SB-167	SMAW	GTAW/GMAW
C	0.05 max	0.05 max	0.04 max
Mn	0.5 max	5.00 max	1.00 max
Fe	7.0 to 11.0	7.0 to 12.0	7.0 to 11.0
P	-	0.03 max	0.02 max
S	0.015 max	0.015 max	0.015 max
Si	0.5 max	0.75 max	0.5 max
Cu	0.5 max	-	0.3 max
Ni	58.0 min	Bal	Bal
Co	-	Incl. with Ni	Incl. with Ni
Al	-	0.50 max combined	1.10 max Al or 1.50 max combined
Ti	-		
Cr	27.0 to 31.0	28.0 to 31.5	28.0 to 31.5
Nb + Ta	-	1.0 to 2.5	0.10 max
Mo	-	0.50 max	0.50 max
Other elements	-	0.50 max	0.50 max

Essentially coincident with the introduction of Alloy 690, Alloys 52 and 152 have been used for all fusion welding applications as the material of choice for applications with Alloy 690. The following provides a summary of the experience with respect to these filler metals in service and in laboratory testing.

SERVICE EXPERIENCE

The majority of the operating plant experience with Alloy 690 and the weld metals Alloys 52 and 152 is associated with replacement steam generator (SG) programs beginning in approximately 1994 with the Delta 75 replacements for V. C. Summer **and the Model 54F replacements for North Anna Unit 1..** In addition to the exclusive use of Alloy 690 for the SG heat transfer tubing applications, the weld metals were used for a range of applications in which contact with primary reactor coolant was required. A brief summary of the weld metal applications, for Westinghouse-designed components, follows. **The reference date for Time in Service is February 2003.**

Plant	Approx. Time in Service (years)	Component	Material*	Application
V. C. Summer	8	SG nozzle welds	Alloy 52 and/or Alloy 152	Buttering over Alloy 82/Alloy 182 welds
North Anna 1	9	Safe end-nozzle welds		
North Anna 2	7	Divider plate-channel head & stub runner		Final weld layer (in contact with RCS)
Point Beach 2	6	Tubesheet cladding	Alloy 52 and/or Alloy 152	All buttering, cladding and welding operations
Kori 1	5	SG nozzle welds		
Shearon Harris	2	Safe end-nozzle welds		
South Texas 1	3	Divider plate-tubesheet welds		
South Texas 2	1			
ANO-2	2			
Farley 1	3			
Farley 2	2			
Kewaunee	2			
* - Nearly all procedures permit either Alloy 52 or Alloy 152 to be used				

In addition to these Westinghouse units, similar experience has been accrued with replacement **steam generators** in Europe and in Japan.

There have been no reported instances of environmental degradation of any kind for any of these applications; this includes both the Alloy 690 base metal and the Alloy 52 or Alloy 152 weld metals.

This experience is fully consistent with expectations from laboratory testing performed to support the qualification of these materials. This class of austenitic nickel-base alloys, containing greater than 27 wt. pct. chromium, has exhibited full resistance to primary water stress corrosion cracking (PWSCC), to the extent that they are generally regarded as immune to this form of environmental degradation.

This experience combined with the growing operating plant experience, provided the basis for the use of Alloys 52 and 152 for the recent primary loop nozzle repairs at V. C. Summer.

LABORATORY EXPERIENCE

For the reasons implied above, i.e., lack of experience with PWSCC of Alloy 690, relatively little testing for either crack initiation or crack propagation has been performed for either the base metal or the weld metals.

Psaila-Dombrowski et al. (Ref. 1) evaluated the SCC resistance of Alloy 152 welds in primary water environments using constant extension rate tests (CERT) at 343°C (650°F). **The CERT tests use smooth tensile specimens loaded so as to cause uniform, constant strain. The ultimate stress level in these tests ranged between 70 and 80 ksi, with individual test duration in the range of 100 to 170 hours.** Examination of the fracture surfaces indicated no environmentally-related degradation. All fracture occurred by ductile rupture.

Psaila-Dombrowski et al. (Ref. 2) performed a series of CERT tests on Alloys 52 and 152 weldments in simulated primary water at 343°C (650°F). **These tests, which were also performed on smooth tensile specimens, were conducted with a strain rate of $5x10^{-8}$/sec, over a test period of 4122 hours. The total exposure time in these tests was 4122 hours. Environmentally related cracking was not observed in either the Alloy 52 or the Alloy 152 specimens. Similar resistance to SCC was observed for Alloy 690 CERT specimens tested in the same program. However, modest secondary cracking was seen in Alloy 82 specimens.**
Westinghouse recently completed a series of accelerated stress corrosion cracking tests, in a 400°C (750°F) doped steam environment, on weld metal specimens of Alloy

52M (a modified version of Alloy 52 used for recent nozzle repairs in Sweden) and Alloy 182 (Ref. 3). These specimens were tested as flat plates, bolt-loaded to strains of 0.35% and 1.0% in a four-point bent beam configuration. These tests are used to characterize resistance to PWSCC crack initiation. Alloy 600 base metal specimens, prepared from archived sections of a CRDM nozzle, were also tested as control specimens. In exposure times equivalent to more than forty years at plant operating conditions, Alloy 52M exhibited complete resistance to stress corrosion crack initiation. In comparison, crack initiation was observed in the Alloy 182 weld metal and Alloy 600 base metal control specimens in exposure times less than one-fifth the total exposure time of the Alloy 52M specimens.

These are the only published test results with which we are familiar.

REFERENCES

1. M. J. Psaila-Dombrowski et al., "Evaluation of Weld Metal 82 and Weld Metal 182 Stress Corrosion Cracking Susceptibility," *Proceedings, Seventh International Symposium on Environmental Degradation of Materials in Nuclear Power Systems – Water Reactors*, NACE Int'l. (1995) 81-91.

2. M. J. Psaila-Dombrowski et al., "Evaluation of Weld Metals 82, 152, 52 and Alloy 690 Stress Corrosion Cracking and Corrosion Fatigue Susceptibility," *Proceedings, Eighth International Symposium on Environmental Degradation of Materials in Nuclear Power Systems – Water Reactors*, ANS (1997) 412-421.

3. **R. J. Jacko, R. E. Gold and A. Kroes, "Accelerated Corrosion Testing of Alloy 52M and Alloy 182 Weldments," to be presented at the *11th International Conference on Environmental Degradation of Materials in Nuclear Power Systems - Water Reactors*, August 2003, ANS sponsorship.**

C. As explained in response to question b above, the proposed **Alloy** 52/152 weld material is the material of choice for the industry and for AP1000 and has better crack resistance than **Alloy** 82/182 materials. Augmented inservice inspection of **Alloy** 52/152 materials welds including the use of inside-diameter (ID) eddy current on a periodic basis has not been

required for the operating plants and therefore, should not be required for the AP1000 applications.

NRC Additional Comments:

B. The operating plant experience provided by Westinghouse indicates no PWSCC phenomenon for Alloy 52/152 welds for up to seven years of operation. This, however, only reflected that the crack initiation or incubation time for PWSCC is probably more than seven years. Since the PWSCC for Alloy 82/182 in primary system piping welds surfaced after an operation period of considerably longer than seven years, the operational data provided is not sufficient to establish the superiority of Alloy 52/152 welds. Separately, please elaborate on the preparation of the flaw in the specimens used in the CERT tests, mentioned by Westinghouse in its response under the title "Laboratory Experience," to justify that crack initiation time has been bypassed by introducing proper flaws in the specimens, and the test results are related to PWSCC growth or propagation only.

C. The information provided by Westinghouse on this part of the RAI is non-responsive. The staff will discuss with Westinghouse the need for a commitment to implement augmented inspection similar to inspections operating plants may implement in the future to address the potential for PWSCC to occur in 82/182/Alloy 600 welds in LBB piping and the timing for such inspections.

Westinghouse Additional Response:

B. Westinghouse has revised the response to include additional details regarding the operating experience for Alloy 51/152. In addition, the response has been revised to elaborate on the preparation of the flaw in the specimens used in the CERT tests referenced in the response under the title "Laboratory Experience," to justify that crack initiation time has been bypassed by introducing proper flaws in the specimens.

C. Westinghouse recognizes that the industry will continue to monitor the performance of the materials proposed for the AP1000 application discussed in this response. At this time, Westinghouse does not propose to require augmented inspections of the AP1000 primary system welds that use Alloy 52/152. The AP1000 inspection program is the responsibility of the Combined Operating License (COL) applicant. To resolve this issue, Westinghouse will include a COL applicant commitment to define the inspection program at the time of the COL application, and decide at that time the specifics of the program. This approach will afford the NRC and the COL applicant to use the additional operating experience to properly define augmented inspections as necessary.

Design Control Document (DCD) Revision:

A COL action item will be included in DCD section 3.6.4 as shown below:

3.6.4 Combined License Information

3.6.4.1 Pipe Break Hazard Analysis

Combined License applicants referencing the AP1000 certified design will complete the final pipe whip restraint design and address as built reconciliation of the pipe break hazards analysis in accordance with the criteria outlined in subsections 3.6.1.3.2 and 3.6.2.5. The as-built pipe rupture hazard analysis will be documented in an as-built Pipe Rupture Hazards Analysis Report.

3.6.4.2 Leak-before-Break Evaluation of as-Designed Piping

Combined License applicants referencing the AP1000 certified design will complete the leak-before-break evaluation by comparing the results of the as-designed piping stress analysis with the bounding analysis curves documented in Appendix 3B. The Combined License applicant may perform leak-before-break evaluation for a specific location and loading for cases not covered by the bounding analysis curves. The leak-before-break evaluation will be documented in a leak-before-break evaluation report.

3.6.4.3 Leak-before-Break Evaluation of as-Built Piping

Combined License applicants referencing the AP1000 certified design will address: 1) verification that the as-built stresses, diameter, wall thickness, material, welding process, pressure, and temperature in the piping excluded from consideration of the dynamic effects of pipe break are bounded by the leak-before-break bounding analysis; 2) a review of the Certified Material Test Reports or Certifications from the Material Manufacturer to verify that the ASME Code, Section III strength and Charpy toughness requirements are satisfied; and 3) complete the leak-before-break evaluation by comparing the results of the final piping stress analysis with the bounding analysis curves documented in Appendix 3B. The leak-before-break evaluation will be documented in a leak-before-break evaluation report.

3.6.4.4 Primary System Inspection Program for Leak-before-Break Piping

Combined License applicants referencing the AP1000 certified design will develop an inspection program for piping systems that are qualified for Leak-before-Break. The inspection program will consider the operating experience of the materials used in the AP1000 piping systems qualified for Leak-before-Break, and will consider the need for augmented inspections to those required by the applicable portions of the ASME code.

Table 1.8-2 (Sheet 2 of 6)

SUMMARY OF AP1000 STANDARD PLANT COMBINED LICENSE INFORMATION ITEMS

Item No.	Subject	Subsection
2.5-13	Subsurface Instrumentation	2.5.4.6.11
2.5-14	Stability of Slopes	2.5.5
2.5-15	Embankments and Dams	2.5.6
3.3-1	Wind and Tornado Site Interface Criteria	3.3.3
3.4-1	Site-Specific Flooding Hazards Protective Measures	3.4.3
3.5-1	External Missile Protection Requirements	3.5.4
3.6-1	Pipe Break Hazards Analysis	3.6.4.1
3.6-2	Leak-Before-Break Evaluation of as-Designed Piping	3.6.4.2
3.6.3	Leak-Before-Break Evaluation of as-Built Piping	3.6.4.3
3.6-4	**Primary System Inspection Program for Leak-before-Break Piping**	**3.6.4.4**
3.7-1	Seismic Analysis of Dams	3.7.5.1
3.7-2	Post-Earthquake Procedures	3.7.5.2
3.7-3	Seismic Interaction Review	3.7.5.3
3.7-4	Reconciliation of Seismic Analyses of Nuclear Island Structures	3.7.5.4
3.7-5	Seismic Analyses of Nuclear Island Structures at Soil Sites	3.7.5.5
3.8-1	Containment Vessel Design Adjacent to Large Penetrations	3.8.6.1
3.8-2	Passive Containment Cooling System Water Storage Tank Examination	3.8.6.2
3.8.3	Design Summary Reports - Structures	3.8.6.3
3.8-4	As-Built Summary Report	3.8.6.4
3.9-1	Reactor Internal Vibration Response	3.9.8.1
3.9-2	Design Specification and Reports	3.9.8.2
3.9-3	Snubber Operability Testing	3.9.8.3
3.9-4	Valve Inservice Testing	3.9.8.4
3.9-5	Surge Line Thermal Monitoring	3.9.8.5
3.9-6	Piping Benchmark Program	3.9.8.6
3.10-1	Experience-Based Qualification	3.10.6

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

PRA Revision:

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 251.029 (Response Revision 1)

Original Question:

It was mentioned in Section 10.2.3.6 that the maintenance and inspection program plan for the turbine assembly and valves is based on turbine missile probability calculations reported in WCAP-15783, operating experience of similar equipment, and inspection results. Provide the calculated turbine missile probability results that were used for this purpose and explain how they were used to determine the inspection intervals of 10 years for low-pressure (LP) turbines and 8 years for high-pressure (HP) turbines, the inspection intervals of 3 years for a variety of valves, and the quarterly testing frequency for valves. (Section 10.2.3)

Westinghouse Original Response:

The turbine inspection interval of assembly and valves is determined based on not only the probability of turbine missile generation but also operating experience of similar equipment and inspection results.

The maintenance and inspection program plan that applies to turbine missile generation is described in WCAPs 15783 and 15785. It is concluded that turbine missile generation probability is low enough even without inspection or maintenance for more than 30 years. According to operating experience of similar equipment and inspection results, the inspection intervals is established at 10 years for LP turbines, 8 years for HP turbines and 3 years for a variety of valves. The quarterly testing frequency for valves is based on avoiding the potential for destructive overspeed conditions due to valve failures as discussed in WCAP-15785.

Design Control Document (DCD) Original Revision:

None

PRA Original Revision:

None

NRC Additional Comments:

The methodology of WCAP-15785 is based on the failure rate derived from years of unit and component service in Japanese nuclear power stations. Please comment on the design of the

main stop and governing valves and their control systems to be used in AP1000 plant to justify the use of the above-mentioned information from Japan.

Westinghouse Additional Response: (Revision 1)

The reference AP1000 turbine main stop and governing valves, and their control systems are the same as those used in Japan.

Design Control Document (DCD) Revision: (Revision 1)

None

PRA Revision: (Revision 1)

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 252.006 (Response Revision 1)

Question:

Section 5.4.2.4.2 indicates that tubes can be supported by either an open lattice design called eggcrates, or by a support plate design. The seventh paragraph of section 5.4.2.3.3 discusses tube supports only in terms of broached hole support plate design. Please clarify. (Section 5.4.2)

Follow-On Comment:

The response indicates that the open lattice design is a possible option for the tube support design but that the steam generator design descriptions and evaluations in the DCD Section 5.4.2 are based only on the broached hole design. If the open lattice design is an option for combined operating license holders for the AP1000, the DCD Section 5.4.2 will have to be expanded to include this alternative design for NRC staff approval.

Westinghouse Response (Revision 1):

AP1000 steam generator tube support is provided by a support plate design. The steam generator design descriptions and evaluations in DCD sections **5.1.3.2 and** 5.4.2 are based on a broached hole support plate design.

DCD sections 5.1.3.2 and 5.4.2 will be revised to delete reference to the open lattice tube support design.

Design Control Document (DCD) Revision:

From DCD Revision 3 page 5.1-4:

5.1.3.2 AP1000 Steam Generator

The AP1000 steam generator (SG) is a vertical shell and U-tube evaporator with integral moisture separating equipment. The basic steam generator design and features have been proven in tests and in previous steam generators including replacement steam generator designs.

Design enhancements include nickel-chromium-iron Alloy 690 thermally treated tubes on a triangular pitch, improved antivibration bars, single-tier separators, enhanced maintenance features, and a primary-side channel head design that allows for easy access and maintenance by robotic tooling. The AP1000 steam generator employs tube supports utilizing a **broached hole** support plate design.

From DCD Revision 3 page 5.4-12, Section 5.4.2.2:

Support of the tubes is provided by ferritic stainless steel **tube support plates**. The holes in the tube support plates are broached with a hole geometry to promote flow along the tube and to provide an appropriate interface between the tube support plate and the tube. Figure 5.4-3 shows the support plate hole geometry. Anti-vibration bars installed in the U-bend portion of the tube bundle minimize the potential for excessive vibration.

From DCD Revision 3 page 5.4-15, Section 5.4.2.3.3:

Tube fluid elastic excitation is potentially more significant than either vortex shedding or turbulence. Relatively large tube amplitudes can feed back proportionally large tube driving forces if an instability threshold is exceeded. Tube support spacing, in both the tube support plates in the straight leg region and the anti-vibration bars in the U-bend region, provides tube response frequencies such that the instability threshold is not exceeded. This approach provides large margins against initiation of fluid elastic vibration for tubes effectively supported by the tube support system.

From DCD Revision 3 page 5.4-17:

5.4.2.4.2 Steam Generator Design Effects on Materials

Several features in the AP1000 steam generator minimize crevice areas and the deposition of contaminants from the secondary-side flow. Such crevices and deposits could otherwise produce a local environment allowing potential chemical concentration and material corrosion.

The portion of the tube within the tubesheet is expanded hydraulically to close the crevice between the tube and tubesheet. The length of the expansion is carefully controlled to minimize the potential of an over-expanded condition above the tubesheet and to minimize the extent of unexpanded tube at the top of the tubesheet.

The tube support plates are made of corrosion resistant Type 405 stainless steel alloy. A three-lobed, or trifoil, tube hole design provides flow adjacent to the tube outer surface. This provides high sweeping velocities at the tube and tube support plate intersections. The trifoil tube support plate provides in-plane and out-of-plane strength. The sweeping velocities through the support plate reduce sludge accumulation in the tube-to-tube support crevices. Figure 5.4-3 shows the trifoil broached holes. This support plate design contributes to a high circulation ratio. The increased flow from a high circulation ratio circulation results in increased flow in the interior of the bundle, as well as horizontal velocity across the tubesheet, which reduces the tendency for sludge deposition.

From DCD Revision 3 page 5.4-19, Section 5.4.2.4.3:

The tube support plates are fabricated of ferritic stainless steel. Laboratory tests show that this material is resistant to corrosion in the AVT environment. If corrosion of ferritic stainless steel were to occur because of the concentration of contaminants, the volume of the corrosion products is essentially equivalent to the volume of the parent material consumed. This would be expected to preclude denting. The support plates are also designed with trifoil tube holes rather than cylindrical holes. The trifoil tube hole (see Figure 5.4-3) design promotes high velocity flow along the tube and is expected to minimize the accumulation of impurities at the support plate location.

PRA Revision:

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 261.010 (Response Revision 1)

Original Question:

In addition to the power ascension test abstracts listed in RAI 261.007b, Westinghouse should provide additional information on the following power ascension test abstracts:

1. Determine that steady-state core performance is in accordance with design. Sufficient measurements and evaluations should be conducted to establish that flux distributions, local surface heat flux, linear heat rate, departure from nucleate boiling ratio (DNBR), radial and axial power peaking factors, and other important parameters are in accordance with design values throughout the permissible range of power to flow conditions. This test is designated as "b" in RG 1.68, Appendix A, Section 5.

   Power ascension test abstract Section 14.2.10.4.2, Incore Instrumentation Systems, does contain test methods to generate data from incore maps to verify core power peaking and axial distributions that are consistent with design predictions and the limits imposed by plant Technical Specifications. The test objective also states "Obtain data for incore thermocouple and flux maps at various power levels during power ascension to full power to determine flux distributions;" however, there is no statement for collection of test data for local surface heat flux, linear heat rate, departure from nucleate boiling and radial power peaking factors. This information should be added to this test abstract or another applicable test abstract in Section 14.2.10.4, Power Ascension Tests.

2. Demonstrate that gaseous and liquid radioactive waste processing, storage, and release systems operate in accordance with design. This test is designated as "c.c" in RG 1.68, Appendix A, Section 5.

   Low power test abstracts Section 14.2.9.3.1, "Liquid Radwaste System Testing," and Section 14.1.9.3.2, "Gaseous Radwaste System Testing," may cover these tests. However, Westinghouse should justify why these tests are performed at low power instead of the power ascension test phase since a much larger quantity of liquid and gaseous radioisotopes are being produced at power then during the low power test phase.

Westinghouse Original Response:

1. Westinghouse will revise DCD subsection 14.2.10.4.2 as identified in the **"Design Control Document (DCD) Revision:"** portion of this RAI response to address the concern. As stated in DCD subsection 14.4.2, the Combined License applicant is responsible for

providing test specifications and test procedures for the preoperational and startup tests. The procedures will meet the appropriate regulatory guidance.

2. Testing of the gaseous and liquid radioactive waste processing, storage, and release systems is performed at low power so that the negative impact of any system not performing as designed is minimal. The low power testing confirms that the systems performed as designed and therefore additional testing at high plant power is not necessary. This is consistent with other plants, for example, please see the Watts Bar or Vogtle FSAR.

Design Control Document (DCD) Original Revision:

Change the second bullet under Test Method, of subsection 14.2.10.4.2 Incore Instrumentation System to read as follows:

Use data from the incore maps to verify that core power distribution is consistent with design predictions and the limits imposed by the plant Technical Specifications, and to calibrate other plant instrumentation.

PRA Original Revision:

None

NRC Additional Comments:

Item 1 The NRC staff request for additional information states that "there is no statement for collection of test data for local surface heat flux, linear heat rate, departure from nucleate boiling and radial heat power peaking factors." Westinghouse deleted information related to peaking factors from the DCD. Please provide additional information on the thermal limits noted above.

Item 2 The RAI states that "Westinghouse should justify why these tests are performed at low power instead of the power ascension test phase since a much larger quantity of liquid and gaseous radioisotopes are being produced at power then during the low power test phase." Westinghouse states: "Testing of the gaseous and liquid radioactive waste processing, storage and release systems is performed at low power so that the negative impact of any system not performed as designed is minimal. The low power testing confirms that the systems performed as designed and therefore additional testing at high power is not necessary." Please further explain your proposed actions. The NRC staff believes that the gaseous and liquid radioactive waste systems should be tested at high power when fission products are actually being created. Please provide additional justification for your proposed approach.

