Entergy

Entergy Operations, Inc.
1448 S.R. 333
Russellville, AR 72802
Tel 501 858 5000

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Subject: Arkansas Nuclear One - Unit 2
Docket No. 50-368
License No. NPF-6
Response to Follow-up Request for Additional Information on Mechanical and Civil Engineering Issues Regarding the Power Uprate License Application

Gentlemen:

Entergy Operations, Inc. submitted an "Application for License Amendment to Increase Authorized Power Level," on December 19, 2000 (2CAN120001). In a letter dated August 23, 2001 (2CAN080104), Entergy responded to a request for additional information from the Nuclear Regulatory Commission (NRC) regarding the license application. Subsequent to review of the August 23, 2001 letter, the staff asked seven additional questions. The proposed responses were discussed with the staff during a teleconference on November 7, 2001. Written responses are provided in the attachments.

Attachment 1 contains responses to all seven questions; however, the response to question seven is missing selective information because the information is proprietary to Westinghouse Electric Company, LLC. A complete, but proprietary, response to question 7 is included as Attachment 2. An affidavit signed by Westinghouse, the owner of the information is provided in Attachment 3. The affidavit sets forth the basis on which the information may be withheld from public disclosure by the NRC and addresses the considerations listed in paragraph (b)(4) of Section 2.790 of *the Code of Federal Regulations*. Accordingly, it is respectfully requested that the information proprietary to Westinghouse be withheld from public disclosure in accordance with 10CFR2.790.

Correspondence regarding the proprietary aspects of the information contained in Attachment 2 should be addressed to Mehran Golbabai, Project Manager, ANO-2 power uprate, Westinghouse Electric Company, CE Nuclear Power LLC, 2000 Day Hill Road, Windsor, CT 06095.

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Attachment 4 contains excerpts from a pressurizer spray line calculation to support the response to NRC Question 4.

This submittal contains no regulatory commitments.

I declare under penalty of perjury that the foregoing is true and accurate. Executed on November 17, 2001.

Very truly yours,

Glenn R. Ashley

Glenn R. Ashley
Manager, Licensing

GRA/dwb
Attachments

cc: Mr. Ellis W. Merschoff
Regional Administrator
U. S. Nuclear Regulatory Commission
Region IV
611 Ryan Plaza Drive, Suite 400
Arlington, TX 76011-8064

NRC Senior Resident Inspector
Arkansas Nuclear One
P.O. Box 310
London, AR 72847

Mr. Thomas W. Alexion
NRR Project Manager Region IV/ANO-2
U. S. Nuclear Regulatory Commission
NRR Mail Stop 04-D-03
One White Flint North
11555 Rockville Pike
Rockville, MD 20852

Mr. Mehran Golbabai
Project Manager, ANO-2 power uprate Project
Westinghouse Electric Company
CE Nuclear Power, LLC
2000 Day Hill Road
Windsor, CT 06095

Attachment 1

Responses to Staff Questions on Mechanical and Civil Engineering Issues From the August 23, 2001, Letter Regarding the Power Uprate License Application

NRC Question 1

Attachment 2, page 3 of 17: Provide a summary discussion of how the new normal operating, seismic, and loss-of-coolant accident loads on the reactor coolant system (RCS) were determined prior to the replacement steam generator (RSG) analysis and power uprate. Provide a comparison of these loads for the original steam generator (OSG) and RSG conditions.

ANO Response

The new operating loads were determined as the new Dead Weight, new Thermal Expansion, and revised Thermal Transient loads. With respect to dead weight, the new RSG weight was the primary contributor. The power uprate conditions were used to determine revised thermal loads in the RCS piping. Overall changes in the RCS thermal movements were negligible. The RCS with RSG was analyzed for both seismic operating basis earthquake (OBE) and seismic safe shutdown earthquake (SSE) loads applying the original RCS support time histories to the revised RCS model. The resultant motions and loads became input into the component evaluations which consisted of the supports, RCS piping, reactor vessel, reactor vessel internals, fuel, head area equipment, RSG, reactor coolant pumps and motors and the tributary and secondary lines. Leak-before-break (LBB) was invoked for ANO-2 effectively eliminating the large break loss-of-coolant accidents (LOCAs).

Five controlling breaks (surge line, safety injection line, shutdown cooling line, main steam line and feedwater line) were considered. Based on extensive analyses of these lines, both terminal end and intermediate break locations were specified and considered in the LBB analysis of the RCS. Additional loads specified were the reactor vessel blowdown loads, thrust loads, jet impingement loads and steam generator cavity pressurization loads. The RCS was then analyzed using a non-linear finite element analysis model (ANSYS, similar to Seismic Model) to determine the loads and the motions throughout the entire RCS and into the branch lines.