Westinghouse Response: (Revision 1)

1. Westinghouse will revise DCD subsection 14.2.10.4.2 as identified in the "**Design Control Document (DCD) Revision:**" portion of this RAI response to address the concern. As stated in DCD subsection 14.4.2, the Combined License applicant is responsible for providing test specifications and test procedures for the preoperational and startup tests. The procedures will meet the appropriate regulatory guidance. **Also, please refer to the associated Technical Specification Bases document, which provides further clarification that Technical Specification Section 3.2 core power distribution parameters include the NRC requested parameters of local surface heat flux, linear heat rate, departure from nucleate boiling and radial heat power peaking factors.**

2. Testing of the gaseous and liquid radioactive waste processing, storage, and release systems is performed at low power so that the negative impact of any system not performing as designed is minimal. The low power testing confirms that the systems performed as designed and therefore additional testing at high plant power is not necessary. This is consistent with other plants, for example, please see the Watts Bar or Vogtle FSAR.

   Westinghouse notes that because the radioactive sources in a nuclear power plant vary in isotopic and chemical makeup, and concentration; such variations include long term trends (e.g., due to gradual buildup of corrosion products over years of plant operation) and short term changes (e.g., due to fuel defect levels).

   The AP1000 radwaste systems remove radioactive material from the effluent streams via consumable media - charcoal and various resins for the liquid stream, and activated charcoal for the gaseous stream. This approach has been demonstrated to be effective in numerous operating plants, and calculated waste discharges using conservatively high source terms and conservatively low decontamination factors show discharges well within regulatory limits, as reported in DCD Chapter 11. Because of the use of consumable media the operator can make changes to the system to accommodate the changes in source term that will occur (e.g. replacing spent media with fresh media, adding a layer of ion-specific resin to general purpose resin beds, and so forth.)

   The specific performance of the radwaste systems is a complex issue, with the outcome determined by the interaction of varying source terms with variable radwaste system performance. Therefore, monitoring of system performance is essential, and such monitoring is done continuously, as described in DCD sections 11.2.1.2.4, 11.3.3, and 11.5.3.

   The complexity of the interaction between radwaste source terms and system performance limits the value of testing the system during the power ascension tests. Instead, low power testing confirms that system equipment (i.e. pumps, valves, etc.)

perform as expected, and the aforementioned continuous monitoring constitutes continuous testing and verification of adequate system purification performance.

Design Control Document (DCD) Revision: (Revision 1)

The following changes will be made to Rev. 3 of the DCD:

Change the second bullet under Test Method, of subsection 14.2.10.4.2 Incore Instrumentation System to read as follows:

Use data from the incore maps to verify that core power distribution is consistent with design predictions and the limits imposed by the plant Technical Specifications, and to calibrate other plant instrumentation. **Refer to Technical Specifications Section 3.2, Power Distribution Limits.**

PRA Revision: (Revision 1)

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 281.001 (Response Revision 1)

Question:

RG 1.54, Revision 1, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants," July 2000, defines the protective coatings-based service levels and the effect of coating failures on equipment during normal and post-accident conditions as delineated in the referenced ASTM standards. The use of the terms "safety-related" and "non-safety-related" are not used in this revision to RG 1.54 to classify coatings. Please clarify which of the coatings listed in Table 6.1-2 meet the definitions of Service Levels I, II, and III. (Section 6.1)

NRC Additional Comment:

In Section 6.1.2.1.6 of the markup of DCD Section 6.1 attached to the response to this question, the title of Regulatory Guide 1.54, Revision 1, is listed as "Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants." The correct title of Regulatory Guide 1.54, Revision 1, is "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants." This change needs to be made before the actual DCD changes are made.

Westinghouse Revised Response:

Revision 0 to this response updated DCD Section 6.1, and this markup was incorporated in DCD Revision 3. The NRC additional comment will be incorporated in the next revision of the DCD as shown in the attached markup.

Design Control Document (DCD) Revision:

DCD Revision 3 will be revised as shown.

DCD Section 6.1.2.1.6 is revised as follows:

6.1.2.1.6 Quality Assurance Features

A number of quality assurance features provide confidence that the coating systems inside the containment, on the exterior of the containment vessel and in potentially contaminated areas outside containment will perform as intended. These features enhance the ALARA program and enhance corrosion resistance. The features are discussed in the following paragraphs.

Service Level I and Service Level III Coatings

The quality assurance program for Service Level I and Service Level III coatings conforms to the requirements of ASME NQA-1-1983 as endorsed in Regulatory Guide 1.28. Safety related coatings meet the pertinent provisions of 10CFR Part 50 Appendix B to 10CFR Part 50. The service level classification of coatings is consistent with the positions given in Revision 1 of Regulatory Guide 1.54, " **Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants** ." Service Level I and Service Level III coatings used in the AP1000 are tested for radiation tolerance and for performance under design basis accident conditions. Where decontaminability is desired, the coatings are evaluated for decontaminability. The coating applicator submits and follows acceptable procedures to control surface preparation, application of coatings and inspection of coatings. The painters are qualified and certified, and the inspectors are qualified and certified.

DCD Table 1.9-1 is revised as follows:

Table 1.9-1 (Sheet 5 of 15)

REGULATORY GUIDE/DCD SECTION CROSS-REFERENCES

	Division 1 Regulatory Guide	DCD Chapter, Section or Subsection
1.53	Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems (Rev. 0, June 1973)	7.1 7.2 7.4 15.2 15.3 15.4 15.5 15.6
1.54	**Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants (Rev. 1, July 2000)**	6.1.2
1.55	Withdrawn	
1.56	Maintenance of Water Purity in Boiling Water Reactors (Rev. 1, July 1978)	This regulatory guide is not applicable to AP1000.
1.57	Design Limits and Loading Combinations for Metal Primary Reactor Containment System Components (Rev. 0, June 1973)	3.8.2 3.8.3
1.58	Withdrawn	
1.59	Design Basis Floods for Nuclear Power Plants (Rev. 2, August 1977)	2.4 3.4
1.60	Design Response Spectra for Seismic Design of Nuclear Power Plants (Rev. 1, December 1973)	2.5 3.7.1

PRA Revision:

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 410.005 (Response Revision 1)

Question:

(Section 5.2.5) AP1000 DCD, Section 5.2.5.3 indicates that the N_{13}/F_{18} radioactivity monitor can detect an 0.5 gallon-per-minute (gpm) leak when the plant is above 20 percent power. The detection sensitivity (0.5 gpm) is a function of the primary coolant radioactivity. Section 11.1 of the DCD discusses two source terms for the primary coolant: a conservative design-basis source term and a realistic source term. Please clarify which source term was assumed to determine the detection sensitivity of 0.5 gpm for the N_{13}/F_{18} radioactivity monitor. How can the assumption be verified with respect to the actual operating primary coolant radioactivity to assure the detection sensitivity of 0.5 gpm.

Position C.6 of RG 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems," states that the response time of each leakage detection system should be adequate to detect a leak rate of 1 gpm, or its equivalent, in less than one hour. What is the response time for the N_{13}/F_{18} radioactivity monitor? Demonstrate the adequacy of this response time in meeting RG 1.45, Position C.6, and in supporting leak-before-break (LBB) for the AP1000.

Westinghouse Response:

The production of N_{13}/F_{18} in the reactor coolant is a predictable function of core power, and is independent of primary coolant source term. F_{18} and N_{13} are produced by the radiolysis of oxygen atoms of the water of the reactor coolant, through the reactions:

$O_{16}(p, \alpha)\ N_{13}$, and
$O_{18}(p, n)\ F_{18}$

The leakage detection monitor continuously pumps a stream of the containment atmosphere through its detectors and then returns that stream to the containment. Since the amount of F_{18} and N_{13} produced in the coolant is a direct function of core power, and other parameters are fixed (e.g., containment volume), the level of F_{18} and N_{13} in the containment atmosphere will be a direct function of the leakage of coolant into the containment.

Design Control Document (DCD) Revision:

None

PRA Revision:

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

NRC Additional Comments:

The response has not address the following portion of the RAI:

Position C.6 of RG 1.45 states that the response time of each leakage detection system should be adequate to detect a leak rate of 1 gpm, or its equivalent, in less than one hour. What is the response time for the N_{13}/F_{18} radioactivity monitor? Demonstrate the adequacy of this response time in meeting RG 1.45, Position C.6 and in supporting leak-before-break (LBB) for the AP1000.

Westinghouse Additional Response:

The N_{13}/F_{18} radioactivity monitor can detect a 0.5 gallon-per-minute (gpm) leak within one hour when the plant is at full power.

Design Control Document (DCD) Revision:

DCD Revision 4 will include the clarification of adding "within one hour" as well as removal of some redundant and outdated text, as shown in the attached markup.

PRA Revision:

None

Identified leakages are monitored (using the reactor coolant drain tank) to calculate a leakage rate and by monitoring the intersystem leakage. The unidentified leakage rate is then calculated by subtracting the identified leakage rate from the total reactor coolant system leakage rate.

Since the pressurizer inventory is controlled during normal plant operation through the level control system, the level in the pressurizer will be reasonably constant even if leakage exists. The mass contained in the pressurizer may fluctuate sufficiently, however, to have a significant effect on the calculated leak rate. The pressurizer mass calculation includes both the steam and water mass contributions.

Changes in the reactor coolant system mass inventory are a result of changes in liquid density. Liquid density is a strong function of temperature and a lesser function of pressure. A range of temperatures exists throughout the reactor coolant system all of which may vary over time. A simplified, but acceptably accurate, model for determining mass changes is to assume all of the reactor coolant system is at $T_{Average}$.

The inventory balance calculation is done by the data display and processing system with additional input from sensors in the protection and safety monitoring system, chemical and volume control system, and liquid radwaste system. The use of components and sensors in systems required for plant operation provides conformance with the regulatory guidance of position 6 in Regulatory Guide 1.45 that leak detection should be provided following seismic events that do not require plant shutdown.

5.2.5.3.3 Containment Atmosphere Radioactivity Monitor

Leakage from the reactor coolant pressure boundary will result in an increase in the radioactivity levels inside containment. The containment atmosphere is continuously monitored for airborne gaseous radioactivity. Air flow through the monitor is provided by the suction created by a vacuum pump. Gaseous N_{13}/F_{18} concentration monitors indicate radiation concentrations in the containment atmosphere.

N_{13} and F_{18} are neutron activation products which are proportional to power levels. An increase in activity inside containment would therefore indicate a leakage from the reactor coolant pressure boundary. Based on the concentration of N_{13}/F_{18} and the power level, reactor coolant pressure boundary leakage can be estimated.

~~The N_{13}/F_{18} monitoring system will detect a 0.5 gpm leak when the reactor is operating at a power range higher than 20 percent.~~ The N_{13}/F_{18} monitor is seismic Category I. Conformance with the position 6 guidance of Regulatory Guide 1.45 that leak detection should be provided following seismic events that do not require plant shutdown is provided by the seismic Category I classification. Safety-related Class 1E power is not required since loss of power to the radiation monitor is not consistent with continuing operation following an earthquake.

~~At full power, the minimum detectable leak is 0.082 gpm when the radionuclide concentration in containment reaches equilibrium.~~ The N_{13}/F_{18} monitor is operable ~~can detect a 0.5 gpm leak~~ when the plant is above 20 percent power, and can detect a 0.5 gpm leak within one hour when the plant is at full power ~~and the concentration of radiogas in containment is at equilibrium~~.

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 410.016 (Response Revision 1)

Question:

The second paragraph of Section 9.1.3.4.3 "Abnormal Conditions," states that, in the unlikely event of an extended loss of normal spent fuel pool (SFP) cooling, a water level is maintained above the spent fuel assemblies for at least 7 days and that the amount of makeup required to provide the 7 day capability depends on the decay heat level of the fuel in the SFP and is provided "when the calculated decay heat level in the spent fuel pool is less than 2.3 MWt [megawatts thermal], no make up is needed to achieve spent fuel pool cooling for at least 7 days."

Please describe the mechanism that the operator will use to determine the thermal power level in the SFP. For example, if the calculated decay heat level in the SFP is 2.4 MWt, how would the operator know? Are means provided for the operator to read this value in the control room? Will the operator be required to perform the calculation?

Follow-On Comment:

The NRC staff would like to know how the operator would know to take action to provide makeup to the spent fuel pool.

Westinghouse Response (Revision 1):

Calculated power levels in the spent fuel pool, as provided in the AP1000 DCD, are used to determine the bases for availability requirements for spent fuel pool makeup water sources (LCO 3.7.9 in DCD Chapter 16, Technical Specifications). These power levels in conjunction with minimum water level/volume in the makeup tanks are used in calculations to show that sufficient on-site water is available to maintain the spent fuel pool water level above the spent fuel assemblies for at least 7 days. Calculation of spent fuel pool heat load is only required when taking makeup water sources out of service. The heat load in the spent fuel pool is calculated with the output from the temperature and flow instrumentation in the spent fuel pool cooling system. This heat load is calculated by the plant control system and is available to the operator in the control room.

In the event of an extended loss of spent fuel pool cooling the water in the pool will start to boil and the pool water level will drop. The operator will know that makeup water is required in the spent fuel pool as the result of alarms in the main control room based on spent fuel pool level. Both low level and low-low level alarms are provided by safety related level instrumentation in the spent fuel pool.

AP1000 DCD Section 9.1.3.4.3 will be modified to include a discussion of how the operator knows when to provide makeup water to the spent fuel pool.

Design Control Document (DCD) Revision:

From DCD Revision 3, page 9.1-17:

9.1.3.4.3 Abnormal Conditions

The AP1000 spent fuel pool cooling system is not required to operate to mitigate design basis events. In the event the spent fuel pool cooling system is unavailable, spent fuel cooling is provided by the heat capacity of the water in the pool. Connections to the spent fuel pool are made at an elevation to preclude the possibility of inadvertently draining the water in the pool to an unacceptable level.

In the unlikely event of an extended loss of normal spent fuel pool cooling, **the water in the pool will begin to boil and the water level will drop. Low spent fuel pool level alarms in the control room will indicate to the operator the need to initiate makeup water to the pool. These alarms are provided from safety related level instrumentation in the spent fuel pool. With the use of makeup** water **the pool** level is maintained above the spent fuel assemblies for at least 7 days. Initial spent fuel pool water level is controlled by technical specifications. During the first 72 hours any required makeup water is supplied from safety related sources. If makeup water beyond the safety related sources is required between 72 hours and 7 days, water from the passive containment cooling system ancillary water storage tank is provided to the spent fuel pool. The amount of makeup required to provide the 7 day capability depends on the decay heat level of the fuel in the spent fuel pool and is provided as follows:

- When the calculated decay heat level in the spent fuel pool is less than 2.3 MWt, no makeup is needed to achieve spent fuel pool cooling for at least 7 days.

- When the calculated decay heat level in the spent fuel pool is greater than or equal to 2.3 MWt and less than or equal to 2.8 MWt, safety related makeup from the cask washdown pit is sufficient to achieve spent fuel pool cooling for at least 7 days. A minimum level of 13.75 feet in the cask washdown pit is provided for this purpose. Availability of the makeup source is controlled by technical specifications.

- When calculated decay heat level in the spent fuel pool is greater than 2.8 MWt makeup from the passive containment cooling water storage tank or passive containment cooling ancillary water storage tank, or combination of the two tanks, is sufficient to achieve spent fuel pool cooling for at least 7 days.

- When the decay heat level in the reactor is less than 9 MW, the passive containment cooling water storage tank is not needed for containment cooling and this water can be used for makeup to the spent fuel pool. This tank provides safety related makeup for at least 72 hours. Between 72 hours and 7 days the tank continues to provide makeup water as required until it is empty. If the passive containment cooling water storage tank empties in less than 7 days, non-safety makeup water can be provided from the passive containment cooling ancillary water storage tank.

- When the decay heat level in the reactor is greater than 9 MW, the water in the passive containment cooling water storage tank is reserved for containment cooling. Safety related spent fuel pool cooling is provided for at least 72 hours from the pool itself and makeup water from the cask washdown pit. After 72 hours, non-safety related makeup can be provided from the passive containment cooling ancillary water storage tank.

- Minimum volume in the passive containment cooling water storage tank for spent fuel pool makeup is 755,000 gallons. Availability of this makeup source for the first 72 hours is controlled by technical specifications. Minimum volume in the passive containment ancillary water storage tank for spent fuel pool makeup is 175,000 gallons.

Table 9.1-4 provides the calculated timing and spent fuel pool water levels for several limiting event scenarios which would require makeup to the spent fuel pool.

PRA Revision:

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 410.018 (Response Revision 1)

Question:

Section 9.1.3.4.3.4, "Station Blackout," states that water vapor that evaporates from the surface of the SFP is vented to the outside environment through an engineered relief panel. This vent path maintains the fuel handling area at near atmospheric pressure conditions. Activity releases due to pool boiling are analyzed. Please discuss the method of analyzing the releases and provide details describing exactly how the activity is captured for analysis.

Follow-On Comments:

The NRC staff did not understand what Westinghouse intends with respect to the analysis of activity releases due to spent fuel pool boiling.

Westinghouse Response (Revision 1):

In DCD section 9.1.3.4.3.4 the sentence "Activity releases due to pool boiling are analyzed" is referring to an analytical calculation to predict the doses **if** boiling of the spent fuel pool **occurs, not an analysis of a grab sample during the event.**

The predicted doses resulting from spent fuel pool boiling are included in DCD Chapter 15. See the response to RAI 470.007 for the inputs and assumptions that are used in this calculation of expected doses resulting from boiling of the spent fuel pool. For each design basis accident in which doses are calculated and a loss of off-site power is assumed, there is a DCD section in which the doses resulting from both the accident and from boiling of the spent fuel pool are given. For example, see DCD section 15.1.5.4.6 for the calculated doses resulting from the steam line break and spent fuel pool boiling.

DCD section 9.1.3.4.3.4 will be modified to clarify that an evaluation is performed to predict the doses resulting from spent fuel pool boiling.

Design Control Document (DCD) Revision:

From DCD Revision 3, page 9.1-19:

9.1.3.4.3.4 Station Blackout

Following a loss of ac power (off-site power and both standby diesel generators), the heat capacity of the water in the pool is such that cooling of the fuel is maintained. Table 9.1-4 provides the times before boiling would occur in the pool following station blackout for various scenarios as well as the minimum

levels of water that would be reached. Water vapor that evaporates from the surface of the spent fuel pool is vented to the outside environment through an engineered relief panel. This vent path maintains the fuel handling area at near atmospheric pressure conditions. **The doses resulting from spent fuel pool boiling have been calculated and are included in Chapter 15.** The release concentrations at the site boundary are small fractions of the limits specified in 10 CFR 20, Appendix B with no credit for removal of activity by building ventilation systems (which are not available during loss of ac power situations). The equipment in the fuel handling area, rail car bay\filter storage area, and spent resin equipment and piping areas exposed to elevated temperature and humidity conditions as a result of pool boiling does not provide safety-related mitigation of the effects of spent fuel pool boiling or station blackout. The fuel handling area, rail car bay, and spent resin area do not have connecting ductwork with other areas of the radioactively controlled area of the auxiliary building and connecting floor drains have a water seal which prevents steam migration. The environment in these other areas during spent fuel pool steaming is mild with respect to safety-related equipment qualification and affords access for post-accident actions.

PRA Revision:

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 420.005 (Response Revision 1)

Question:

420.5 (DCD 7.1.3.3)

DCD 7.1.3.3 states that each soft control device can control safety-related and nonsafety-related equipment. Describe how the soft control devices interface with the redundant safety-related components. What type of safeguard in the design can prevent unauthorized or erroneous data entry into the protection system? Discuss the qualification process for the soft control device.

Westinghouse Response:

The citation above refers to the nonsafety-related soft control devices provided by the Data Display and Processing System (DDS). The DDS soft controls can be used to operate components in either the nonsafety-related Plant Control Systems (PLS) or the safety-related Protection and Safety Monitoring Systems (PMS).

The real-time data network of the nonsafety-related DDS is interfaced with the four channels of the safety-related PMS through four independent, qualified channel gateways. These gateways electrically protect the PMS equipment from failures of the nonsafety DDS equipment.

Automatic PMS operation protects against improper DDS operation of PMS systems and components. Specifically, whenever protective setpoints are exceeded, PMS protection signals are prioritized to override manual inputs from the nonsafety-related soft controls so as to place the safety-related components in their safe states.

These control signals are validated by the safety system prior to action being taken. The validation either takes the form of logic that prevents inhibiting of an automatic safety function or confirmation of action with the operator where there is no automatic safety function. Further details are available in Appendix 4 of the Common Q Topical Report.

Unauthorized PMS command entries by soft control are limited by system login and security features. Unauthorized PMS data entries are prevented by system login and security features, as well as key locks, door alarms, and key lock switches on PMS equipment cabinets. Data updates and software changes will be made using either the PMS maintenance and test panel or a portable workstation using a specialized configuration tool. Safety system constants, variables, and/or setpoint data are not subject to change through the soft control devices. Therefore, erroneous data entry into the PMS from the nonsafety-related soft controls is not possible.

The qualification process for the non-safety soft control device will be based on standard Westinghouse processes for:

- Quality assurance
- Verification and validation of non-safety software
- Electrical & EMI testing

Design Control Document (DCD) Revision:

None

PRA Revision:

None

NRC Additional Comments:

Westinghouse states that the qualification process for the non-safety soft control device will be based on standard Westinghouse processes for:

- Quality assurance
- Verification and validation on non-safety software
- Electrical & EMI [electromagnetic interference] testing

Are these documents available for staff audit?

Westinghouse Additional Response:

The documents describing standard processes for Quality Assurance and Verification and Validation of non-safety software are available for audit. Electrical and EMI testing are project-specific. The staff reviewed example project documents during the I&C meetings held in Pittsburgh on March 5 and 6, 2003.

The Westinghouse processes address the requirements of the AP1000 project and applicable portions of the standards listed in DCD 7.1.4.2.

Design Control Document (DCD) Revision:

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 420.012 (Response Revision 1)

Question:

420.12 (DCD 7.1.7, item 7)

DCD 7.1.7, item 7, WCAP-15775, "AP1000 Instrumentation and Control Defense-in-Depth and Diversity Report," Section 4.10.2, states that the protection and monitoring system (PMS) provides both system-level and component-level manual means of actuating ESF functions, and the diverse actuation system (DAS) provides manual means of actuating selected ESF functions. To support manual ESF actuation, both the PMS and the DAS provide plant information to the operator. Identify all the PMS and the DAS system-level and component-level manual actuation devices for every ESF function and the related supporting indications to the operator.

Westinghouse Response:

The manually actuated functions of the Protection and Safety Monitoring System (PMS) are described in DCD Tier 1 Section 2.5.2 and DCD Tier 2 Sections 7.1.2 and 7.3. The operator can perform the manual operations as specified in DCD Tables 7.2-4 and 7.3-3 using non-safety soft controls available at the operator workstations. In addition, the PMS provides a minimum inventory of safety-related dedicated manual actuation controls for the system-level actuations as specified in Table 18.12.2-1. The PMS manual controls are located on the Dedicated Safety Panel in the Main Control Room.

DCD Table 7.5-1 provides a list of the post-accident monitoring variables that are provided to the operator. All the variables listed in Table 7.5-1 are available on the non-safety operator workstations. Selected variables, as indicated in Table 7.5-1, are also available on the safety-related Qualified Data Processing Subsystem (QDPS) subsystem of PMS. The QDPS is described in DCD Tier 2 Section 7.1.2.5. Status of the PMS-actuated equipment is also displayed by the QDPS. The minimum inventory of displays and alerts is listed in DCD Tier 1 Table 2.5.2-5 and DCD Tier 2 Table 18.12.2-1.

The manually actuated functions and supporting indications of the Diverse Actuation System (DAS) are described in DCD Tier 1 Section 2.5.1 and DCD Tier 2 Section 7.7.1.11. Dedicated manual actuation controls are provided for the functions specified in DCD Tier 1 Table 2.5.1-2. DAS sensors and displays are listed in DCD Tier 1 Table 2.5.1-3 and described in DCD Tier 2 Section 7.7.1.11. The use of these indications to support diverse manual actuation is described in Section 7.7.1.11 under "Indication" on page 7.7-17. Status of the DAS-actuated equipment is not displayed by DAS, but rather by the post-accident monitoring system variables on QDPS; see Table 7.5-1.

Design Control Document (DCD) Revision:

None

PRA Revision:

None

NRC Additional Comments:

Westinghouse should update response to commit that hardwiring of DAS manual actuations is included as Tier 2*.

Westinghouse Additional Response:

Westinghouse agrees to commit that hardwiring of DAS manual actuations is included as Tier 2*.

Design Control Document (DCD) Revision:

Table 1-1
Index of AP1000 Tier 2 Information Requiring NRC Approval for Change

Item	Expiration at First Full Power	Tier 2 Reference
WCAP-13383, "AP600 Instrumentation and Control Hardware & Software Design, Verification & Validation Process Report," Rev 1.	Yes	Chapter 7 Table 1.6-1
WCAP-14605, "Westinghouse Setpoint Methodology for Protection Systems, AP600," Rev 0	Yes	Chapter 7 Table 1.6-1
CE-CES-195, "Software Program Manual for Common Q Systems," Rev 01	Yes	Chapter 7 Table 1.6-1
WCAP-15927, "Design Process for AP1000 Common Q Safety Systems," Rev 0	Yes	Chapter 7 Table 1.6-1
Verification and Validation	Yes	7.1.2.14
Conformance with Industry Standards	Yes	7.1.4.1.8

Item	Expiration at First Full Power	Tier 2 Reference
Hard-wired DAS manual actuation	No	7.7.1.11

7.7.1.11 Diverse Actuation System

Manual Actuation Function

[*The manual actuation function of the diverse actuation system is implemented by hard-wiring the controls located in the main control room directly to the final loads in a way that completely bypasses the normal path through the control room multiplexers, the protection and safety monitoring system cabinets and the diverse actuation system automatic logic.*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 420.022 (Response Revision 1)

Question:

420.22 (DCD 7.1.2.11)

The AP600 protection and safety monitoring system performs surveillance testing via a portable tester. Describe the provision provided for the AP1000 surveillance testing. Identify the tasks tested by a portable tester and the tasks tested by the built-in circuit in the protection cabinets.

Westinghouse Response:

Surveillance testing can be divided into three categories:

- On line Diagnostics Monitoring using AC 160 Platform features
- On line surveillance testing using built in test features
- Refueling Interval testing using an I/O simulator or similar device.

1. Automatic On-Line Diagnostics Monitoring

As defined in Section 6.4.1 of Reference 7.1.7.13, the Common Qualified Platform Topical Report, the AC 160 platform possesses an extensive set of on-line diagnostics. Automatic testing is an integral part of the Common Q system. It is used to monitor the integrity of the application as it performs its function. Diagnostics run continuously as background tasks during normal AC 160 operation. Any resulting errors are recorded in the processor log, and will provide appropriate alarms.

The status of failed modules is flagged to downstream components, and appropriate, conservative actions taken. The AC 160 platform is also equipped with both hardware and software watchdog timers. Fatal errors will result in a processor halt condition, and force a fail-safe watchdog timer timeout. In addition to processor tests, the AC 160 also verifies operation of the I/O modules, high-speed data-links and intra-channel AF100 bus communications

The AC 160 platform diagnostic tests are a background feature of the platform, and no separate internal or external-testing device is required.

2. Surveillance Testing

As described in Section 7.1.2.11, the Protection System function is tested by a series of overlapping tests, such that the entire protection system is verified, up to the final actuation device. This is under the control of the built in test features within the cabinet. Such testing includes four-channel comparison of input data and system setpoints. Other tests are

periodically performed in a manually initiated automatic test sequence, in which test details are not under direct operator control. These tests include verification of the operability of the various trip and interlocking functions, including two out of four trip logic, up to, but not including, the final actuated device. Some test features, such as opening of the reactor trip breakers would be under manual control only. In all cases, the test system provides suitable prompting and appropriate diagnostic messages. The combination of on-line diagnostics and automatic surveillance testing and monitoring greatly reduce the need for manual initiated surveillance testing during normal operation.

3. Refueling Interval testing using an I/O simulator or similar device.

The built in test features of the PMS are adequate to monitor the system during normal operation. However, periodically, it may be necessary to inject external signals into the PMS to verify system performance. An example of this is refueling interval response time verification and system testing following major maintenance. An input/output simulator or similar device is used in such situations to provide simulated inputs and monitor appropriate outputs.

Design Control Document (DCD) Revision:

None

PRA Revision:

None

NRC Additional Comments:

Westinghouse should clarify that a portable tester is not specified for AP1000.

Westinghouse Additional Response:

The test features described in the DCD and in the original response to this RAI are provided by the built-in test subsystem described in DCD subsection 7.1.2.11. A portable tester is not included in the AP1000 design.

Design Control Document (DCD) Revision:

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 440.048 (Response Revision 1)

Question:

Section 5.4.12.1 states that the reactor vessel head vent system (RVHVS) is designed to vent a volume of hydrogen at system pressure and temperature equivalent to approximately 40 percent of the RCS volume in one hour.

A. Describe the rationale for appropriateness of this vent capacity design basis.

B. Do the AP1000 RVHVS valves have individual positive valve position indication and alarm in the control room?

Westinghouse Response:

A. DCD Section 5.4.12.1 states the reactor vessel head vent system is sized to vent a volume of hydrogen at system pressure and temperature equivalent to approximately 40% of the reactor coolant system volume in one hour. This is the traditional sizing basis for post Three Mile Island (TMI) reactor vessel head vent systems. However, since the AP1000 utilizes an automatic depressurization system (ADS), collecting of non-condensables in the RV head does not impede core cooling and therefore RV head venting capability is not required for AP1000.

The AP1000 RVHV capacity is also sized to perform the following functions:

- provide an emergency letdown path that can be used to prevent long-term pressurizer overfill following loss of heat sink events.
- normal RCS venting and filling operations during startup.

The limiting requirement is providing an emergency letdown path to prevent long term pressurizer overfill. Capacity of the RVHVS is confirmed by ITAAC 8.e.

From AP1000 ITAACs (DCD Section 2.1.3, Table 2.1.2-4:

8.e) The RCS provides emergency letdown during design basis events.	Inspections of the reactor vessel head vent valves and inlet and outlet piping will be conducted.	A report exists and concludes that the capacity of the reactor vessel head vent is sufficient to pass not less than 8.2 lbm/sec at 1250 psia in the RCS.

B. The AP1000 remotely-operated, safety-related valves, which includes the RVHVS valves (RCS-PL-V150A, B, C, D), have individual positive valve position indication in the Main Control Room. Design of the AP1000 alarm system is part of the HSI design process described in DCD chapter 18.

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

Design Control Document (DCD) Revision:

None

PRA Revision:

None

NRC Additional Comments:

In RCS ITAAC Table 2.1.2-4, the Acceptance Criterion for Design Commitment Item 8.e, (i.e., the RCS provides emergency letdown via the reactor vessel head vent system during design basis events to prevent long term pressurizer overfill) is that the capacity of the reactor vessel head vent is sufficient to pass not less than 8.2 lbm/sec at 1250 psia in the RCS. This acceptance criterion is the same as AP600.

Explain how this criterion is derived. Is it calculated from the RVHVS's venting capacity design basis of vent 40% of the RCS volume in one hour?

The response to 440.049 states that the design bases for the head vent include the ability to relieve water from the RCS at a flow sufficient to prevent pressurizer overfill during an event where the mass addition from the core makeup tanks (CMTs) causes an increase in pressurizer inventory that otherwise might overfill the pressurizer.

What is the limiting transient for pressurizer overfill? What is the rate of insurge into the pressurizer? Is ITAAC acceptance criterion of 8.2 lbm/sec corresponding to this insurge rate?

Westinghouse Revised Response:

A. Design Basis for RVHVS Capacity

As described in the response to Rev. 0 of this RAI, since the AP1000 utilizes an automatic depressurization system (ADS), collecting of non-condensables in the RV head does not impede core cooling and therefore there are no requirements on RV head non-condensable venting capability.

The AP1000 RVHV capacity is sized to perform the following functions:

- provide an emergency letdown path that can be used to prevent long-term pressurizer overfill following loss of heat sink events.
- normal RCS venting and filling operations during startup.

The limiting requirement is to provide an emergency letdown path to prevent long term pressurizer overfill.

The sizing of the RVHV system has been based on the consideration related to the long term pressurizer overfilling.

Since AP600 venting capacity was found to be in excess with respect to the requirements posed by the consideration related to the pressurizer overfilling, and considering that the AP1000 plant, with respect to the AP600, is equipped with a much larger pressurizer, that makes the overfilling transients less severe, it was decided to evaluate the possibility to use, for the AP1000, the same RVHV system design already developed for the AP600.

The adequacy of the RVHV system sizing has been confirmed by a number of transient analyses performed to show that, even considering the most adverse combination of initial conditions and assumptions, the RVHV capacity defined for the AP600 plant is enough to avoid pressurizer overfilling.

B. Most Limiting Transients for Pressurizer Overfilling

The most limiting transients that could potentially results in a pressurizer overfilling are the transients presented in the Chapter 15.5 of the DCD. In particular, analyses have shown that the limiting transient is the "Chemical and Volume Control System Malfunction That Increases Reactor Coolant System Inventory".

Table 1 below shows the time to overfilling for the transients analyzed in Chapter 15.5 of the AP1000 DCD.

TABLE 1

AP1000 Pressurizer Overfilling Limiting Transients

	Accident	Time to Overfill from Accident Initiation (seconds)	Time to Overfill from Reactor Trip (seconds)
1	Spurious "S" Signal	6,185	6,185
2	Inadvertent Operation of the Core Makeup Tanks During Power Operation	4,674	3,717
3	Chemical and Volume Control System Malfunction That Increases Reactor Coolant System Inventory	4,716	2,926

Analyses performed for all of the above transients, using the AP1000 RVHV system demonstrate that:

- For the Spurious "S" more than 1 hour is available for the operator to open the RVHV valves to avoid overfilling. Assuming operator action 1 hour after the "S" signal there is still a margin of about 150 ft^3 to overfilling.
- For the Inadvertent Operation of the Core Makeup Tanks During Power Operation, assuming a very conservative behavior of the injection flow rate from the broken CMT,

more than 50 minutes are still available for the operator to open the RVHV valves to avoid overfilling. Assuming operator action 50 minutes after the "S" signal there is still a margin of more than 60 ft^3 to overfilling.

- For the Chemical and Volume Control System Malfunction That Increases Reactor Coolant System Inventory more than 45 minutes are available for the operator to open the RVHV valves to avoid overfilling. Assuming operator action 45 minutes after the "S" signal there is still a margin of approximately 7 ft^3 to overfilling. Assuming operator action 30 minutes after the "S" signal there is still a margin of 185 ft^3 to overfilling. In the following, the Chemical and Control System Malfunction That Increases Reactor Coolant System Inventory is discussed in detail. The worst CVS malfunction case, performed assuming 30 minutes delay for operator action from the reactor trip time, is presented.

Chemical and Control System Malfunction That Increases Reactor Coolant System Inventory

Under typical operating conditions for the AP1000, the boron concentration of the injected chemical and volume control system (CVS) water is equal to that of the reactor coolant system. If the CVS is functioning in this manner and the pressurizer spray system functions properly to prevent a high pressure reactor trip signal, no 'S" signals are generated and this specific event is also terminated by automatic isolation of the CVS on the safety-related high-2 pressurizer level setpoint.

If the automatic rod control is modeled and the pressurizer spray functions properly to prevent a high pressure reactor trip signal, no "S" signals are generated and this specific event is terminated by automatic isolation of the CVS on the safety-related high-2 pressurizer level setpoint.

At high CVS boron concentration, low reactivity feedback conditions, and reactor in manual rod control, an 'S" signal will be generated by either the low Tcold or low steamline pressure setpoints before the CVS can inject a significant amount of water into the reactor coolant system. In this case, the CVS malfunction event proceeds similarly to, and is only slightly more limiting than, a spurious "S" signal event.

The transient resulting from a RCS deboration is discussed in the DCD Chapter 15.4.6 "Chemical and Volume Control System Malfunction that Results in a Decrease in the Boron Concentration in the Reactor Coolant". With the reactor at power, under manual control, and assuming no operator action taken to terminate the transient, the power and temperature rise causes the reactor to reach the overtemperature ΔT trip setpoint resulting in a reactor trip. Upon any reactor trip signal, a safety-related function automatically isolates the unborated water from the demineralized water transfer and storage system and thereby terminates the dilution. Additionally, the suction lines for the CVS pumps are automatically realigned to draw borated water from the CVS boric acid tank. In this case, CMT would not be actuated and hence overfilling is not a concern.

While these scenarios are the most probable outcomes of a CVS malfunction, several combinations of boron concentration, feedback conditions, and plant system interactions have been identified which can result in more limiting scenarios with respect to pressurizer overfill. The key factors, that make this event more limiting than a spurious "S" signal event, are that the reactor coolant system is at a lower average temperature, higher pressure, and a higher pressurizer level at the time an "S" signal is generated. These factors produce a greater volume of higher density water and, thus, a larger reactor coolant system mass at the time of the "S" signal. In addition, at lower reactor coolant system average temperature, the PRHR is less effective in removing decay heat, which results in greater expansion of the cold water injected by the core makeup tanks.

Under the worst possible conditions, this transient can result in the pressurizer overfilling in about 80 minutes from the initiation of the accident. Nevertheless, the combination of the initial conditions and assumptions taken to analyze this worst case are almost unrealistic. In fact, boron concentration of the CVS flow is evaluated to result in RCS boration such that, assuming the power control system not operable, the decrease in core power level and RCS coolant temperature results in a reactor trip signal on a Low Tcold "S" at the same time the pressurizer level reaches the CVS isolation setpoint. This assumption results in the immediate actuation of the CMTs that provides additional coolant inventory to the RCS.

The worst CVS Malfunction That Increases Reactor Coolant System Inventory event is presented hereafter, both with and without assuming operator actions, to demonstrate that the sizing of the RVHVS is adequate for avoiding the long term pressurizer overfilling.
The main assumptions for the case analyzed are the following:

- Boron Concentration evaluated to reach the Hi-2 PRZ Level at the time the Low-Tcold Signal is reached
- Minimum PRHR safeguards (lower heat transfer capability)
- Maximum CMTs safeguards (higher injection rates)
- No automatic power control
- Pressure control available

In addition, a number of parameters have been defined, via sensitivity studies, to provide the worst initial plant conditions. Those include the following:

- Minimum PRZ initial water volume (more time for reaching the Hi-2 pressurizer level)
- Maximum Tavg temperature (more time for reaching the Low Tcold)
- Maximum Initial PRZ Pressure

It should be noted, however, that since the condition at the time of the CVS isolation is fixed, in terms of RCS coolant volume (i.e., Hi-2 PRZ Level) and temperature at the cold leg (i.e., Low Tcold setpoint), the parameters above do not affect significantly the transient evolution.

The sequence of events for the worst cases analyzed is reported in Table 2.

The case assuming no operator action shows that overfilling occurs in about 80 minutes from the transient initiation (4716 seconds), Table 2. That is about 49 minutes from reactor trip actuation. Assuming operator action 45 minutes from the reactor trip signal (75 minutes from the accident initiation) the pressurizer does not overfill.

The time available to the operator to avoid overfilling is more than adequate also considering that, for the event analyzed, several alarms are immediately actuated to warn the operators.

Figure 1 through 9 show the behavior of the main plant parameters for the case with operator actions simulated. In particular, Figure 3 shows that there is an ample margin to PRZ overfilling that occurs at almost 2200. ft^3. Figure 5 shows the RVHV flow rate. The maximum flow rate is about 9 lb/s at a RCS pressure of 2500 psia. This mass flow is, at the time of operator action, a little bit lower than the pressurizer insurge (see Figure 6). However, due to the large free volume still available at the time the RVHV valve opens and due to the fact that mass input to the RCS quickly drops (see Figure 8 – CMT Injection and Balance Line Flow Rates) the pressurizer does not overfill .

Figure 10 shows the comparison of the behavior of the pressurizer water volume for the two cases (with and without operator action).
Figure 11 shows the comparison of the behavior of the RCS inventory for the two cases (with and without operator action).
Figure 12 shows the behavior of the pressurizer surge flow in the time window between 2,000 seconds (few minutes after the reactor trip) and 8,000 seconds for the cases analyzed. It is possible to notice that the expected surge flow is in the range between 15 and 12 lbm/s and decreases significantly with time. This figure and figure 6 show that, following the RVHV valves opening, the surge line flow rate immediately drops to about 3 lbm/s and eventually inverts (pressurizer outsurge).

These analyses demonstrate that, even for the worst combination of initial conditions and assumptions, and assuming concomitant failures (e.g., failure of one PRHR discharge valve concomitant with the failure of one RVHV valve), the sizing of the RVHV, combined with the sizing of the AP1000 pressurizer, is adequate to avoid long term pressurizer overfilling assuming operator actions starting 30 minutes from the reactor trip signal.

TABLE 2

With Operator Time (s)	Without Operator Time (s)	Time sequence of events: Event
10.0	10.0	Transient Started, Spurious "CVS" (one pump) start injecting borated water
1,800.9	1,800.9	"S" Signal - Low Tcold Setpoint (500 °F) reached
1,801.1	1,801.1	Hi-2 PRZ Level Setpoint 67% span (CVS Isolation) reached
1,802.9	1,802.9	Reactor Trip - RCCA insertion begins
1,802.9	1,802.9	Turbine Trip begins
1,805.6	1,805.6	Loss of offsite power and reactor coolant pumps start to coastdown
1,812.9	1,812.9	CVS, Main steam and feed lines are isolated – CMT Valves fully open
1,817.9	1,817.9	PRHR actuated on "S" signal (valve fully open)
2,032.0	2,032.0	Pressurizer safety valves open
3,603.0	3,603.0	Pressurizer Water Volume ≈30 minutes after RxT (1,962 ft^3)
3,603.0	-------	Operator Open RVHV valve
--------	4,726.0	Pressurizer Overfills
5,028	---------	Margin To Overfill (185.5 ft^3)
4,532	15,760.0	Pressurizer safety valves close
~15,200	~15,600.0	PRHR matches decay heat
~20,488.0	~21,344.0	Core makeup tanks stop recirculating (time at which BL flow goes to zero)

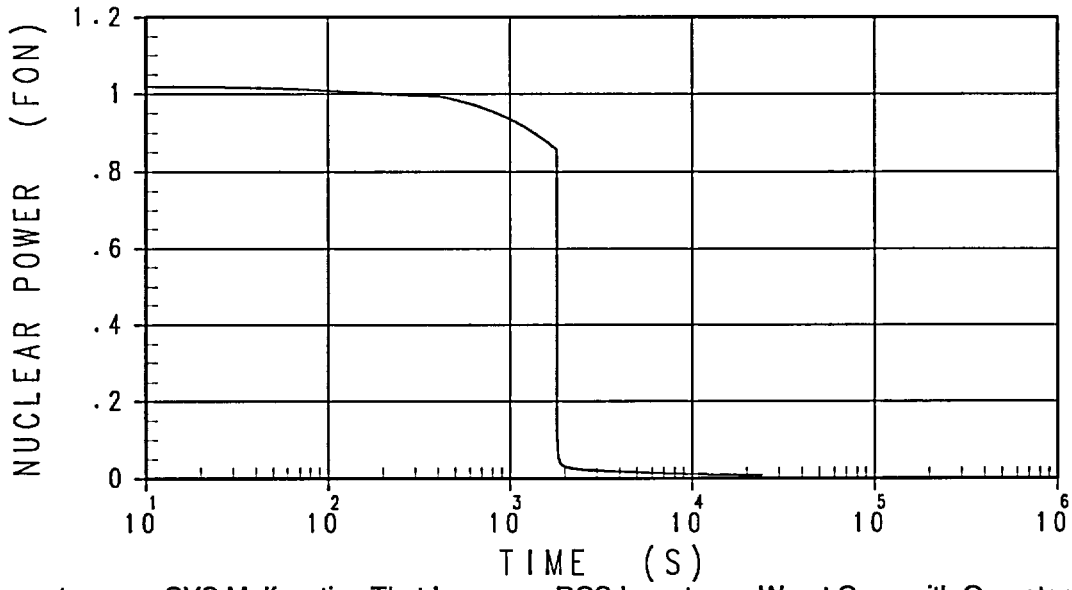

Figure 1. CVS Malfunction That Increases RCS Inventory – Worst Case with Operator Actions
Nuclear Power (f.o.n.) vs. Time