Changes in the loads on the RCS due to the RSGs did not occur uniformly. With both RSG and power uprate considered, the largest increase in thermal expansion loads in the hot and cold legs was determined to be less than 15%. The largest increase in the dead weight loads was on the steam generator supports due to the weight increase. It was approximately 12%. Seismic response loads changed within a plus or minus 10% band, again being well within allowables. The elimination of the large break LOCA events resulted in major decreases in loads throughout the RCS. However, the recent evaluations also considered asymmetric LOCA loads on the head area equipment (e.g., control element drive mechanisms and incore instrument nozzles). Resultant Faulted Load loads were still acceptable. The largest impact of the new LBB loads was on the reactor coolant pump snubbers (in the earlier analyses LOCA loads had not been imposed on the RCS piping/reactor coolant pumps and supports).

NRC Question 2

Attachment 2, page 3 of 17: Provide a list of RCS structural models used in the RSG analysis and a summary describing how these models were used and the loading combinations that were considered in the analysis.

ANO Response

There were a total of two (2) RCS models, one for seismic and one for the branch line pipe break (BLPB) analyses. Dead Weight and Thermal loads were extrapolated using previous results by simply applying weight ratios or temperature ratios. The two RCS models were analyzed using ANSYS and were benchmarked against the original analysis. From the seismic and the BLPB runs, OBE, SSE and enveloping type BLPB loads were generated in tabular form. These were summarized for each component in a Load Summary Document that also included tabulations of the normal operating pressure loads. The various loads for the RSGs were combined for the various load cases (Design and Primary plus Secondary, Upset, Emergency and Faulted) and compared with the specified loads for the RCS with the OSGs. In cases where the new loads were enveloped by the original analysis, the original loads were retained. In cases where the new loads exceeded the old ones, the new loads typically were increased by up to 20% (to allow for future load increases) and were used to revise the component specifications. The component specifications were then used as the input to revise the stress analyses for the individual components.

Time histories computed throughout the RCS were converted into response spectra or were used as time histories for further, more detailed analyses of the reactor vessel internals, fuel, head area equipment, RSGs, and tributary lines. For this purpose, separate finite element models were used. With respect to the fuel, the following applies. First, a detailed reactor vessel internals model with fuel representation was used in conjunction with the seismic and LOCA motions computed earlier using the entire RCS model. Separate horizontal and vertical models were used. These analyses provided detailed results for the reactor vessel internals. They also provided vertical and horizontal seismic and LOCA time histories for both the fuel alignment plate and the core support plate. Detailed, non-linear representations of longer and shorter rows of fuel assemblies were used for the core analyses. Different numbers of fuel assemblies were considered and the gaps between fuel assemblies and between the fuel assemblies and core shroud were modeled. Time history analysis outputs consisted of spacer grid impact loads (both one-sided and through-grid type loadings) and actual fuel assembly deflections. The results were used to evaluate the grid strength and the fuel assembly guide tube stresses. Although the original analysis of the fuel did not consider horizontal LOCA motions, implementation of LBB for ANO-2 kept the LOCA impact loads quite low. Combined seismic SSE and LOCA grid impact loads were approximately 60% of the grid strength values that have been determined experimentally.

NRC Question 3

Attachment 1, page 8 of 24: You indicated that all the piping reanalysis is done in accordance with the 1980 Code for the RSG and power uprate, while the Code of record is ASME Code 1971 Edition through Summer 1972 Addenda. Confirm whether and how the use of 1980 Edition can be justified in accordance with 10CFR50.55a (c)(3) and Code Subsection NCA-1140.

ANO Response

Re-analyses for Class 1 piping for safety injection, shutdown cooling, and pressurizer spray were the result of the replacement steam generator effort, not power uprate; these analyses were performed in accordance with 1980 ASME Boiler & Pressure Vessel Code, Section III, NB-3600. A Code reconciliation was required since the Code of record is 1971 ASME B&PV Code through the summer 1972 Addenda. The piping analysis Code reconciliation only applies to the piping stress analysis, complies with NCA-1140, and is consistent with the rules of 10CFR50.55a (c)(3) in that the ASME Code has been accepted by the NRC. The following is from the piping analysis Code reconciliation included in the calculation.