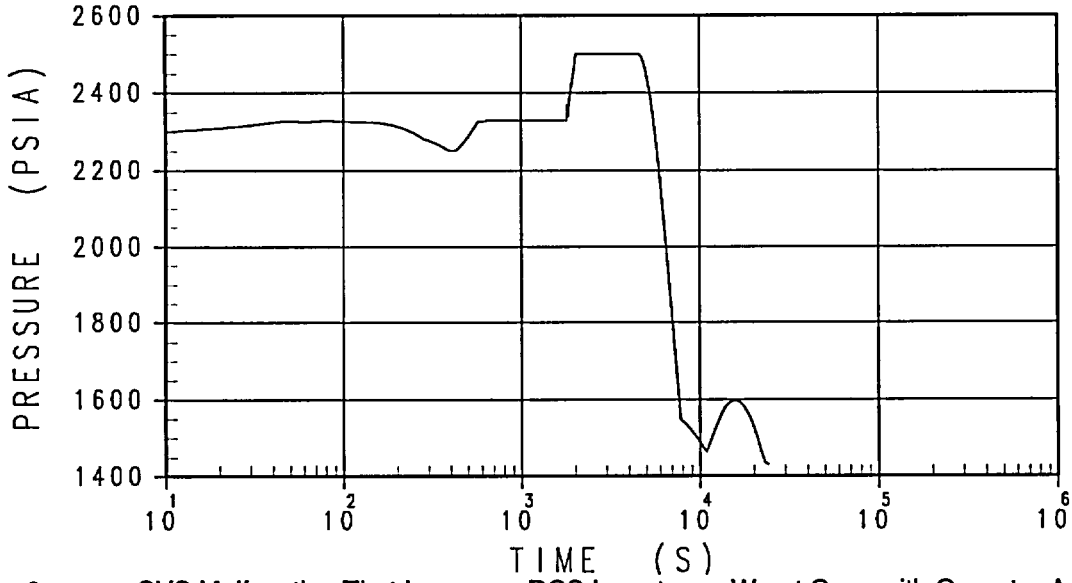

Figure 2. CVS Malfunction That Increases RCS Inventory – Worst Case with Operator Actions
Pressurizer Pressure (psia) vs. Time

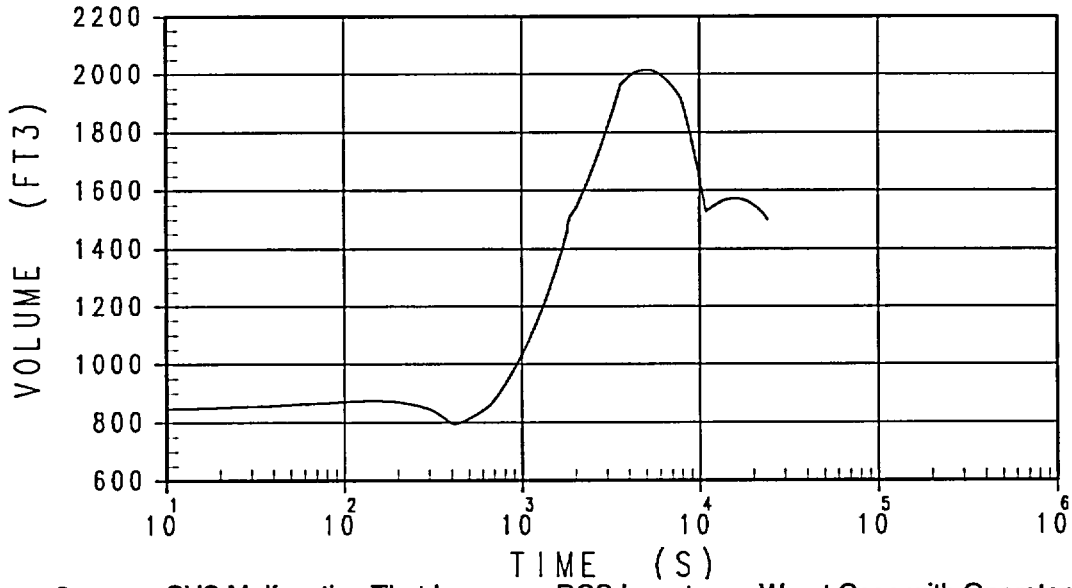

Figure 3. CVS Malfunction That Increases RCS Inventory – Worst Case with Operator Actions
Pressurizer Water Volume (ft^3) vs. Time

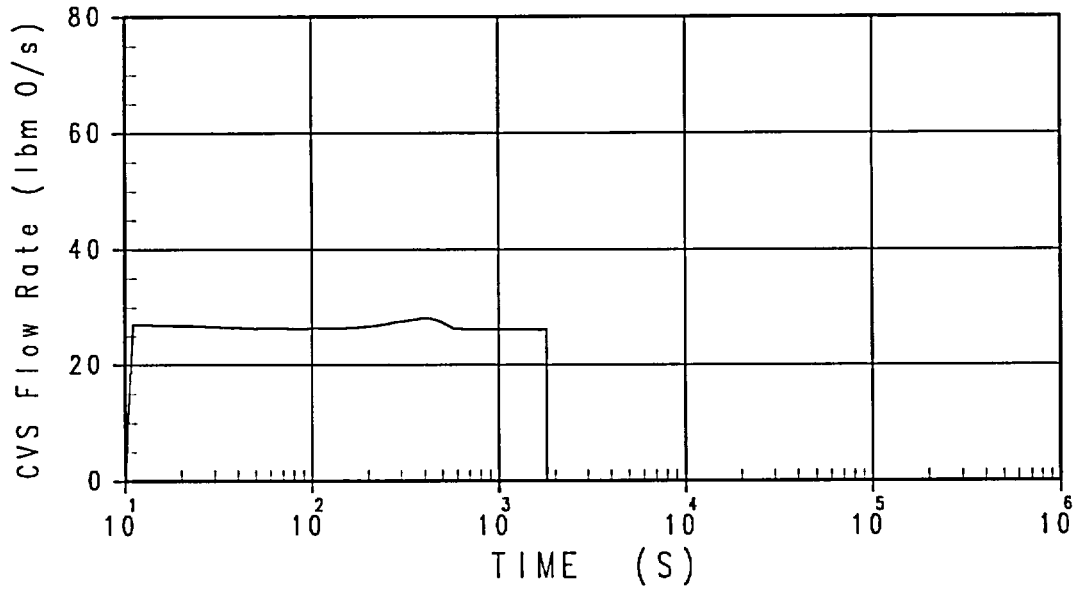

Figure 4. CVS Malfunction That Increases RCS Inventory – Worst Case with Operator Actions
CVS Injection Flow Rate (lbm/s) vs. Time

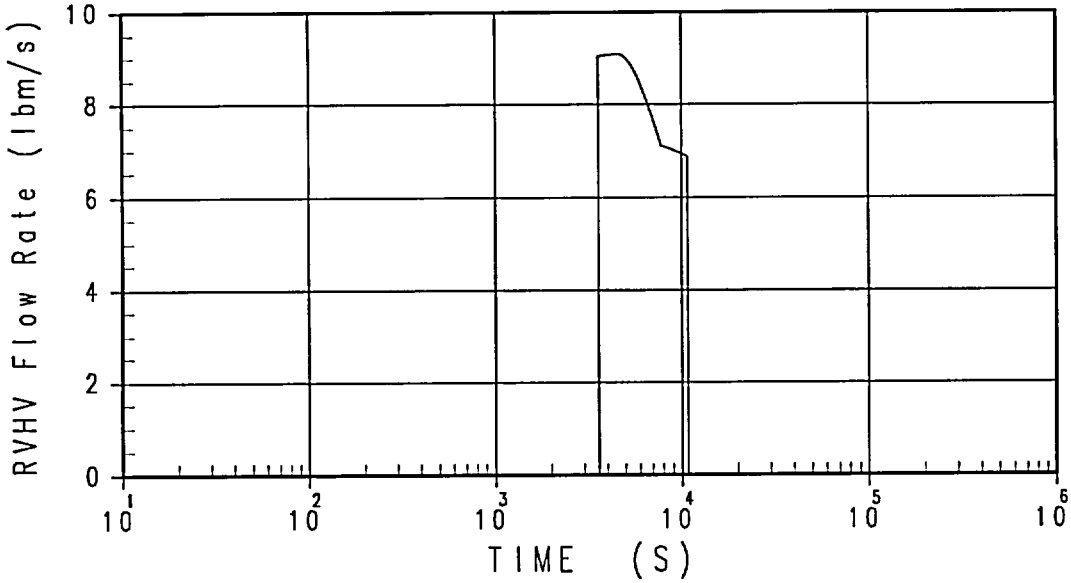

Figure 5. CVS Malfunction That Increases RCS Inventory – Worst Case with Operator Actions RVHV Flow Rate (lbm/s) vs. Time

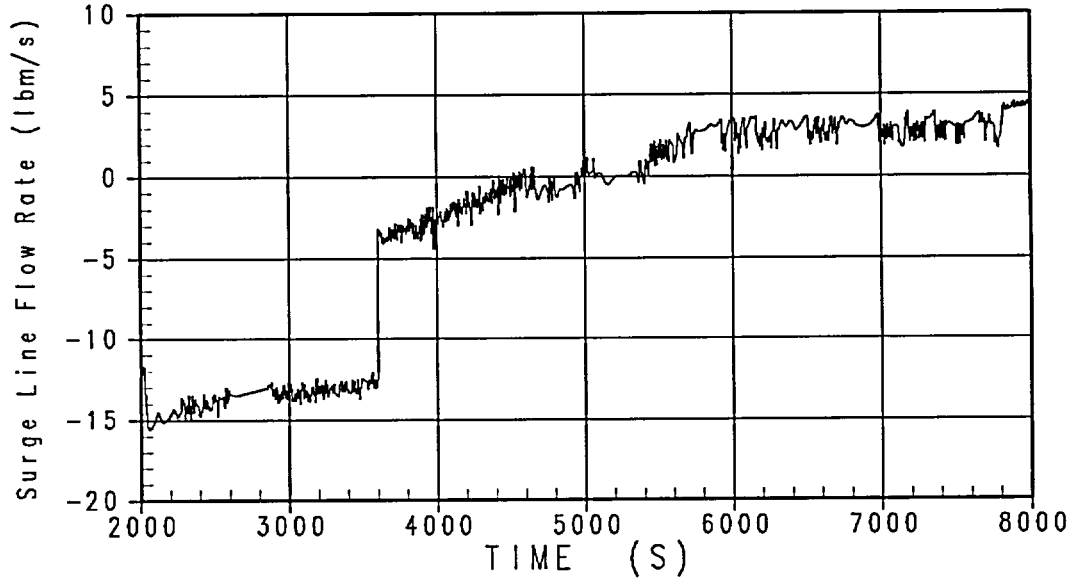

Figure 6. CVS Malfunction That Increases RCS Inventory – Worst Case with Operator Actions Surge Line Flow Rate (lbm/s) vs. Time

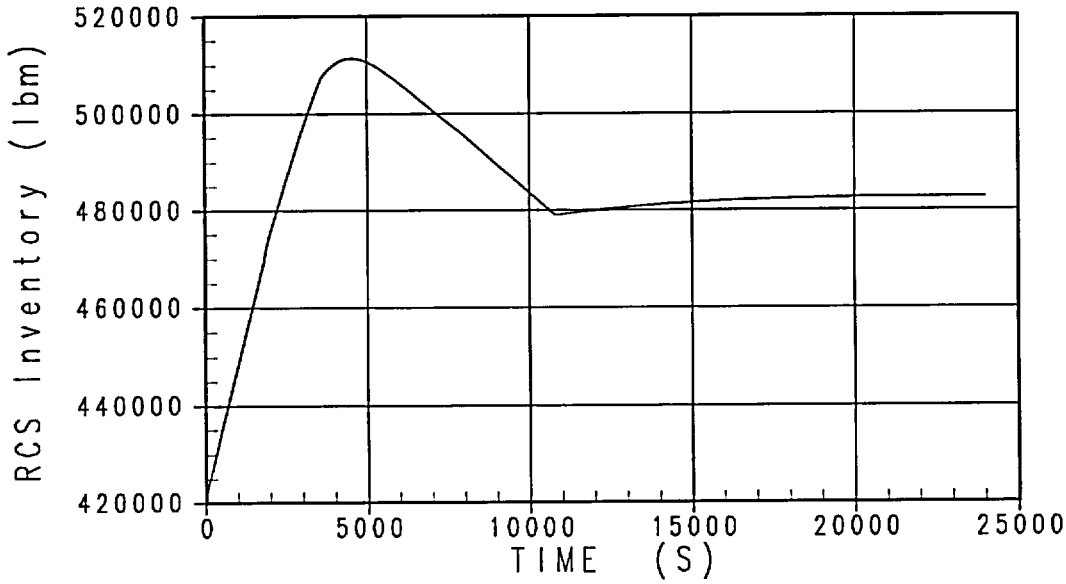

Figure 7. CVS Malfunction That Increases RCS Inventory – Worst Case with Operator Actions RCS Inventory (lbm) vs. Time

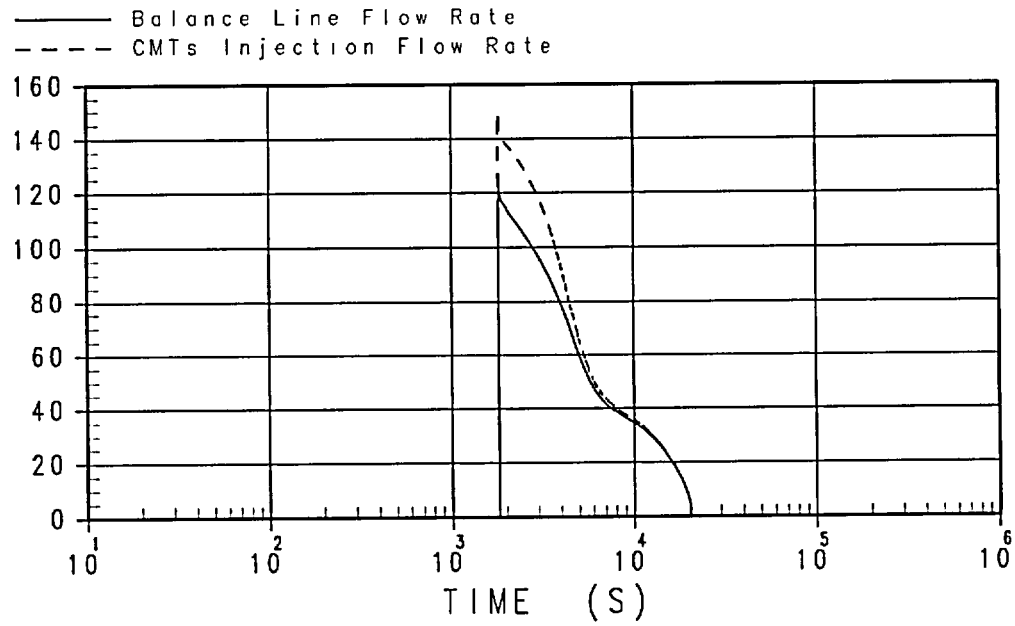

Figure 8. CVS Malfunction That Increases RCS Inventory – Worst Case with Operator Actions CMT Injection and Balance Line Flow Rate (lbm) vs. Time

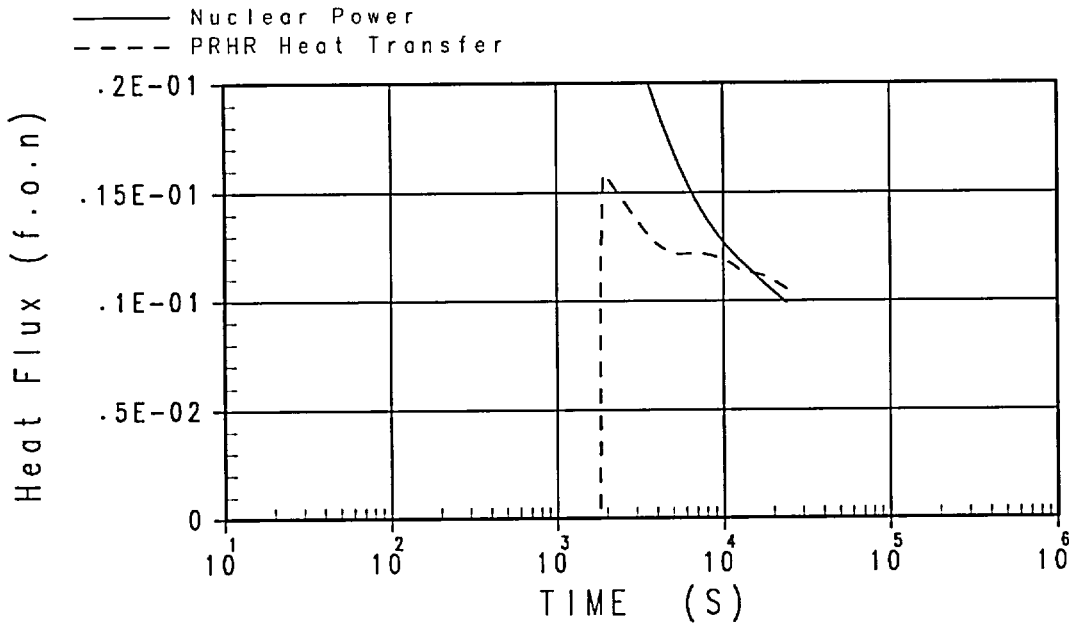

Figure 9. CVS Malfunction That Increases RCS Inventory – Worst Case with Operator Actions
Core Heat Flux and PRHR Heat Flux (f.o.n.) vs. Time
(with operator action)
(w/o operator action)

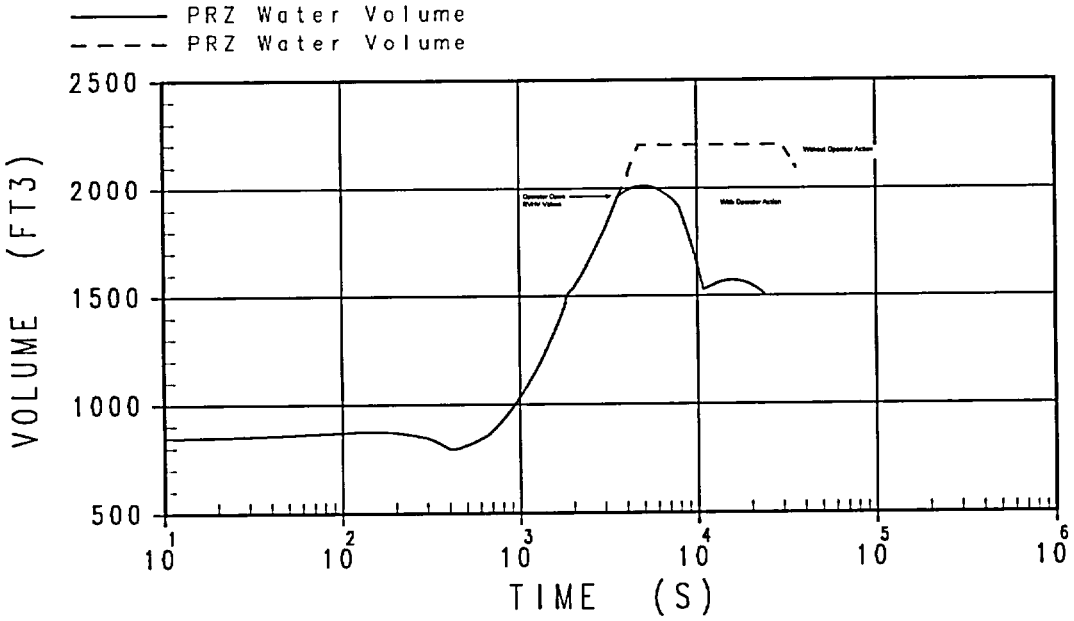

Figure 10. Comparison of Worst Case - With and Without Operator Actions
Pressurizer Water Volume (ft^3) vs. Time

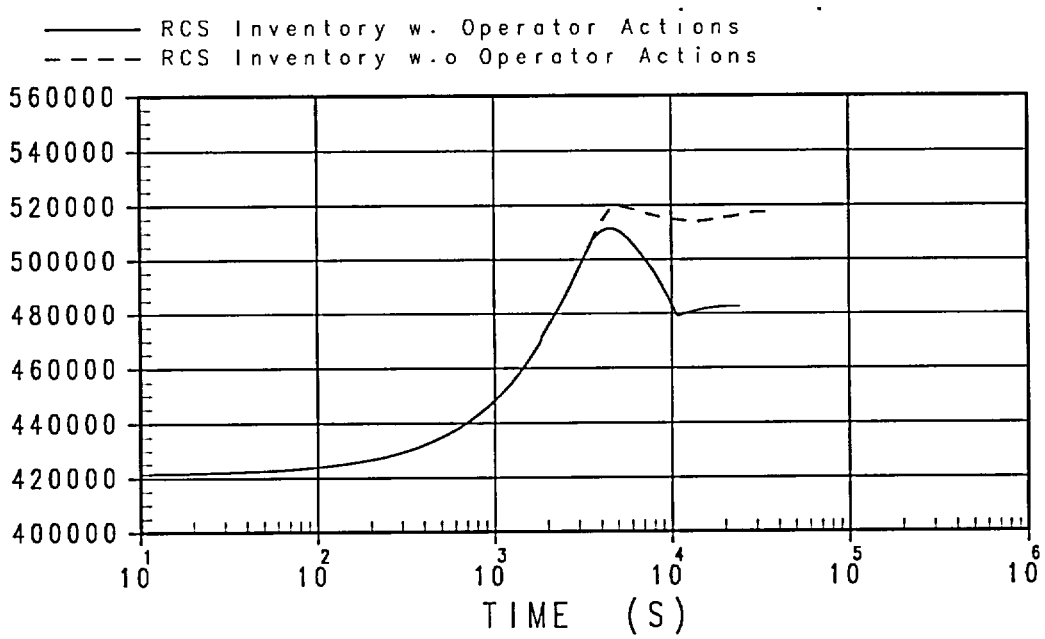

Figure 11. Comparison of Worst Case - With and Without Operator Actions RCS Inventory (lbm) vs. Time

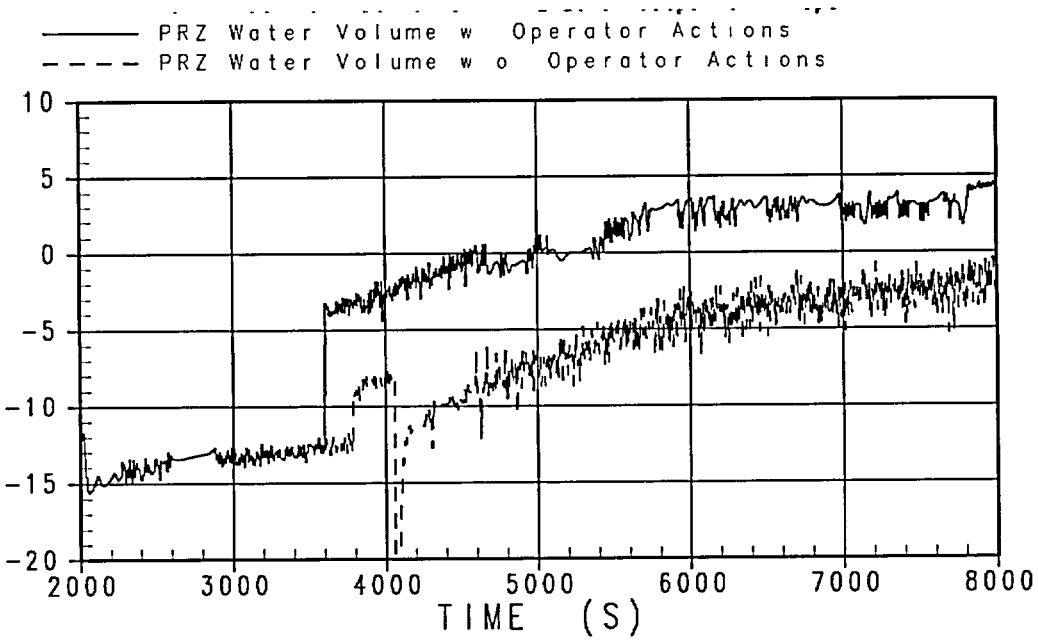

Figure 12. Comparison of Worst Case - With and Without Operator Actions Surge Line Flow Rate (lbm/s) vs. Time

Design Control Document (DCD) Revision:

Design Control Document Revision 3, Section 5.4.12 will be revised as shown to reflect the actual design criterion for the AP1000 Reactor Vessel Head Vent System.

5.4.12 Reactor Coolant System High Point Vents

The requirements for high point vents are provided for the AP1000 by the reactor vessel head vent valves and the automatic depressurization system valves. The primary function of the reactor vessel head vent is for use during plant startup to properly fill the reactor coolant system and vessel head. Both reactor vessel head vent valves and the automatic depressurization system valves may be activated and controlled from the main control room. The AP1000 does not require use of a reactor vessel head vent to provide safety-related core cooling following a postulated accident.

The reactor vessel head vent valves (Figure 5.4-8) can remove noncondensable gases or steam from the reactor vessel head to mitigate a possible condition of inadequate core cooling or impaired natural circulation through the steam generators resulting from the accumulation of noncondensable gases in the reactor coolant system. The design of the reactor vessel head vent system is in accordance with the requirements of 10 CFR 50.34 (f)(2)(vi).

The reactor vessel head vent valves can be operated from the main control room to provide an emergency letdown path which is used to prevent pressurizer overfill following long-term loss of heat sink events. An orifice is provided downstream of each set of head vent valves to limit the emergency letdown flow rate.

The first stage valves of the automatic depressurization system are attached to the pressurizer and provide the capability of removing noncondensable gases from the pressurizer steam space following an accident. Venting of noncondensable gases from the pressurizer steam space is not required to provide safety-related core cooling following a postulated accident. Gas accumulations are removed by remote manual operation of the first stage automatic depressurization system valves.

The discharge of the automatic depressurization system valves is directed to the in-containment refueling water storage tank. Subsection 5.4.6 and Section 6.3 discuss the automatic depressurization system valves and discharge system.

The passive residual heat removal heat exchanger piping and the core makeup tank inlet piping in the passive core cooling system include high point vents that provide the capability of removing noncondensable gases that could interfere with heat exchanger or core makeup tank operation. These gases are normally expected to accumulate when the reactor coolant system is refilled and pressurized following refueling shutdown. Any noncondensable gases that collect in these high points can be manually vented.

The discharge of the passive residual heat removal heat exchanger high point vent is directed to the in-containment refueling water storage tank. The discharge of the core makeup tank high point vent is directed to the reactor coolant drain tank. Section 6.3 discusses the passive residual heat removal heat exchanger and venting capability, which is part of the passive core cooling system.

5.4.12.1 Design Bases

The reactor vessel head vent arrangement is designed to remove noncondensable gases or steam from the reactor coolant system via remote manual operations from the main control room through a pair of valves. The system discharges to the in-containment refueling water storage tank (IRWST).

The reactor vessel head vent system is designed to provide an emergency letdown path that can be used to prevent long-term pressurizer overfill following loss of heat sink events. The reactor vessel head vent is designed to limit the emergency letdown flow rate to within the capabilities of the normal makeup system. **The reactor vessel head vent system can also vent noncondensable gasses from the reactor head in case of a severe accident.**

The system vents the reactor vessel head by using only safety-related equipment. The reactor vessel head vent system satisfies applicable requirements and industry standards, including ASME Code classifications, safety classifications, single-failure criteria, and environmental qualification.

The piping and equipment from the vessel head vent up to and including the second isolation valve are designed and fabricated according to ASME Codes Section III, Class 1 requirements. The remainder of the piping and equipment are design and fabricated in accordance with ASME Code, Section III, Class 3 requirements.

The supports and support structures conform with the applicable requirements of the ASME Code.

The Class 1 piping used for the reactor vessel head vent is 1-inch schedule 160. In accordance with ASME Section III it is analyzed following the procedures of NC-3600 for Class 2 piping.
The piping stresses meet the requirements of ASME Code, Section III, NC-3600, with a design temperature of 650°F and a design pressure of 2485 psig.

The automatic depressurization system functions as a part of the passive core cooling system. The first stage automatic depressurization system valves are connected to the pressurizer. The valves are designed, constructed, and inspected to ASME Code Class 1 and seismic Category I requirements. Subsection 5.4.6 and Section 6.3 discuss the design bases for the automatic depressurization system and automatic depressurization system valves.

The primary function of the passive residual heat removal heat exchanger and core makeup tank high point vents is to prevent accumulation of noncondensable gases from the reactor coolant system that could interfere with operation of the passive core cooling system. Section 6.3 discusses the design bases for the passive residual heat removal heat exchanger, the core makeup tanks, and their vent lines.

5.4.12.2 System Description

The reactor vessel head vent arrangement consists of two flow paths, each with redundant isolation valves. Orifices are located downstream of each set of head vent isolation valves to limit the reactor vessel head vent flow rate. Table 5.4-18 lists the equipment design parameters. The reactor vessel head vent arrangement is shown on the reactor coolant system piping and instrumentation diagram (Figure 5.1-5).

The head vent arrangement consists of two parallel paths of two 1-inch, open/close, solenoid-operated isolation valves connected to a 1-inch vent pipe located near the center of the reactor vessel head. The

system design with two valves in series in each flow path minimizes the possibility of reactor coolant pressure boundary leakage. The solenoid-operated isolation valves are powered by the safety-related Class 1E DC and UPS system. The solenoid-operated isolation valves are fail-closed, normally closed valves. The valves are included in the valve operability program and are qualified to IEEE-323, IEEE-344, and IEEE-382.

The vent system piping is supported such that the resulting loads and stresses on the piping and on the vent connection to the vessel head are acceptable.

The automatic depressurization system valves are included as part of the pressurizer safety and relief valve module attached to the top of the pressurizer and are connected to the pressurizer nozzles. The automatic depressurization system includes a group of valves attached to the reactor coolant system hot leg that are not used to vent noncondensable gases. The pressurizer safety and relief valve module is supported by an attachment to the top of the pressurizer and provides support for the automatic depressurization system valves. The automatic depressurization system valves are active valves required to provide safe shutdown or to mitigate the consequences of postulated accidents. Subsection 5.4.6 discusses the function control and power requirements for the automatic depressurization system valves.

5.4.12.3 Safety Evaluation

The reactor vessel head vent system is designed so that a single failure of the remotely operated vent valves, power supply, or control system does not prevent isolation of the vent path. The two isolation valves in the active flow path provide a redundant method of isolating the venting system. With two valves in series, the failure of any one valve does not inadvertently open a vent path or prevent isolation of a flow path. **The DCD Chapter 15 accident analysis and supporting analyses are performed consistent with the reactor vessel head vent system design parameters provided in Table 5.4-18.**

The reactor vessel head vent system has two normally de-energized valves in series in each flow path. This arrangement eliminates the possibility of opening a flow path due to the spurious movement of one valve.

A break of the reactor vessel head vent system line would result in a small loss of coolant accident of not greater than one-inch diameter. Such a break is similar to those analyzed in subsection 15.6.5. Since a break in the head vent line would behave similarly to the hot leg break case presented in subsection 15.6.5, the results presented therein apply to a reactor vessel head vent system line break. This postulated vent line results in no calculated core uncovery.

Subsection 5.4.6 and Section 6.3 discuss the evaluation of the automatic depressurization system valves. Inadvertent opening of an automatic depressurization system valve is included in the transients considered for specification of the inadvertent reactor coolant system depressurization in subsection 3.9.1.

Section 6.3 discusses the evaluation of the passive residual heat removal heat exchanger and core makeup tanks. These high point vent lines contain two manual isolation valves in series, so that a single failure of either valve to reclose following venting operation does not prevent isolation of the flow path. The high point vent line from the passive residual heat removal heat exchanger to the in-containment refueling water storage tank contains a flow-restricting orifice such that postulated break flow is within the makeup capability of the chemical and volume control system and therefore would not normally require actuation of the passive safety systems.

Table 5.4-18

REACTOR VESSEL HEAD VENT SYSTEM DESIGN PARAMETERS

System design pressure, psig	2485
System design temperature, °F	650
Number of remotely-operated valves	4
Vent line, nominal diameter, inches	1
Head vent capacity, lbm/sec (assuming a single failure, RCS pressure at 1250 psia)	**8.2**

PRA Revision:

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 440.049 (Response Revision 1)

Question:

Section 5.4.12 of NUREG-0800, "Standard Review Plan [SRP] for the Review of Safety Analysis Reports for Nuclear Power Plants," specifies that procedures should be developed for use of the vent paths to remove gases that may inhibit core cooling from the U-tubes of the steam generators; and that the procedures to operate the vent system should consider when venting is needed, and when it is not needed, with consideration of a variety of initial conditions, operator actions, and necessary instrumentation.

Describe the AP1000 procedures for venting the RCS system, including the criteria for opening and closing the RVHVS valves and automatic depressurization system (ADS) first stage valves, respectively, the bases for these criteria, the necessary instrumentation, and the procedures.

Westinghouse Response:

The AP1000 reactor vessel head vent provides the plant with a safety-related, single-failure tolerant vent path that could be used to prevent pressurizer overfill following some accident scenarios. The design bases for the head vent include the ability to relieve water from the RCS at a flowrate sufficient to prevent pressurizer overfill during an event where the mass addition from the core makeup tanks (CMTs) causes an increase in pressurizer inventory that otherwise might overfill the pressurizer. In addition, the head vent retains the capability to vent non-condensable gasses that may accumulate in the RCS due to a severe accident.

The reactor vessel head vent valves are opened during plant startup operations to vent air from the reactor vessel head. Once the reactor vessel head is in place and bolted, the reactor coolant system is filled water solid, with the high point vents (including the reactor vessel head vents and the manual pressurizer high point vents) opened to allow air to be vented from the system. After the vents are closed, a reactor coolant pump in each steam generator is started and allowed to run for a short time, and is then stopped. The high point vent lines are then reopened to allow any air that collects in the high points to be vented. The vents are then reclosed, and the venting procedure is repeated until all of the air is removed from the RCS.

In addition to the normal venting procedures during plant startup, the AP1000 reactor vessel head vent could also be used under a design basis accident scenario. Following long-term (> 30 minutes) operation of the CMTs in response to a transient (non-LOCA) event, the pressurizer water level can increase and conservative Chapter 15 accident analyses indicate the pressurizer may eventually become water solid. To avoid this occurrence, the operator opens the head vent valves, based on indication of high pressurizer level, and reduces the inventory in the RCS, and prevents pressurizer overfill. When pressurizer level is sufficiently

reduced, the operator recloses the head vent valves. In this case the operator uses pressurizer level as the primary indication to control operation of the reactor vessel head vent.

Other reactor vessel head vent operations are a result of multiple failures in the passive safety-related systems including multiple ADS failures or possibly multiple failures in the passive RHR system. In these cases, manual operation is based on the operator recognizing the multiple failures in the passive safety-related systems, or based on high pressurizer level (in the case of multiple PRHR failures) as described above. In these cases, operation of the reactor vessel head vent prevents a buildup of non-condensable gasses in the RCS. The venting of non-condensable gasses is not a safety-related function required for mitigating design basis events.

Manual operation of the first stage ADS valves is not required to mitigate design basis accidents. Manual operation of the first stage ADS valves is performed in the case of multiple failures of safety-related systems, or is performed as a recovery action from a design basis event. Examples include manual operation of the first stage ADS in response to a steam generator tube rupture event if other means of RCS depressurization have failed, or manual operation to reduce the pressure in the RCS following a transient to allow initiation of the nonsafety-related normal RHR system. Manual operation of the ADS valves is also performed on indication of high core exit temperature indicative of a core damage event, or in the case of failure of the ADS valves to operate when required. Venting of the ADS valves under these circumstances helps mitigate these events by depressurizing the RCS and preventing the buildup of non-condensable gasses.

Design Control Document (DCD) Revision:

None

PRA Revision:

None

NRC Additional Comments:

In RCS ITAAC Table 2.1.2-4, the Acceptance Criterion for Design Commitment Item 8.e, (i.e., the RCS provides emergency letdown via the reactor vessel head vent system during design basis events to prevent long term pressurizer overfill) is that the capacity of the reactor vessel head vent is sufficient to pass not less than 8.2 lbm/sec at 1250 psia in the RCS. This acceptance criterion is the same as AP600.

Explain how this criterion is derived. Is it calculated from the RVHVS's venting capacity design basis of vent 40% of the RCS volume in one hour?

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

The response to 440.049 states that the design bases for the head vent include the ability to relieve water from the RCS at a flow sufficient to prevent pressurizer overfill during an event where the mass addition from the core makeup tanks (CMTs) causes an increase in pressurizer inventory that otherwise might overfill the pressurizer.

What is the limiting transient for pressurizer overfill? What is the rate of insurge into the pressurizer? Is ITAAC acceptance criterion of 8.2 lbm/sec corresponding to this insurge rate?

Westinghouse Revised Response:

See answer to RAI 440.048 Rev. 1

Design Control Document (DCD) Revision:

See answer to RAI 440.048 Rev. 1

PRA Revision:

None

RAI Number: 440.052 (Response Revision 1)

Question:

Section 7.3.1.2.4 describes the actuation logic and "preset time delays" of various stages of the ADS. For example, it states the preset time delay after the core makeup tank Low-1 level setpoint (coincident with the CMT injection signal) for actuation of ADS, stage 1 (ADS-1), subsequent time delays for actuations of ADS, stage 2 (ADS-2) and ADS, stage 3 (ADS-3), and the preset time delay after the CMT Low-2 level setpoint (coincident with low RCS pressure). It also states the preset time delay between the actuation of the isolation valves and the depressurization valves for various stages for the ADS. Table 15.6.5-7 specifies the earliest actuation times (or delay times) for the actuations of various stages of ADS.

Where are the delay times between the actuation of the isolation valves and the depressurization valves for various stages of ADS specified? What are the values assumed in the Chapter 15 design-basis analyses? Do the earliest actuation times for various stages listed on Table 15.6.5-7 include the delay times between the actuation of the isolation and control valves?

Westinghouse Response:

The time delays provided to allow for the opening of ADS isolation valves are included in the time delays shown in Table 15.6.5-7. For example, the ADS stage isolation valves have an maximum opening time of 20 sec. They are actuated on a ADS stage 1 actuation signal without any delay. As a result they will open during the 20 sec time delay shown in Table 15.6.5-7 "20 sec after CMT Low-1". The ADS stage 2 isolation valves have a maximum opening time of 30 sec. They are actuated 40 sec after a stage 1 signal, so that they will be open by the time the ADS stage 2 ADS valves start to open 70 sec after a ADS stage 1 signal. The ADS isolation valves for stage 3 and 4 are sequenced open in the same manner.

The Chapter 15 analysis assumes that the ADS isolation valves are sequenced open during the time delays shown in table 15.6.5-7. As a result, no other inputs to the safety analysis are necessary.

Table 15.6.5-7 shows all of the time delays for the ADS control valves.

Design Control Document (DCD) Revision:

None

PRA Revision:

None

NRC Additional Comment:

Table 15.6.5-7, "AP1000 ADS Parameters," is not clear regarding the values of various valve opening delay times (preset time delay and valve opening time), and the actual delay times used in Chapter 15 analysis.

What does Column 5 "valve opening time" mean? For example, stage 1 valve has opening time of 30 seconds? Does it mean it takes 30 seconds for the ADS-1 control (or depressurization) valve to be fully open? Is it the sum of the preset time delay after the opening of the isolation valve (see Section 7.3.1.2.4) plus the depressurization valve opening time? What are the values of the preset time delay and valve opening time? Also, does it mean that it takes 50 seconds (20 + 30) for the ADS-1 to be fully open?

Column 1, "Actuation Signal (Percentage of CMT level)," is not clear because of alignment. For example, for "Stage 1 - Control Low 1 67.5," does it mean the first stage valves are opened 20 seconds after CMT level reaches Low 1 (67.5%)? Also, Stage 4A does not have "control Low 2." Table 15.6.5-7 should be revised for clarity.

Westinghouse Additional Response:

DCD Table 15.6.5-7 (and 15.6.5-8) were inadvertently deleted in DCD Revision 3, and these tables will be added back in the next revision as Tables 15.6.5-8a and 15.6.5-8b as shown in the attachment. Furthermore, Table 15.6.5-8a has been clarified to address the comments.

The valve opening time listed in the Table is the maximum time it takes for the valve to stroke fully open. The actuation time column is describing the pre-set time delay. For example, it takes 50 seconds for ADS-1 to be fully open once the CMT level reaches the 1st stage actuation signal.

Table 15.6.5-8a

AP1000 ADS PARAMETERS

Actuation Signal (percentage of core makeup tank level)		Actuation Time (seconds)	Minimum Valve Flow Area (for each path, in^2)	Number of Paths	Valve Opening Time (seconds)
Stage 1 – Control Low 1	67.5	20 after CMT-Low 1	4.6	2 out of 2	≤ 30
Stage 2 – Control		70 after Stage 1	21	2 out of 2	≤ 80
Stage 3 – Control		120 after Stage 2	21	2 out of 2	≤ 80
Stage 4A	20	120 after Stage 3	67	1 out of 2	≤ 2
Stage 4B		60 after Stage 4A	67	2 out of 2	≤ 2

Table 15.6.5-8b

INADVERTENT ADS DEPRESSURIZATION SEQUENCE OF EVENTS

Event	AP1000 Time (seconds)
Inadvertent opening of the ADS valves	0.0
Reactor trip signal	37.8
Steam turbine stop valves close	43.8
"S" signal	44.1
Main feed isolation valves begin to close	49.1
Reactor coolant pumps start to coast down	50.1
ADS Stage 2	70.0
ADS Stage 3	190.0
Accumulator injection starts	268
Accumulator empties	693
ADS Stage 4	1746
Core makeup tank empty	2112
IRWST injection starts	2663

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 440.076 (Response Revision 1)

Question:

The feedwater line break (FLB) event is analyzed for a double-ended rupture of the largest feedwater line, which was previously identified in WCAP-9230,"Report on the Consequences of a Postulated Main Feedline Rupture," as the limiting case, resulting in a highest peak RCS pressure. Considering the plant design differences in the AP1000 and currently operating PWRs, the results of FLB analysis may be different and the limiting FLB case may be different from the one previously identified for currently operating PWRs.

Address the applicability of WCAP-9230 to the AP1000 design for determination of the limiting FLB case, and confirm that the double-ended rupture is the limiting break for AP1000.

Westinghouse Original Response:

WCAP-9230 was developed to assess the consequences of a feedline break accident for Westinghouse plants, in agreement with the criteria set forth in the Standard Review Plan, section 15.2.8. WCAP-9230 reports the results of a sensitivity study which determines those system parameters that have the most effects on the results of a system transient following a feedline break accident and defines the worst case initial conditions and assumptions, with and without offsite power available.

To address adverse environmental effects (control system interaction) applied to feedline rupture analyses, a subsequent methodology was needed. Specifically, it was postulated that the adverse steam-filled environment caused by the feedline rupture could have detrimental effects on the response of the feedwater control system.

For this particular accident scenario, the main feedwater control system equipment is assumed to be exposed to an adverse environment, following a feedwater line rupture between the steam generator and the feedline check valve. As a result of this adverse environment, the main feedwater control system malfunctions such that prior to reactor trip, the main feedwater flow in the faulted loop is equivalent to the fluid spilling out the break and no feedwater is being injected into the non-faulted steam generators. This results in no net feedwater flow out the faulted SG. The steam generator water levels will decrease as steam continues to be supplied to the turbine until a reactor trip on the low-low water level setpoint occurs. After reactor trip, the main feedwater control system is assumed to be lost and a full double-ended rupture blowdown is modeled in the faulted loop.

Assuming no blowdown prior to reactor trip is conservative because the assumption of a double-ended break at the initial time would result in an almost immediate reactor trip followed by the safety systems actuation (including steam lines and feed lines isolation). In this case, the intact steam generator inventory would be almost completely preserved and would provide a significant heat sink in the post trip part of the transient and, in particular, in the initial portion of the accident, during which PRHR heat transfer capacity is lower than core decay heat.

Smaller breaks can result in longer time to reactor trip and to safeguard actuations and hence less secondary side inventory would be available at the time of reactor trip and feed line isolation. Of course, in this case the blowdown phase would be slower than for a full double-ended rupture and, more time would be available for the safeguard systems to operate (lower system performances would be required in the short term). The resulting transient would be less limiting than the double ended guillotine rupture of the larger feedline. This is confirmed by the results of sensitivity studies reported in WCAP-9230 and by preliminary runs performed to analyze the behavior of the AP1000 plant.

Thus, the AP1000 feedline break accident is analyzed with the following conservative assumptions:

1) The accident is initiated by a break whose size is such that all the feedwater is spilled out of the break and no secondary fluid is discharged or supplied to the steam generators due to the feedwater control interaction.

2) In the first part of the accident, the plant behavior is the same as a loss of normal feedwater. The secondary system inventory, in both the steam generators, decreases at the same rate and due to the loss of subcooling in the steam generator, a moderate RCS heatup occurs.