> The changes made to indices and stress equations from the Code of Record to the 1980 Code are consistent with better understanding of piping stress. This understanding is derived from test and detailed finite element analysis. Using a more recent Code edition is not a problem since the analytical methods are not connected to evolving fabrication practices. The indices are established for standard piping components and weld types and changes in the specification of the components or welds are only allowed if it can be shown that the indices are unaffected. Since the more recent Code edition has more joint types (definition of geometry for group or type of joint) than the older Code edition, some review is required to determine into which joint type in the more recent Code edition a joint fits. Since mixing codes is not recommended, all the piping reanalysis is performed in accordance with the 1980 Code.
>
> Allowables from the Code of record were used because the materials were tested and certified to meet the Code of record. 1980 Code allowables were permissible if the yield and ultimate are equal to those of the 1971 Code through Summer 1972 Addenda.
>
> Generally, the ASME concurs with the use of more recent Code editions for stress analysis as long as the analyst is consistent and logical (ASME B&PV Section III 1986-NCA 1140). Therefore, the reanalysis was performed using the 1980 Code edition and the joint types were classified per the geometry limits in the 1980 Code. Allowables were taken either from the Code of Record or from the 1980 Code edition where yield and ultimate equal the Code of Record. This Code reconciliation complies with NCA-1140 and is consistent with the rules of 10CFR50.55a (c)(3).

This Code reconciliation complies with NCA-1140 and is consistent with the rules of 10CFR50.55a(c)(3).

NRC Question 4

Attachment 1, page 14 of 24: Provide a summary of the calculation for the stress and cumulative usage factor (CUF) at the elbow in the auxiliary spray line. Illustrate how you arrive to a CUF of 0.99, and also provide the calculation of the corresponding original stress and CUF.

ANO Response

Attachment 4 to this letter contains a copy of the calculation summary sheets from the stress calculation of the stress and cumulative usage factor (CFU) at the elbow in the auxiliary spray line. Attachment 4 also contains a copy of detailed definition of transients and type of transients. It should be noted that re-analysis of the pressurizer spray line (main spray & auxiliary spray) was the result of the replacement steam generator effort, not power uprate. Additionally, in anticipation of a license extension for ANO-2, the piping was qualified for 60 years (CUF is calculated based on 60-year life).

The total cumulative usage factor (CUF) of 0.99 for the Auxiliary Spray Joint 108 is determined based on the following:

Auxiliary Spray Joint 108

States of Stress	Usage
13 to 14	0.3062
12 to 14	0.1340
14 to 20	0.3302
14 to 17	0.1204
17 to 21	0.0026
19 to 21	0.0015
18 to 19	0.0032
8 to 19	0.0405
8 to 16	0.0063
Subtotal	0.9450
*Previous Fatigue (refueling outage to refueling outage)	0.463
Total	**0.9913**

* Previous fatigue is due to snubber lock-ups from startup to 2R9. No further lock-ups are expected since mechanical snubbers have been replaced with hydraulic units.

General notes:

1. States of stress 12 & 13 are representations of a transient which occurred and was addressed in a previous analysis.

2. The fatigue in this joint is conservatively high and could be reduced by doing a more detailed analysis; however, since it is less than 1.0, further analysis was considered unnecessary.

3. The transients which caused the high cumulative damage are not affected by power uprate.

NRC Question 5

Attachment 1, page 18 of 24: Regarding your evaluation of balance-of-plant piping, you indicated that a scaling factor was used to increase the stress or load calculated in the qualification of record by calculating the parameter increase. Provide a summary discussion of how you arrived to the scaling factors for the power uprate at various service conditions. Also, provide an example to illustrate how scaling factors were calculated and used in calculating the power uprate stresses and CUFs in relation to (1) dynamic loading due to fast valve closure transients, (2) creation of new high energy piping systems for high-energy line break/medium-energy line break (HELB/MELB) effects, and (3) nozzle qualification.

ANO Response

The process employed to establish the scaling factors used in the evaluations of the piping and pipe support qualifications for increases in the pressure and/or temperature values was adjusted on a case-by case basis depending on the specific analysis for that piping system. In general, it used the difference between the new pressure or temperature after power uprate and the pressure or temperature value used in the qualification of record. The new values of pressure and temperature used in the piping qualification for the various plant operating modes were determined in the ANO "pressure & temperature" (P-T) calculations. As a first pass, it was attempted to use the highest value reported in the P-T calculation for the applicable lines as the pressure or temperature to create a bounding qualification. If the analysis had insufficient margin to qualify the "bounding" values, the values for the specific modes were used in the applicable Code equations for the applicable loading combinations. The evaluations were performed in accordance with the applicable Code rules (ASME Section III Class 2, Class 3, or B31.1).