3) At the time at which the Low-Low SG Water Level (Narrow Range) is reached (in both the steam generators at the same time), a trip signal is generated and a full double ended rupture of the main feed line is modeled.

4) The blowdown flow rate is evaluated as a critical discharge rate (L/D=0) for the cross sectional area of the main feedline. The fast blowdown results in a very fast drop of the secondary side inventory and complete loss of heat sink in the ruptured steam generator. During the blowdown from the ruptured steam generator, steam is also supplied from the intact steam generator to the ruptured one, until the steam lines are isolated following a low steam line pressure "S" signal. This also results in a decrease of the intact steam generator inventory.

5) A conservative blowdown quality is assumed in the analysis, as described in WCAP-9230 and further discussed in the answer to RAI 440.078.

Based on this, it can be concluded that the analysis methodology followed for the AP1000 and AP600 plant, covers the whole spectrum of feed line breaks. In fact, the first part of the transient is analyzed as loss of normal feedwater event. This results in a heatup of the RCS in the initial portion of the transient. In addition, in the post trip phase of the transient, a full double ended break of the main feed water is assumed. The plant conditions, at which the break occurs, are the worst possible ones in terms of steam generator residual mass, since both the steam generators are at the low-low steam generator water level and the minimum secondary inventory is available, in the intact steam generator, to provide, in conjunction with the PRHR operation, the required heat sink to remove the core decay heat.

Adoption of this analysis approach for both the AP600 and AP1000 conservatively addresses the main feedwater control system environmental interaction issue, the small and intermediate break sizes, and the operation of the feedwater control system following a small feedline rupture.

NRC Additional Comments:

The last two sentences in the second paragraph of page 440.76-2 state that '[t]he resulting transient (a small break) would be less limiting than the double ended guillotine rupture of the larger feedline. This is confirmed by the results of sensitivity studies reported in WCAP-9230 and by preliminary runs performed to analyze the behavior of the AP1000 plant."

Please summarize the results of the "preliminary runs" for the AP1000 design and address the adequacy of the quality of those "preliminary runs " used for supporting the AP1000 design certification application.

Westinghouse Additional Response:

The sensitivity runs referred to in the original Response were performed at the beginning of the AP1000 design process and were based on preliminary design information. The break used for comparison was about 50% of the full nozzle area. The results indicated that the full double ended break was the limiting transient since, despite the same pressurizer pressure peak and pressurizer water level, the subcooling margin was somewhat reduced. No additional evaluations were made since the results fully confirmed our expectations.

In order to answer the NRC Additional Comments, new sensitivity studies have been performed to demonstrate that, on the basis of the Westinghouse conservative method of analysis, large feedline break (FLB) are the limiting transients to be analyzed.

The sensitivity study compares the results of the limiting transient, presented in the DCD and analyzed according to the methodology described in the previous answer to the RAI, with FLB analyses for break sizes of 100%, 50%, 25% and 10% of the feedwater nozzle area, performed assuming the break occurring at the initial transient time.

Figures 1 through 3 compare the Reactor Coolant System Pressure behavior for the full double ended break case with smaller break cases, assuming the break occurring at the initial transient time. Figures 4 through 6 compare the PRZ Water Volume behavior for the full double ended break case with smaller break cases, assuming the break occurring at the initial transient time.

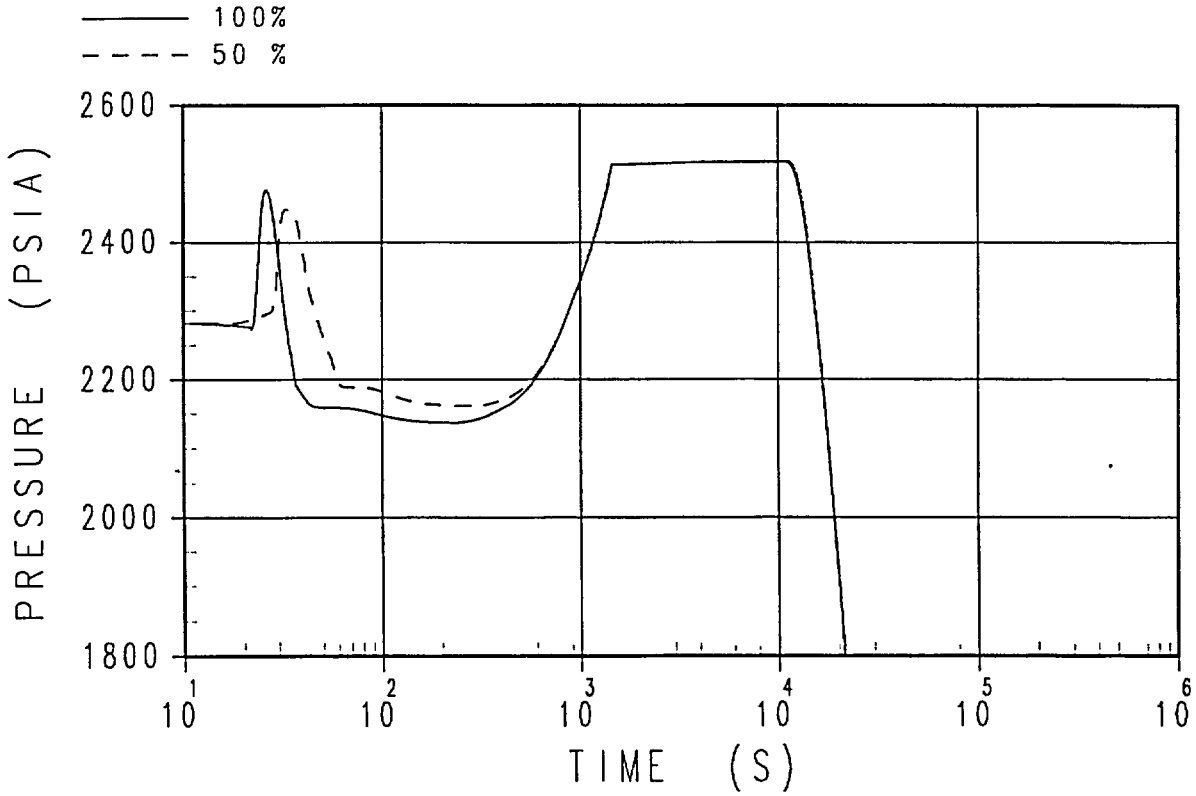

Figure 1 – RC Pressure versus Time
Comparison of a Full double Ended Feed Line Rupture With
a Break Corresponding to 50% of the FW Nozzle Flow Area

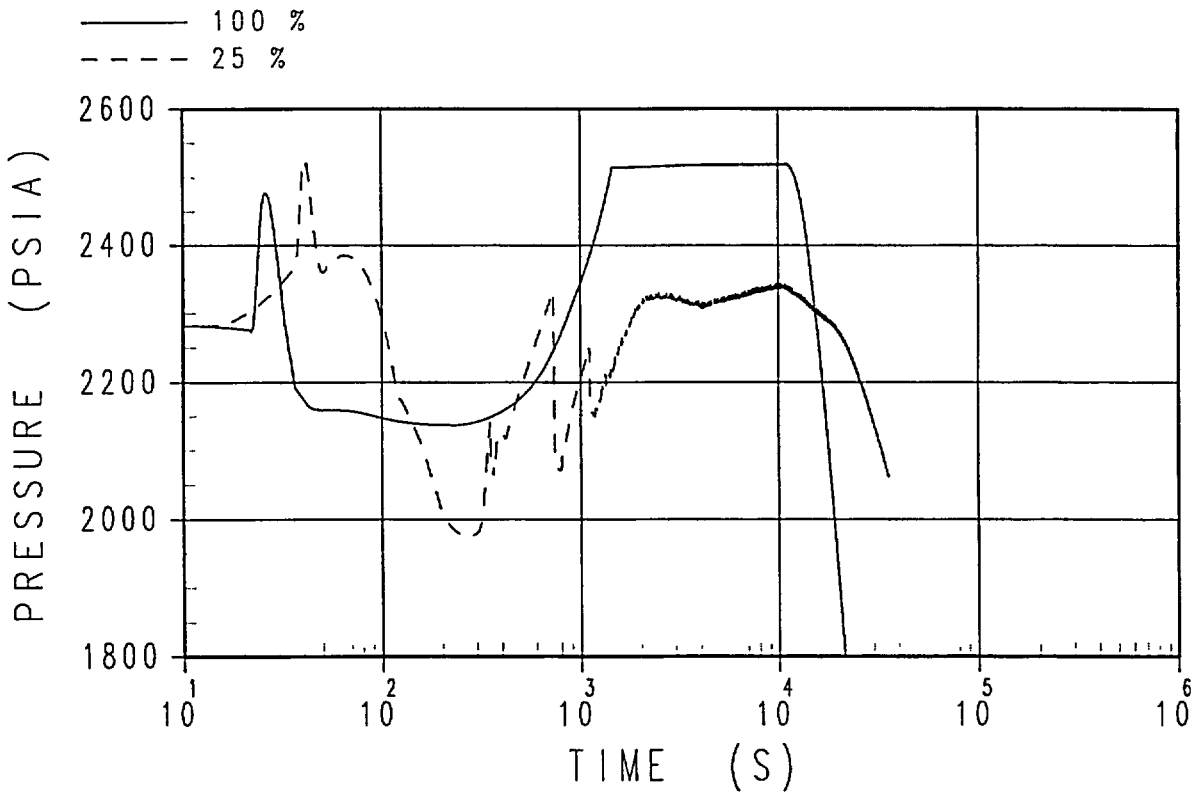

Figure 2 – RC Pressure versus Time
Comparison of a Full double Ended Feed Line Rupture With
a Break Corresponding to 25% of the FW Nozzle Flow Area

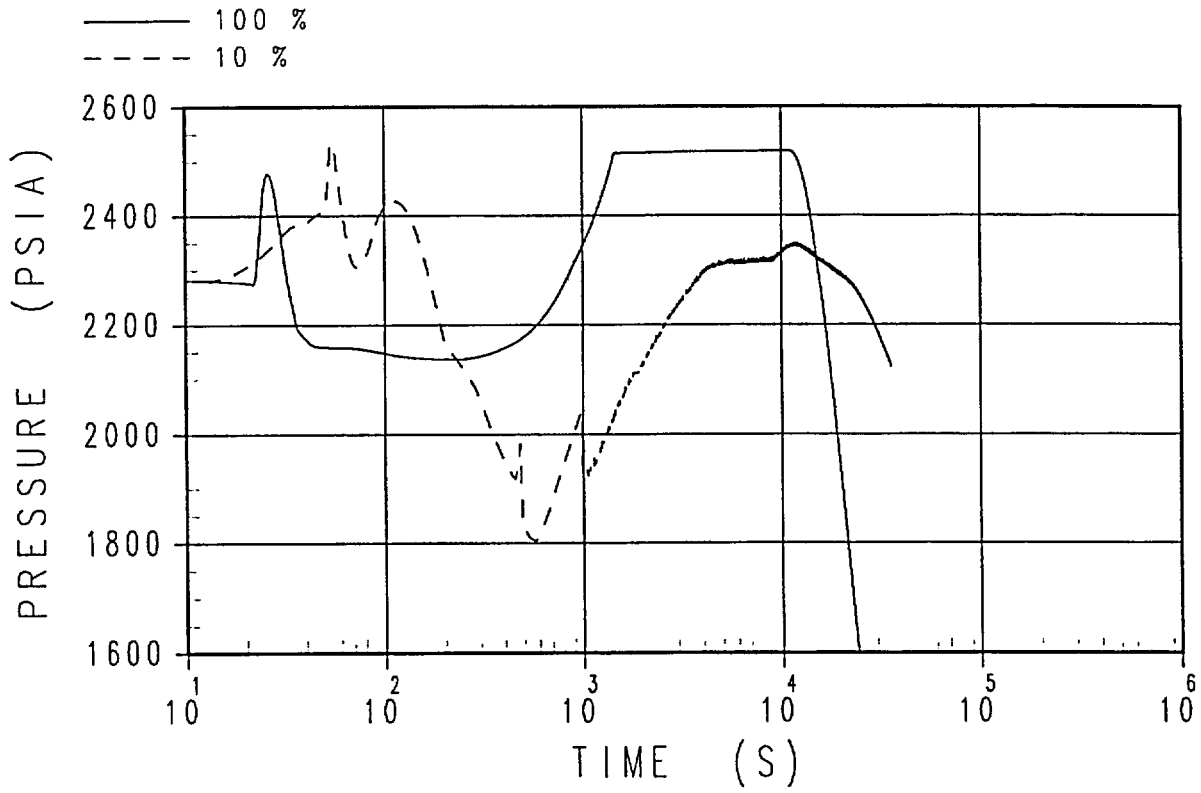

Figure 3 – RC Pressure versus Time
Comparison of a Full double Ended Feed Line Rupture With
a Break Corresponding to 10% of the FW Nozzle Flow Area

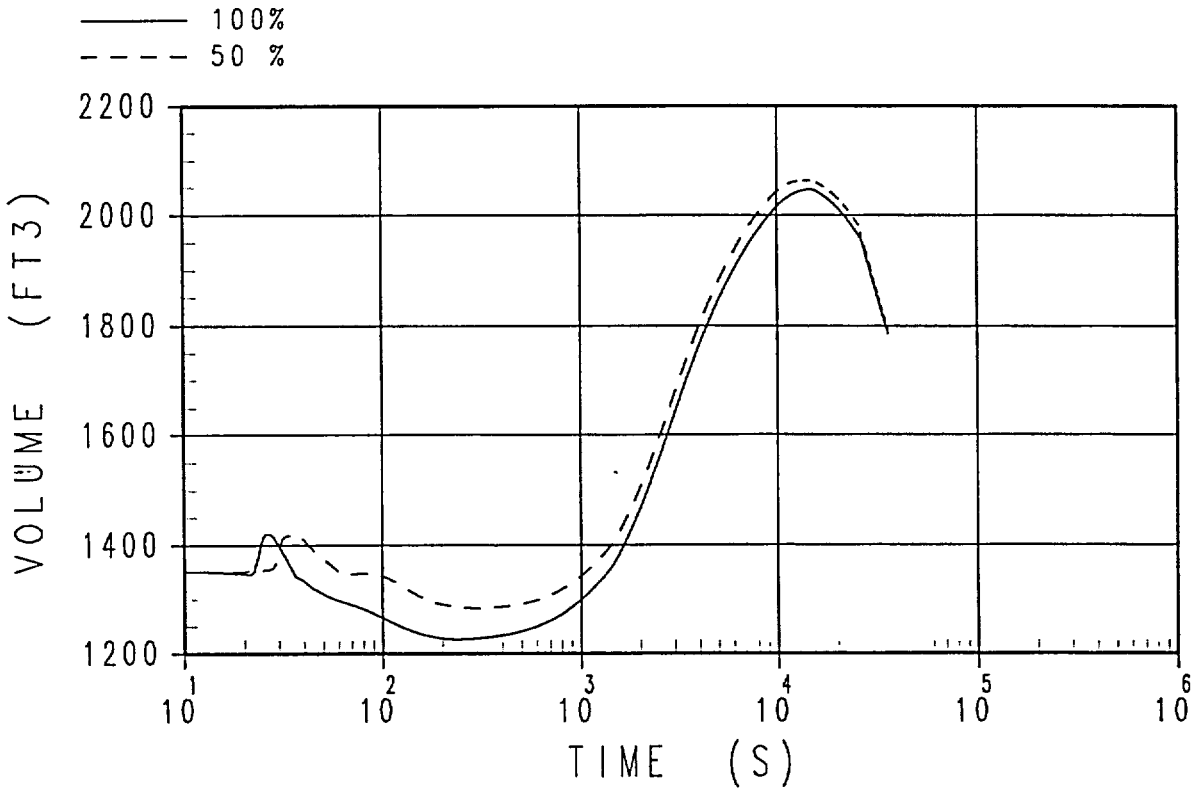

Figure 4 – PRZ Water Volume versus Time
Comparison of a Full double Ended Feed Line Rupture With
a Break Corresponding to 50% of the FW Nozzle Flow Area

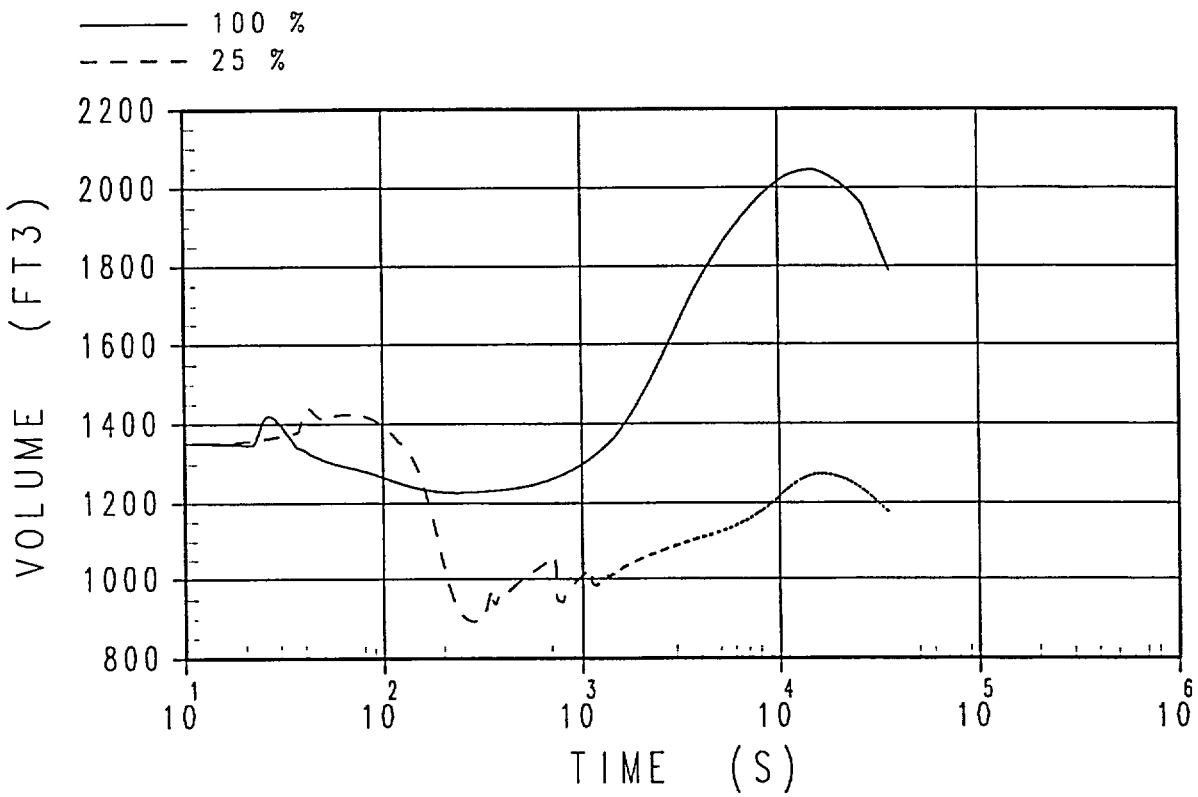

Figure 5 – PRZ Water Volume versus Time
Comparison of a Full double Ended Feed Line Rupture With
a Break Corresponding to 25% of the FW Nozzle Flow Area

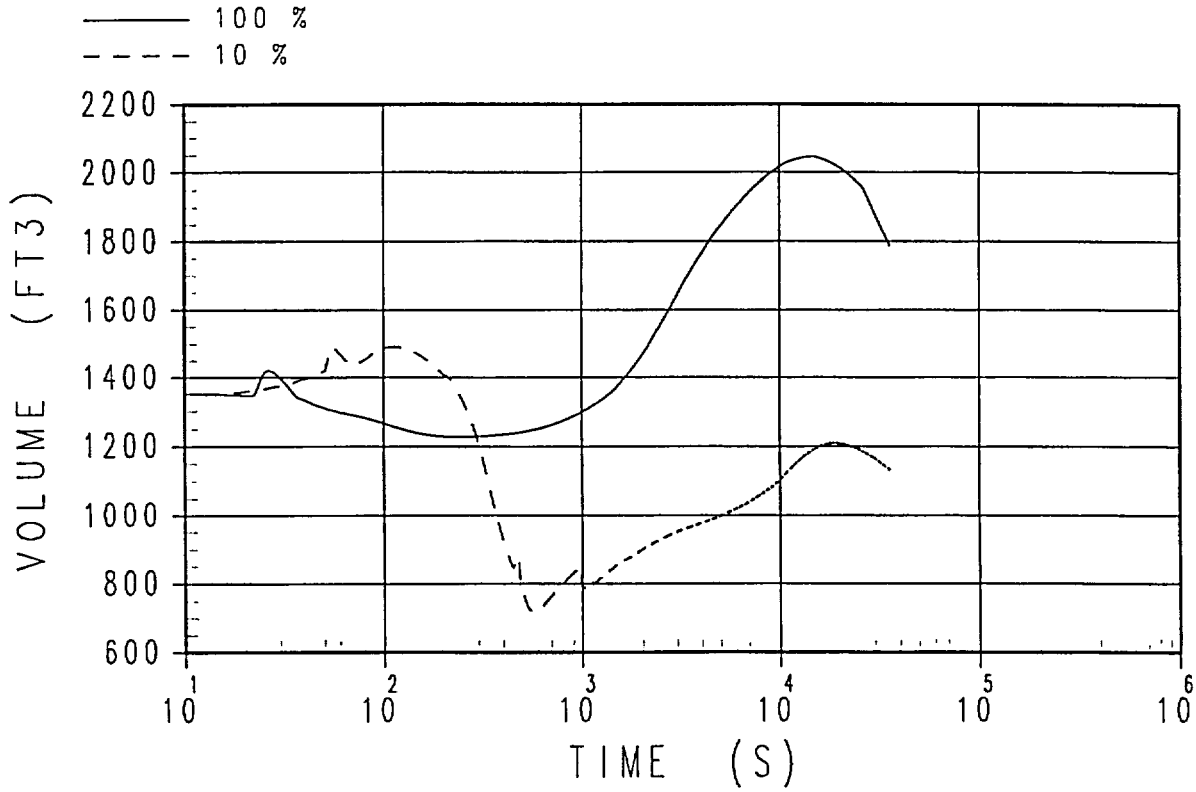

Figure 6 – PRZ Water Volume versus Time
Comparison of a Full double Ended Feed Line Rupture With
a Break Corresponding to 10% of the FW Nozzle Flow Area

The figures above show that, in the short term, small break cases provide worst results with respect to the larger ones (higher RCS heat-up, PRZ pressure and Pressurizer water volume), whilst larger breaks provide worst results in the long term (a larger secondary side inventory is available in the post trip phase to extract RCS heat). The 50% break case is very similar to the 100% since, for both the cases, the blow down is very fast.