With the exception of piping located inside the condenser where the outside of the pipe may be at a vacuum, the component of stress contributed by pressure is a linear function of the internal pressure of the pipe. Where the pressure value increased, the pressure component of the applicable stress equations were scaled upward by a factor that was the ratio of the new pressure divided by the existing pressure. Where the piping was subject to an external pressure less than atmospheric, the factor was based on the differential pressure between the inside and the outside of the piping. The scaling factor was then used to calculate the amount of increase in stress caused by the pressure increase. This increase was then added to the calculated stress in the analysis of record to confirm that the new total stress including the applicable deadweight, sustained and occasional loads remained within the limits allowed by the Code.

An example of how a scaling factor was determined and used to evaluate pressure increases would be the following. The new pressure after power uprate is provided by the P-T calculation to be 390 psig. The qualification of record used a pressure of 370 psig.

The Code equation for the sustained load stress, S_{SL}, is:

$$S_{SL} = \frac{PD}{4t} + \frac{0.75iM_A}{Z} \leq 1.0S_h$$

where: P = Design Pressure
D = Outside diameter of the pipe
t = nominal wall thickness of the pipe
i = Stress Intensification Factor
M_A = Bending Moment due to deadweight and other sustained loads
Z = Section Modulus for the pipe
S_h = Allowable stress for the pipe material at the design temperature

The pressure component of the sustained stress equation is calculated by the formula:

$$\text{Pressure Stress} = \frac{PD}{4t}$$

Because the diameter and thickness of the pipe is not changed, the pressure stress term of the sustained stress increases by the ratio of the new pressure divided by the pressure used in the qualification of record. Thus, the scaling factor for the pressure stress is 390 psig / 370 psig = 1.055. The qualification of record calculated a sustained load stress of 6200 psi. That sustained load stress was made up of the pressure term stress of 3500 psi plus the deadweight and other sustained loads stress of 2700 psi. To calculate the new sustained stress, the pressure stress is multiplied by the scaling factor to get the new pressure stress of 1.055 X 3500 psi = 3693 psi. Because the deadweight and other sustained loads are not changing with power uprate, the new pressure stress is added to the original deadweight stress to yield the new total sustained load stress of 3693 psi + 2700 psi = 6393 psi. The piping in this example is SA-106 Grade B material that has an allowable stress of 15,000 psi at the design temperature. The new total stress of 6393 psi is below the allowable stress of 15,000 psi; therefore, the piping remains qualified for the sustained loads equation for the new pressure after power uprate. A similar calculation is done for the occasional loads stress, except that for the applicable Code equation, the pressure would be the peak pressure associated with the applicable occasional load level.

Because the stress caused by thermal expansion is a linear function of the range of temperature that the piping is exposed to, the new minimum and maximum temperature values and the minimum and maximum temperature values used in the qualification of record were used to determine the expansion coefficient for the specific temperature ranges and materials of the piping. The scaling factors for the thermal expansion stress were determined by the difference in the thermal expansion coefficient for the new temperature range divided by the thermal expansion coefficient for the temperature range used in the qualification of record. The calculated thermal expansion stress in the qualification of record was multiplied by the scaling factor to determine the new thermal expansion stress to confirm that the new total stress, including the pressure, deadweight, and sustained loads when applicable, remained within the limits allowed by the Code.

The same scaling factor used to evaluate the thermal expansion stress was also used to estimate the increase in support loads and nozzle loads for those supports and nozzles that restrain thermal expansion of the piping system. The qualification of record was evaluated to determine the effect of the load change and the available margin in the support or nozzle.

An example of how a scaling factor was determined and used to evaluate temperature increases would be the following.