Figures 7 and 8 compare the results of the cases above with the most limiting case reported in the DCD.

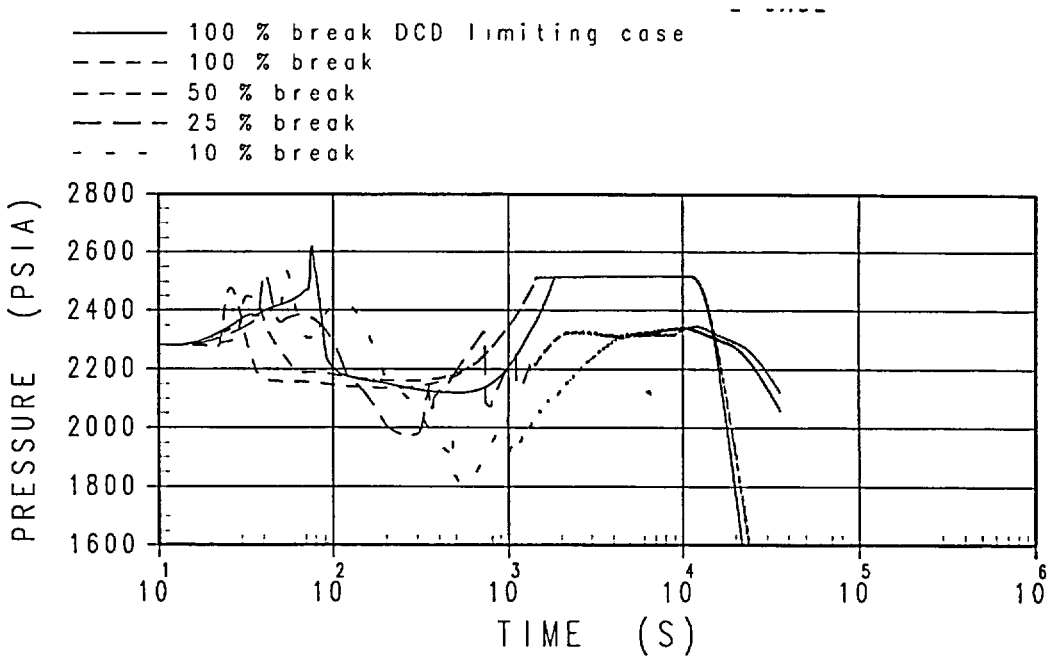

Figure 7 – RC System Pressure versus Time
Comparison of a DCD Full double Ended Feed Line Rupture Case With
Break Spectrum from 100% to 10% of the FW Nozzle Flow Area

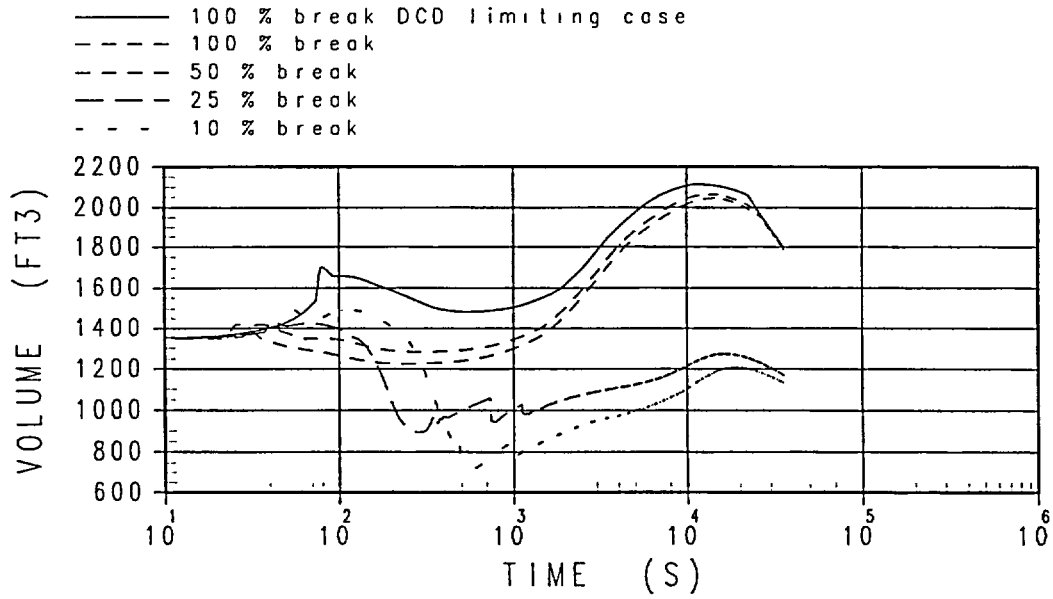

Figure 8 – PRZ Water Volume versus Time
Comparison of a DCD Full double Ended Feed Line Rupture Case With
Break Spectrum from 100% to 10% of the FW Nozzle Flow Area

These figures show that the analysis presented in the DCD bounds the results of the whole spectrum of FLB sizes, both in the short and in the long term.

The analysis methodology adopted for the FLBA and described in the previous answer to the RAI is characterized by a first part of the analysis (before the reactor trip) in which no water is added or lost through the steam generators (similar to a loss of normal feedwater (LNFW) event). The steam generator water level slowly decreases and reactor trip occurs on a Low SG Water Level. The resulting heat up of the primary system bounds the transients caused by any small break.

In the second part of the transient (after the turbine trip) a full double ended break develops that immediately depletes the affected steam generator. This, combined with conservative assumptions related to the break quality, immediately cut down the affected steam generator heat transfer capability and results in a more severe transient in the long term.

Table 1 reports the time sequence of events for the cases analyzed.

Design Control Document (DCD) Revision:

None

PRA Revision:

None

Table 1
FLB Sensitivity Study on Break Size

Event	Time (seconds)				
Break Size (% of the FW Nozzle Area)	**DCD Case**	**100**	**50**	**25**	**10**
Transient started, feed water lost	10	10	10	10	10
Reverse flow from SG starts	70.3	10	10	10	10
Low narrow SG level set point reached	70.3	18.9	25.4	34.5	47.8
Rod insertion begins	72.3	20.9	27.4	36.5	49.8
RCP starts to coastdown	72.3	20.9	27.4	36.5	49.8
Pressurizer safety valves open	74.5	-	-	-	-
Maximum RCS pressure reached first peak	76 (2621 psia)	26 (2475 psia)	33 (2450 psia)	41 (2526 psia)	54.5 (2534 psia)
Maximum PRZ volume reached (first peak)	80 (1704 ft^3)	26.5 (1420 ft^3)	36 (1420 ft^3)	41.5 (1440 ft^3)	113 (1493 ft^3)
Pressurizer safety valves close	80	-	-	-	-
Low wide SG level set point reached	73	21.8	30.8	44.5	69.1
S signal is reached (1)	78	29.7	49.3	124.9	260
Steam lines are isolated on S signal	90	41.7	61.3	136.9	272
PRHR actuated on low WR level	90	38.8	47.8	61.5	86.1
CMT is actuated on S signal	95	46.7	66.3	141.9	277
SG (intact loop) safety valves open	180	-	-	-	61
SG safety valves close	425	-	-	-	86.5
PRZ safety valves reopen	1848	1450	1462	-	-
Maximum RCS pressure reached second peak	1850 (2519 psia)	7268 (2519 psia)	6730 (2519 psia)	10,500 (2336 psia)	12,000 (2343 psia)
Maximum PRZ volume reached second peak	11,340 (2114 ft^3)	14,036 (2046 ft^3)	13,544 (2063 ft^3)	16,500 (1273 ft^3)	19,000 (1210 ft^3)
PRHR matches decay heat	11,400	12,000	11,800	14,880	17,800
PRZ safety valves reclose	11,376	11456	11,480	-	-

(1) S signal:
- * low SL pressure for cases DCD, 100, 50
- ** low Tcold for cases 25 & 10

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 440.089 (Response Revision 1)

Question:

Page 15.6-11 of Chapter 15 indicates that in the SGTR analysis, the ruptured SG power-operated relief valve (PORV) is assumed to fail open when the low-2 pressurizer level "S" signal generates, while page 15.6-12 and Table 15.6.3-1 show that the failure of the PORV occurs on the low pressurizer pressure "S" signal.

Provide the rationale for selection of the time of the SG PORV to fail and show that the selected PORV failure time results in a maximum RCS mass release and is conservative for the SGTR analysis. Correct any inconsistencies in Chapter 15 for the PORV failure time.

Westinghouse Response:

The most probable time for the PORV to fail open would be at reactor trip, when the valve initially opens to relieve steam due to the loss of steam dump to condenser associated with the assumed loss of offsite power. In analyses for operating plants performed with the approved methodology of Supplement 1 to WCAP-10698, the failure is conservatively delayed until the time when the operators is assumed to isolate the ruptured steam generator. Delaying the failure allows for accumulation of activity in the secondary system (and in the primary system in the case with the accident initiated iodine spike). The delayed failure also results in higher integrated releases by delaying the actions that lead to break flow and steam release termination. For the AP1000 the analysis does not credit operator actions, so a different time was selected. The assumption of a delayed failure was retained resulting in the buildup of activity and higher integrated releases seen in operating plant analyses. Once an "S" signal is generated the passive safety systems act to reduce the atmospheric releases by reducing heat transfer to the steam generators, and reducing RCS pressure. Since the PORV failure itself would result in an "S" signal being generated (on low steamline pressure, or low pressurizer pressure or level) the failure was delayed such that the failure would not provide any benefits in actuating safety systems.

The inconsistencies in Chapter 15 for the PORV failure time will be corrected as shown.

Design Control Document (DCD) Revision:

DCD section 15.6.3.2.1.2 and Table 15.6.3-1 will be revised as follows:

The reactor is assumed to be operating at full power at the time of the accident, and the initial secondary mass is assumed to correspond to operation at nominal steam generator mass minus an allowance for uncertainties. Offsite power is assumed to be lost and the rods are assumed to be inserted at the start of the event because continued operation of the reactor coolant pumps has been determined to reduce flashing of primary-to-secondary break flow and, consequently, lower offsite radiological doses. Maximum chemical and volume control system flows and pressurizer heater heat addition are assumed immediately (even though offsite power is not available) to conservatively maximize primary-to-secondary leakage. The steam dump system is assumed to be inoperable, consistent with the loss of offsite power assumption, because this results in steam release from the steam generator power-operated relief valves to the atmosphere following reactor trip. The chemical and volume control system and pressurizer heater modeling is conservatively chosen to delay the low pressurizer pressure "S" **and the low-2 pressurizer level** signal and associated protection system actions.

The limiting single failure is assumed to be the failure of the ruptured steam generator power-operated relief valve. Failure of this valve in the open position causes an uncontrolled depressurization of the ruptured steam generator, which increases primary-to-secondary leakage and the mass release to the atmosphere.

It is assumed that the ruptured steam generator power-operated relief valve fails open when **either** the low-2 pressurizer level **signal or the low pressurizer** "S" signal **are** generated. This results in the maximum integrated flashed primary-to-secondary break flow.

Table 15.6.3-1

STEAM GENERATOR TUBE RUPTURE SEQUENCE OF EVENTS

Events	Time (seconds)
Double-ended steam generator tube rupture	0
Loss of offsite power	0
Reactor trip	0
Reactor coolant pumps and main feedwater pumps assumed to trip and begin to coastdown	0
One chemical and volume control pump actuated and pressurizer heaters turned on	0
Low-**2 pressurizer level signal** generated	2,498
Ruptured steam generator power-operated relief valve fails open	2,498
Core makeup tank injection and PRHR operation begins (following maximum delay)	2,515
Ruptured steam generator power-operated relief valve block valve closes on low steamline pressure signal	2,979
Chemical and volume control system isolated on high-2 steam generator narrow range level setpoint	12,541
Break flow terminated	24,100

PRA Revision:

None

NRC Additional Comments:

In the response to RAI 440-089, it stated that "... the PORV failure itself would result in an "S" signal being generated (on low steamline pressure, or low pressurizer pressure or level)..." This statement implies that the "S" signal can be actuated on a low pressurizer level signal . This is inconsistent with Item 1 of TS Table 3.3.2-1, which does not require the pressurizer low level signal to actuate a "S" signal.

Westinghouse Revised Response:

The response is modified above to clarify the discrepancy. The safeguards actuation "S" signal is not actuated on low pressurizer water level. The low pressurizer water level signal (low-2) results in actuation of the core makeup tanks.

The most probable time for the PORV to fail open would be at reactor trip, when the valve initially opens to relieve steam due to the loss of steam dump to condenser associated with the assumed loss of offsite power. In analyses for operating plants performed with the approved methodology of Supplement 1 to WCAP-10698, the failure is conservatively delayed until the time when the operators is assumed to isolate the ruptured steam generator. Delaying the failure allows for accumulation of activity in the secondary system (and in the primary system in the case with the accident initiated iodine spike). The delayed failure also results in higher integrated releases by delaying the actions that lead to break flow and steam release termination. For the AP1000 the analysis does not credit operator actions, so a different time was selected. The assumption of a delayed failure was retained resulting in the buildup of activity and higher integrated releases seen in operating plant analyses. Once an "S" signal is generated the passive safety systems act to reduce the atmospheric releases by reducing heat transfer to the steam generators, and reducing RCS pressure. Since the PORV failure itself would result in an "S" signal being generated (on low steamline pressure or low pressurizer pressure) or CMT actuation on low-2 pressurizer level the failure was delayed such that the failure would not provide any benefits in actuating safety systems.

Design Control Document (DCD) Revision:

DCD revision 3 section 15.6.3.2.1.2 will be revised to clarify the discrepancy as shown below:

15.6.3.2.1.2 Analysis Assumptions

The accident modeled is a double-ended break of one steam generator tube located at the top of the tube sheet on the outlet (cold leg) side of the steam generator. The location of the break on the cold leg side of the steam generator results in higher initial primary-to-secondary leakage than a break on the hot side of the steam generator.
The reactor is assumed to be operating at full power at the time of the accident, and the initial secondary mass is assumed to correspond to operation at nominal steam generator mass minus an allowance for uncertainties. Offsite power is assumed to be lost and the rods are assumed to be inserted at the start of the event because continued operation of the reactor coolant pumps has been determined to reduce flashing of primary-to-secondary break flow and, consequently, lower offsite radiological doses. Maximum chemical and volume control system flows and pressurizer heater heat addition are assumed immediately (even though offsite power is not available) to conservatively maximize primary-to-secondary leakage. The steam dump system is assumed to be inoperable, consistent with the loss of offsite power assumption, because this results in steam release from the steam generator power-operated relief valves to the atmosphere following reactor trip. The chemical and volume control system and pressurizer heater modeling is conservatively chosen to delay the low pressurizer pressure "S" and the low-2 pressurizer level signal and associated protection system actions.

The limiting single failure is assumed to be the failure of the ruptured steam generator power-operated relief valve. Failure of this valve in the open position causes an uncontrolled depressurization of the ruptured steam generator, which increases primary-to-secondary leakage and the mass release to the atmosphere.

It is assumed that the ruptured steam generator power-operated relief valve fails open when either the low-2 pressurizer level signal **is generated**. This results in the maximum integrated flashed primary-to-secondary break flow.

The valve is subsequently isolated when the associated block valve is automatically closed on a low steam line pressure protection system signal.

No operator actions are modeled in this limiting analysis, and the plant protection system provides the protection for the plant. Not modeling operator actions is conservative because the operators are expected to have sufficient time to recover from the accident and supplement the automatic protection system. In particular, the operator would take action to reduce the primary pressure before the high-2 steam generator level chemical and volume control system shutoff signal is generated. It is also expected that the operator can close the block valve to the ruptured steam generator power-operated relief valve in much shorter time than the automatic protection signal. The operators can quickly diagnose a power-operated relief valve failure based on the rapid depressurization of the steam generator and increase in steam flow. They can then close the block valve from the control panel.

Consistent with the assumed loss of offsite power, the main feedwater pumps coast down and no startup feedwater is assumed to conservatively minimize steam generator secondary inventory and thus maximize secondary activity concentration and steam release.

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 440.099 (Response Revision 1)

Question:

During the review of the Westinghouse AP600, the NRC staff raised the issue of boron dilution associated with the SBLOCA reflux condensation, the so called "Finnish Scenario." The staff requested Westinghouse to address the issue in a letter to Westinghouse entitled "AP600 Boron Dilution Transient Analyses, " dated September 2, 1996 (AP600 request for additional information (RAI) No. 440.120). The staff is again requesting Westinghouse to address the same issue as it applies to the AP1000. Westinghouse should also address subsequent concerns that were raised by the staff as a consequence of the incomplete response to the September 2, 1996, letter. The subsequent letters referred to here were dated May 14, 1997, "Revised Response to RAI 440.120 for Rapid Boron Dilution Scenarios"; October 1, 1997, "Response to Request for Additional Information on Mixing in Downcomer and Lower Plenum" (RAI 440.724); and January 16, 1998," AP600 Response to FSER [final safety evaluation report] Open Items."

NRC Additional Comments:

Regarding the response to question 440.099 (boron dilution due to a small break loss-of-coolant accident [SBLOCA]), the sentence in the middle of the sixth Paragraph states that "lower AP1000 core boron concentration significantly reduces the potential to dilute the coolant in the reactor vessel to the point of criticality." Please provide additional clarification to this statement and the overall paragraph.

Westinghouse Additional Response:

The response is trying to explain that the beginning of life (BOL) boron concentration for the AP1000 is less than that of the AP600. Therefore, at BOL, the AP1000 operating boron concentration is less (on an absolute basis) than the AP600 RCS boron concentration. Therefore, given that the boration sources (core makeup tanks, accumulators and IRWST) boron concentrations are the same for AP1000 and AP600, and given that the AP1000 control rods contain additional shutdown worth, the AP1000 negative reactivity insertion mechanisms (boron and rods) are more effective in mitigating a boron dilution in the AP1000, when compared to the AP600. Overall, both the AP600 and the AP1000 are not susceptible to an unacceptable post-LOCA boron dilution as postulated in the "Finnish Scenario." The response is revised to clarify this point.

Westinghouse Response: (Revision 1)

As was the case for the AP600, the Finnish Center scenario is not significant to the AP1000 reactor design because the steam generators are not relied on to cool the RCS during a LOCA event. Consequently, the steam generators should not generate any significant amount of boron-free condensate via reflux condensation over an extended period of time during a LOCA event. In the AP1000 design, the steam generator functions as a "heat source" as the RCS depressurizes, rather than a "heat sink" as it does in conventional PWR designs. Therefore, the differential temperature across the primary and secondary side of the generators is such that steam from the reactor will not condense on the tubes.

For the AP600 and AP1000, the PRHR heat exchanger becomes a dominant RCS heat sink following the generation of an "S" signal during postulated SBLOCA events. During the licensing review of the AP600, it was postulated that the PRHR heat exchanger could become a potential source for generating a volume of unborated coolant during a small break LOCA. The staff was concerned that such a scenario could be postulated, and that a reactivity excursion could occur as a result of a restart of a reactor coolant pump after an unborated water slug had collected in the reactor coolant loop. This additional scenario was also shown not to be a safety concern for the AP600.

This scenario is also not a concern for the AP1000 for the same reasons as was given for the AP600. Specifically, the AP1000 reactor coolant loop piping does not contain a loop seal, and thus there is not a collection point for a large slug of unborated condensate to collect in the reactor coolant loop piping. During the small break LOCA, once subcooling in the RCS is lost, steam will enter the PRHR heat exchanger, and will condense on the inside of the PRHR heat exchanger tubes. Steam condensed in the PRHR is delivered to the Loop 1 steam generator outlet plenum. However, like the AP600, the AP1000 loop layout does not contain an RCP crossover leg, and the PRHR condensate will drain continuously from the steam generator channel head into the Loop 1 cold legs, and flow into the reactor vessel. A deborated water slug cannot accumulate in the RCS loop cold legs. During the SBLOCA transient, the water in the cold legs enter the downcomer, where it mixes with the highly borated safety injection flow from either the accumulators, the core makeup tanks, or both. As was the case for the AP600, the relatively low flow rate of fluid from the downcomer into the core during the post RCP-trip natural circulation phase of the AP1000 SBLOCA events enables mixing to occur in the downcomer, and lower plenum. No unmixed slugs of unborated water from the PRHR can form in the downcomer and enter the core during this scenario.

Bounding calculations performed for the AP600, as reported in the Westinghouse response to NRC AP600 RAI 440.720 quantitatively demonstrated that it was not credible to postulate that the boron concentration in the downcomer and lower plenum would be diluted to a critical boron concentration for postulated LOCA. The conclusions from these studies that boron dilution from the operation of the PRHR heat exchanger would not occur was based on demonstration that

the PRHR condensate would adequately mix with the water in the downcomer and lower plenum, so that a critical boron concentration would not be reached.

These conclusions are also applicable to the AP1000, even when considering pertinent design differences between the AP600 and the AP1000. The AP1000 uses a lower boron core design. The BOL boron concentration for the AP1000 is approximately 1000 ppm, as compared to approximately 1400 ppm (BOL, equilibrium core cycle, equilibrium xenon) for the AP600. **Therefore, given that the boration sources (core makeup tanks, accumulators and IRWST) boron concentrations are the same for AP1000 and AP600, and given that the AP1000 control rods contain additional shutdown worth, the AP1000 negative reactivity insertion mechanisms (boron and rods) are more effective in mitigating a boron dilution.** Although the AP1000 PRHR flow rate is somewhat larger than for the AP600, the CMT flow rate is also larger, and the reactor vessel downcomer and lower plenum volume is also larger. Taking these differences into account, the AP1000 design changes do not invalidate the conclusions of the earlier AP600 studies, and that post-LOCA boron dilution is not a concern provided that there is good mixing in the vessel.

As was the case for the AP600, mixing in the reactor vessel downcomer and lower plenum are counteract boron dilution in the core due to PRHR operation. For the AP600, Westinghouse identified further technical information to justify that significant mixing occurs in the AP600 downcomer during postulated small break LOCA boron dilution scenarios. Specifically, the Reference 440.099-1 study of the mixing of high pressure safety injection (HPI) water with primary coolant in a simulated PWR downcomer was shown to be relevant to the possible AP600 scenarios. The reference 1 study is also applicable to the AP1000, as discussed below.

Test #106 in Reference 440.099-1 considers a geometry which is representative of the PRHR condensate delivery geometry into the AP1000 downcomer, namely equal flow rates of liquid entering the downcomer through two cold legs which are 90 degrees apart at the connection into the reactor vessel. The downcomer in the Reference 440.748F-1 Loviisa test facility is shorter in length (approximately 10 ft) than the AP1000 dimension (approximately 20 ft from the cold leg bottom to the bottom of the downcomer). The test facility therefore provides less than one-half of the mixing length available in the AP1000 downcomer. The fluid velocity in the test facility cold legs is approximately 0.45 ft/second for the simulated HPI flow injection in Test #106, as indicated by the "C" series of figures in Reference 440.099-1. This is similar to the velocity of the PRHR condensate in the cold legs for small-break LOCA scenarios. Therefore, the parameters of Test #106 are such that the observed results provide meaningful insights into the mixing that occurs in the AP1000 downcomer during the small break LOCA boron dilution scenarios. The results of Test #106 illustrate that the injected plume thoroughly mixes with the resident downcomer liquid during the 10 ft. fall to the bottom elevation.

Further support for AP1000 downcomer mixing is provided by the Test #I 13 results of Reference 440.099-1. Test #113 was run at a simulated HPI injection rate which is 3.6 times greater than that of Test #I06 with a 60 degree angle between the two cold leg injection connections, as depicted in the "D" series of photographs in Reference 440.748F-1. Test #113

results show mixing behavior in the downcomer which closely resembles that of Test #106. Test #113 indicates that the sensitivity of downcomer mixing to initial plume velocity is minor. These two tests from Reference 440.099-I provide compelling evidence that the dilute boron stream in the AP1000 PRHR condensate delivery scenarios is well mixed in the downcomer and that no unmixed slugs enter the lower plenum or core.

The Reference 440.099-1 test results provide additional independent technical justification that the degree of mixing which occurs in the AP1000 downcomer during the PRHR condensate return scenarios is adequate to disperse a plume of dilute boron liquid. The test results support the conclusion that recriticality of the core is not of concern for small break LOCA scenarios.

References:

440.099-1 NUREG/IA-0004, "Thermal Mixing Tests in a Semiannular Downcomer with Interacting Flows from Cold Legs," USNRC. October 1986.

Design Control Document (DCD) Revision:

None

PRA Revision:

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 451.008

Question:

The relative concentration (X/Q) value provided in the AP1000 DCD is listed for the site boundary. However, dose regulations are based upon the exclusion area boundary (EAB). Is Westinghouse assuming that the site boundary values also apply to the EAB? If so, this should be explicitly stated.

Westinghouse Response:

For the AP1000, the "exclusion area boundary" is the same as the "site boundary", and therefore the terms can be used interchangeably. Thus, the X/Q specified for the site boundary also applies to the exclusion area boundary.

Design Control Document (DCD) Revision:

DCD Table 2-1 is revised as shown.

PRA Revision:

None

Table 2-1 (Sheet 2 of 2)

SITE PARAMETERS

Missiles	
Tornado	4000 - lb automobile at 105 mph horizontal, 74 mph vertical 275 - lb, 8 in. shell at 105 mph horizontal, 74 mph vertical 1 inch diameter steel ball at 105 mph horizontal and vertical
Flood Level	Less than plant elevation 100′
Ground Water Level	Less than plant elevation 98′
Plant Grade Elevation	Less than plant elevation 100′ except for portion at a higher elevation adjacent to the annex building
Precipitation	
Rain	19.4 in./hr (6.3 in./5 min)
Snow/Ice	75 pounds per square foot on ground with exposure factor of 1.0 and importance factors of 1.2 (safety) and 1.0 (non-safety)
Atmospheric Dispersion Values - X/Q[e]	
Site boundary (0-2 hr)	$\leq 0.60 \times 10^{-3}$ sec/m^3
Site boundary (annual average)	$\leq 2.0 \times 10^{-5}$ sec/m^3
Low population zone boundary	
0 - 8 hr	$\leq 1.35 \times 10^{-4}$ sec/m^3
8 - 24 hr	$\leq 1.0 \times 10^{-4}$ sec/m^3
24 - 96 hr	$\leq 5.4 \times 10^{-5}$ sec/m^3
96 - 720 hr	$\leq 2.2 \times 10^{-5}$ sec/m^3
Population Distribution	
Exclusion area (site)	0.5 mi

Notes:

(a) Maximum and minimum safety values are based on historical data and exclude peaks of less than 2 hours duration.

(b) Maximum and minimum normal values are the 1 percent exceedance magnitudes.

(c) With ground response spectra (at plant grade) as given in Figures 3.7.1-1 and 3.7.1-2.

(d) The noncoincident wet bulb temperature is applicable to the cooling tower only.

(e) **For AP1000, the terms "site boundary" and "exclusion area boundary" are used interchangeably. Thus, the X/Q specified for the site boundary applies whenever a discussion refers to the exclusion area boundary.**

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 460.007

Question:

(Section 11.4) Staff guidance for the radioactive waste storage capacity that is sufficient to allow time for short-lived radionuclides to decay prior to shipping is discussed in SRP Section 11.4, Paragraphs II.6 and III.4, and BTP ETSB II-3, Position B.III. Please demonstrate that the AP1000 design has such sufficient storage capacity. Clarify which generation rate (expected or maximum) is used for this demonstration. Identify the in-plant storage space (spent resin tanks, spent filter tubes,...etc.) associated with different kind of wastes (wet wastes, dry wastes,...etc.), shipment capacity, and duration for in-plant storage.

Westinghouse Response:

BTP ETSB II-3 Position B.III has the following requirements:

III. WASTE STORAGE

1. *Tanks accumulating spent resins from reactor water purification systems should be capable of accommodating at least 60 days waste generation at normal generation rates. Tanks accumulating spent resins from other sources and tanks accumulating filter sludges should be capable of accommodating at least 30 days waste generation at normal generation rates.*
2. *Storage areas for solidified wastes should be capable of accommodating at least 30 days waste generation at normal generation rates. These storage areas should be located indoors.*
3. *Storage areas for dry wastes and packaged containment equipment should be capable of accommodating at least one full offsite waste shipment.*

As reported in Table 11.4-1 of the AP1000 DCD, the expected spent primary resin generation rate (using ANSI 18.1 source terms) is 400 cubic feet per year. This value is conservatively estimated, and includes the following:

	Vessel Volume ft^3	Change Freq., Months	Generation ft^3/yr
WLS Deep Bed Charcoal	10	3	40
WLS Deep Bed Resin	40	6	80
WLS 1 Resin	30	9	40
WLS 2 Resin	30	9	40
WLS 3 Resin	30	9	40
WGS Guard Bed Charcoal	8	36	3
WGS Delay Bed Charcoal	60	120	6
CVS Mixed Bed	50	18	33
CVS Cation Bed	50	36	17
SFS Resin	75	10	90

No radioactive filter sludges are generated.

Since as described in Table 11.4-10 the AP1000 incorporates two spent resin storage tanks, each with a nominal volume of 300 ft^3, the first point of BTP ETSB II-3 Position B.III is met. The on-site storage capacity for resin would typically be augmented by the use of a high integrity container, located in room 12374, which is the spent resin waste container fill station at the west end of the rail car bay of the auxiliary building.

As also described in DCD Table 11.4-1, the total expected solid radioactive waste generation rate is conservatively calculated to be 5759 ft^3 per year (5359 ft^3 per year excluding the resins discussed above), with a shipped volume of 1964 ft^3 per year (1454 ft^3 per year excluding resins). Handling of these wastes is described in DCD Section 11.4.2.1 and 11.4.2.3.

Low activity material, such as HVAC filters, ground sheets, boot covers, etc., will be packaged and stored before shipment in the radwaste building rooms 50351 and 50352. These rooms have a combined floor area of more than 2000 ft^2 and a combined volume of more than 25,000 ft^3, adequate for several years of waste storage.

Higher activity material, such as spent filter cartridges, are accumulated in the auxiliary building. Space is available within room 12374 (shared with the high integrity container for resin) and in room 12371, at the end of the rail bay.

These storage areas are adequate to meet items 2 and 3 of BTP ETSB II-3 Position B.III.

Design Control Document (DCD) Revision:

None

PRA Revision:

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

NRC Additional Comments:

Clarification is need in meeting the following requirements of BTP ETSB II-3 Position B.III

1. Storage areas for solidified wastes should be capable of accommodating at least 30 days waste generation at normal generation rates. These storage areas should be located indoors.

2. Storage areas for dry wastes and packaged containment equipment should be capable of accommodating at least one full offsite waste shipment.

Westinghouse Additional Response:

1. AP1000 does not incorporate waste solidification, but packaging of resin into high integrity containers (HIC's) may be considered analogous.

   A standard 158 ft^3 HIC with an internal capacity for resin of about 137 ft^3 and a 68.5 inch diameter footprint is assumed. With the 400 ft^3/year generation rate discussed above, one of these containers provides more than 120 days storage, which exceeds the 30 day requirement. The HIC will be located in room 12374.

2. As shown in DCD Table 11.4-1, the expected generation rate for compactible dry waste is 1010 ft^3/year, and the expected generation rate for non-compactible dry waste is 373 ft^3/year. These waste streams, totaling 1383 ft^3/year, will be boxed for truck shipment. Assuming use of standard boxes with an internal capacity of 90 ft^3 and external dimensions of 47(W) x 73(L) x 52(H) inches, about 15 boxes will be generated per year.

   These boxes will be stored in radwaste building rooms 50351 and 50352, which have a combined capacity of more than 20 storage positions (i.e., 80 boxes stacked four high). Thus the AP1000 has storage capacity for more than a year's accumulation.

   An expected truck shipment would be for a maximum of 28 of these boxes, so AP1000 has sufficient capacity for more than two offsite shipments, which exceeds the one shipment requirement.

Design Control Document (DCD) Revision:

None

PRA Revision:

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 620.001 (Response Revision 1)

Question:

DCD Rev. 0, pages Intro-8 and -9. The following documents are listed in Table 1-1 "Index of AP1000 Tier 2 Information Requiring NRC [Nuclear Regulatory Commission] Approval for Change": WCAP-14396, "Man-In-The Loop Test Plan Description," Rev. 2; WCAP-14401, "Programmatic Level Description of the AP-600 Human Factors Verification and Validation Plan," Rev. 2; WCAP-14701, "Methodology & Results of Defining Evaluation Issues for the AP600 Human System Interface Design Test Program," Rev. 1; and WCAP-14822, "AP600 Quality Assurance Procedures Supporting NRC Review of AP600 SSAR Sections 18.2 and 18.8," Rev. 0. The table lists the Tier 2 references for these documents as Chapter 18 and Table 1.6-1 of the DCD. However, DCD, Rev. 0, Table 1.6-1 does not cite these WCAPs nor does Chapter 18. In addition, DCD Rev. 0, Table 1.6-1 identifies materials referenced as Tier 2* that do not appear in Table 1-1. Please clarify and reconcile these discrepancies.

Westinghouse Response:

WCAP-14396 will be deleted from Table 1-1. The referenced report addressed concept test plans, per AP600 DCD Section 18.8.1.4 (deleted). Disposition of concept testing for AP1000 is addressed in RAI #620.008.

WCAP-14401 for AP600 has been replaced by WCAP-15860 for AP1000 (e.g. DCD Table 1.6-1). WCAP-15860 has been submitted to NRC by Reference 1. Table 1-1 will be revised accordingly.

WCAP-14701 will be deleted from Table 1-1. The referenced report addressed a design test program composed of concept testing and validation testing. Disposition of concept testing for AP1000 is addressed in RAI #620.008. Dispositions of testing issues identified in WCAP-14701 are addressed in RAI #620.034.

WCAP-14822 for AP600 has been replaced by WCAP-15847 for AP1000 (e.g. DCD Table 1.6-1). WCAP-15847 has been submitted to NRC by Reference 2. Table 1-1 will be revised accordingly.

<u>References</u>

1) Westinghouse Letter DCP/NRC1497, "Transmittal of WCAP-15860"Programmatic Level Description of the AP1000 Human Factors Verification and Validation Plan" Revision 0 dated April 15, 2002.

2) Westinghouse Letter DCP/NRC1500, "Transmittal of WCAP-15847, "AP1000 QA Procedures Supporting NRC Review of AP1000 DCD Section 18.2 and 18.8" Revision 0" dated April 15, 2002.

Design Control Document (DCD) Revision:

From DCD Table 1-1 (cont.) on p. Intro-8:

WCAP-15860, "Programmatic Level Description of the AP1000 Human Factors Verification and Validation Plan," **Rev 0**	No	Chapter 18 Table 1.6-1
WCAP-14651, "Integration of Human Reliability Analysis with Human Factors Engineering Design Implementation Plan," Rev 2	No	Chapter 18 Table 1.6-1
WCAP-14695, "Description of the Westinghouse Operator Decision Making Model and Function Based Task Analysis Methodology," Rev 0	No	Chapter 18 Table 1.6-1
WCAP-15847, "AP1000 Quality Assurance Procedures Supporting NRC review of AP1000 SSAR Sections 18.2 and 18.8," Rev 0	No	Chapter 18 Table 1.6-1

PRA Revision:

None

NRC Additional Comments:

Westinghouse should include WCAP-14396 in Chapter 18 as Tier 2*.

Westinghouse Additional Response:

The DCD will be revised as shown to make WCAP-14396 Tier 2*.

Table 1-1 (Cont.)
Index of AP1000 Tier 2 Information Requiring NRC Approval for Change

Item	Expiration at First Full Power	Tier 2 Reference
First-Plant-Only and Three-Plant-Only Tests	As Discussed	14.4.6
WCAP-14396, "Man-in-the-Loop Test Plan Description," Rev 3	**No**	**Chapter 18 Table 1.6-1**
WCAP-15860, "Programmatic Level Description of the AP1000 Human Factors Verification and Validation Plan," Rev 0	No	Chapter 18 Table 1.6-1
WCAP-14651, "Integration of Human Reliability Analysis with Human Factors Engineering Design Implementation Plan," Rev 2	No	Chapter 18 Table 1.6-1

Table 1.6-1 (Sheet 19 of 20)

MATERIAL REFERENCED

DCD Section Number	Westinghouse Topical Report Number	Title
18.8	[*WCAP-15860*	*Programmatic Level Description of the AP1000 Human Factors Verification and Validation Plan, Revision 0, April 2002*]*
	[*WCAP-14695*	*Description of the Westinghouse Operator Decision Making Model and Function Based Task Analysis Methodology, July 1996*]*
	WCAP-14655	Designer's Input to the Training of the Human Factors Engineering Verification and Validation Personnel, Revision 1, August 1996
	WCAP-14690	Designer's Input to Procedure Development for the AP600, Revision 1, June 1997
	WCAP-10170	Emergency Response Facilities Design and V&V Process, April 1982
	WCAP-14694	Designer's Input to Determination of the AP600 Main Control Room Staffing Level, July 1996

	[*WCAP-14396*	*Man-In-The-Loop Test Plan Description," Revision 3, November 2002.*]*
18.9	WCAP-14690	Designer's Input to Procedure Development for the AP600, Revision 1, June 1997

18.8.1.4 Man-In-The-Loop Testing

An integral part of the human system interface design process is the conduct of man-in-the-loop engineering tests to obtain feedback from prototype design products early in the design process.

The use of engineering tests is a good engineering practice, which reflects an iterative design process. By providing feedback early, before the detailed design is complete, engineering tests can help to improve the design and to avoid problems in the final product. Engineering tests also may offer concrete insight on questions that cannot be resolved logically (for example, by guidance or analysis). Finally, results from engineering tests provide evidence of design adequacy. Engineering tests thus serve to increase confidence and reduce project risk in the design process.

Engineering tests are performed to obtain empirical results that can be applied directly to understanding and improving the design product. More specifically, engineering tests are designed to produce the following types of results for the prototype design:

- **Design-specific operating experience**
- **Confirmation of necessary performance and integration**
- **Identification of specific problems**
- **Subjective feedback from expert users and observers**

[*The man-in-the-loop test plan to obtain feedback from prototype design products early in the design process is defined and documented in Reference 46.*]* The results of the engineering testing are used to refine the design of the operation and control centers system and the human system interface.

***NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.**

18.8.6 References

[*46. WCAP-14396, "Man-In-The-Loop Test Plan Description," Revision 3, November 2002.*]*

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 620.018 (Response Revision 1)

Question:

DCD Rev. 0, pages 18.1-2 and 18.1-3. The "annotated outline" titles of the chapter should be modified if they are to remain in agreement with current NRC guidance, NUREG-0711, Rev. 1, May 2002.

Westinghouse Response:

Sections 18.13, "Design Implementation", and 18.14, "Human Performance Monitoring", will be added to satisfy NUREG-0711 Rev 1.

Section 18.13 will be mapped to the existing activities denoted "Issue Resolution Verification" and "Final Plant HFE Verification" in Section 18.11. The applicable portion of NUREG-0711 Rev.1 Section 12 (specifically, 12.4.6) is equivalent to the combined Sections 11.4.5 and 11.4.6 of the original NUREG-0711. This input was previously reviewed and found acceptable; it therefore satisfies current guidance. This mapping approach will preserve consistency within the existing DCD document.

Section 18.14 will be incorporated as a COL action item, in similar fashion to Procedure Development (18.9) and Training Program Development (18.10).

Design Control Document (DCD) Revision:

[in DCD Section 18.1]

...

Section 18.9, Procedure Development - Reference 7 provides input to the Combined License applicant for the development of plant operating procedures, including information on the AP1000 emergency response guidelines and emergency operating procedures.

Section 18.10, Training Program Development - Reference 8 provides input from the designer on the training of the operations personnel who participate as subjects in the human factors verification and validation.

Section 18.11, Human System Interface Verification and Validation Program - [*Reference 9 presents a programmatic level description of the human factors verification and validation.*]*

Section 18.12, Inventory - presents the minimum inventory of controls, displays, and alarms present in the main control room and at the remote shutdown workstation. The design basis and the selection criteria used to identify the minimum inventory are presented.
Section 18.13, Design Implementation – In accordance with Reference 1, this issue is addressed under Section 18.11 as "Issue Resolution Verification" and "Final Plant HFE Verification".
Section 18.14, Human Performance Monitoring – Human performance monitoring applies after the plant is placed in operation, and is a Combined License applicant responsibility.

[in DCD Section 18.2.5]

*[The human factors engineering program is performed in accordance with the human factors engineering process specified in NUREG-0711 (Reference 1).]** Figure 18.1-1 shows the elements of the AP1000 human factors engineering program. *[These elements conform to the elements of the Program Review Model specified in Reference 1,* ***as augmented by Reference 7.]****

Human factors engineering Program Management is addressed in Section 18.2. The remaining elements are addressed in Sections 18.3 through 18.11, **18.13, and 18.14.**

These sections address the activities conducted as part of the **corresponding** human factors engineering element, **including** the accepted industry standards, guidelines, and practices used as technical guidance, the inputs to the element, and the products, including documents that are generated as output. The facilities, equipment, and tools employed are also addressed in the section corresponding to each element.

Operating Experience Review (**Section 18.3**) and Functional Requirements Analysis and Function Allocation (**Section 18.4**) are completed. Implementation plans are provided for Task Analysis (**Section 18.5**), Integration of Human Reliability Analysis (**Section 18.7**) and Human System Interface Design (**Section 18.8**). Staffing (**Section 18.6**), Procedure Development (**Section 18.9**), Training Development (**Section 18.10**), **and Human Performance Monitoring (section 18.14)** are Combined License applicant responsibilities. A programmatic level description is provided for Human Factors Verification and Validation (**Section 18.11**). **Human Factors Verification and Validation also addresses the activities identified under Design Implementation (Section 18.13).**
...

[in DCD Section 18.2.7]
...
[7. NUREG-0711, Rev.1, "Human Factors Engineering Program Review Model," U.S. NRC.]*

[in DCD Sections 18.13 and 18.14]

18.13 Design Implementation

This process element is added by Reference 2 to the Program Review Model specified in Reference 1. However, it mostly applies to plant modernization. The portions of the added element that apply to new plants were formerly addressed under the Verification and Validation element in Reference 1. Since these aspects of the Program Review Model are unchanged, AP1000 will continue to address them under Section 18.11 as "Issue Resolution Verification" and "Final Plant HFE Verification".

18.13.1 References

1. NUREG-0711, "Human Factors Engineering Program Review Model," U.S. NRC.
2. NUREG-0711, Rev.1, "Human Factors Engineering Program Review Model," U.S. NRC.

18.14 Human Performance Monitoring

Human performance monitoring applies after the plant is placed in operation, and is a Combined License applicant responsibility. Guidance and additional information on the objectives, scope, and methods of such programs are presented in Element 13 of Reference 1.

18.14.1 References

1. NUREG-0711, Rev.1, "Human Factors Engineering Program Review Model," U.S. NRC.

PRA Revision:

None

NRC Additional Comments:

Update references to NUREG 0711 to be consistent.

Westinghouse Additional Response:

The references to NUREG-0711 in DCD in Revision 3 were reviewed for consistency and will be changed as shown below.

In addition, Westinghouse notes that the COL commitment for human performance monitoring that was added to DCD 18.14 should have also been added to DCD Table 1.8-2. The addition of this item to Table 1.8-2 is also shown below.

Design Control Document (DCD) Revision:

Table 1.8-2 (Sheet 6 of 6)

SUMMARY OF AP1000 STANDARD PLANT COMBINED LICENSE INFORMATION ITEMS

Item No.	Subject	Subsection
18.9-1	Procedure Development	18.9.1
18.10-1	Training Program Development	18.10.1
18.11-1	Verification and Validation of AP1000 Human Factors Engineering Program	18.11.1
18.14-1	**Human Performance Monitoring**	**18.14**
19.59.10-1	As-built SSC HCLPF comparison to seismic margin evaluation	19.59.10.5

18.1.1 References

[2. NUREG-0711, "Human Factors Engineering Program Review Model," U.S. NRC, July 1994.]*

18.2.7 References

[7. *NUREG-0711, Rev. 1, "Human Factors Engineering Program Review Model," U.S. NRC, May 2002.*]*

18.4.2 References

1. NUREG-0711, "Human Factors Engineering Program Review Model," U.S. NRC, July 1994.

18.5.5 References

[*1. NUREG-0711, "Human Factors Engineering Program Review Model," U.S. NRC, July 1994.*]*

18.8.6 References

[29. *NUREG-0711, "Human Factors Engineering Program Review Model," U.S. NRC, July 1994.*]*