The temperature after power uprate is specified in the P-T calculation to be 410 °F, and there is no change in the pressure. The qualification of record was performed for a temperature of 395 °F. The maximum thermal expansion stress in the qualification of record was reported as exceeding the allowable stress range for expansion stress alone, so the piping was qualified for the combined sustained plus thermal expansion stress. The combined sustained plus thermal expansion stress was reported to be 31,100 psi with an allowable stress of 37,500 psi. The thermal expansion portion of the combined stress was 23,305 psi, the pressure stress term was 4830 psi, and the deadweight and other sustained loads stress term was 2965 psi. The sustained loads terms (pressure and deadweight) were not affected by the increase in temperature, however, the thermal expansion term was affected. The qualification of record analyzed the piping for a temperature range of 70 °F to 395 °F, which yields a linear thermal expansion of 2.656 inches per 100 feet of pipe. The new temperature range, 70 °F to 410 °F, yields a linear thermal expansion of 2.792 inches per 100 feet of pipe. The thermal expansion stress term is then scaled up by the ratio of 2.792/2.656 = 1.05. The new thermal expansion stress range is then (1.05)(23,305 psi) = 24,471 psi. The new combined sustained plus thermal expansion stress is then 4830 psi + 2965 psi + 24,471 psi = 32,266 psi, which is less than the allowable stress of 37,500 psi, therefore, the piping remains qualified for the increase in temperature. The supports on this piping were all rod hangers, therefore, there were no lateral restraints to thermal expansion other than the vessel nozzle that the piping is attached to. Due to the piping configuration, the thermal expansion moved the piping in a direction that reduced the load on one of the rod supports, so that support was evaluated to verify that the additional temperature did not cause the piping to lift off the support. The qualification of record calculated a load change at that support of 318 pounds in the upward direction. The scaling factor was again used to determine the new thermal load change at that support to be (1.05)(318 lb) = 334 pounds. The deadweight load of the piping at that support is over 1350 pounds, therefore, after the thermal load change, the rod will still be supporting over 1000 pounds, therefore, the piping will not lift off the support, and the support remains qualified for the loads. The nozzle loads are a combination of forces and bending moments that the piping applies to the nozzle as a result of deadweight, other sustained loads, occasional loads, and thermal expansion loads. The manufacturer of the vessel provides allowable resultant forces and bending moments for each nozzle on the vessel. For this specific nozzle, the allowable resultant force is 19,644 pounds, and the allowable resultant moment is 18,498 ft-lb. The thermal portion of the applicable nozzle loads were increased by the 1.05 scaling factor resulting in a new resultant force of 2326 pounds and a new resultant bending moment of 14,657 ft-lb. This yields a combined interaction ratio of (2326/19,644) + (14,657/18,498) = 0.91, which is less than 1.0, and therefore remains qualified for the increased temperature.

The scaling factor was not used to correct the allowable stress value. Typically, the BOP piping is carbon steel, and the increase in temperature was small and had no significant effect on the allowable stress. For those piping systems where the temperature does affect the allowable stress, the new allowable stress was determined by direct linear interpolation of the values listed in the Code allowable stress tables for the specific material used.

Because this discussion was limited to BOP piping, ASME Class 1 design rules were not applicable, and Cumulative Usage Factors were not an element of the piping qualification. The ASME Class 2 and 3 and B31.1 design rules consider fatigue effects by use of "stress range reduction factors" that are used to reduce the allowable expansion stress when the predicted number of equivalent full temperature cycles exceeds 7000. While power uprate may have changed the specific temperature to which a piping system is qualified, it did not change the predicted number of thermal cycles, and the fatigue qualification of the BOP piping was not affected.

Scaling factors were not used on the piping that required evaluation of increased dynamic loading due to fast valve closure. Dynamic analysis of the major piping systems was evaluated for changes due to power uprate. As a result of process parameter changes such as mass flow rate, pressure and temperature resulting from the power uprate of ANO-2, new time-history forcing functions were calculated for the Main Steam piping due to the Stop Valve Fast Closure transient. These new forcing functions are documented in the ANO calculation system. The new forcing functions were evaluated and found to be bounded by the existing dynamic analysis forcing functions with the exception of the branch lines to the Moisture Separator Reheaters (MSRs) and to the Main Feed Water (MFW) pump drive turbines, and the piping between the stop/control valves and the HP turbine inlets. The branch lines to the MSRs and to the MFW pump drive turbines were reanalyzed for the new loads using the Bechtel ME101 finite element analysis computer program, and remain qualified to Code requirements. To reduce the nozzle loads on one of the feed water pump drive turbines, two spring supports will be adjusted to new load settings (scheduled for November 2001). Although stop valve fast closure dynamic loading was not included in the original design basis for the MS piping between the stop/control valves and the HP turbine inlets (originally supplied by General Electric as part of the main turbine-generator), the new dynamic forcing functions for power uprate conditions were calculated for this piping. The effects of the new dynamic loads on the piping between the stop/control valves and the HP turbine inlets, including the steam lead nozzle loads on the HP turbine casing, were evaluated and found to remain qualified to the stress and nozzle load limits. No other modifications are required to address the new dynamic loads and no other systems were identified that required revised dynamic analysis as a result of power uprate.

Scaling factors were not used to evaluate the creation of new high energy piping systems. The criteria for classification of a piping system as "high energy" at ANO Unit-2 is that any line that has an operating pressure that is greater than 275 psig, or an operating temperature greater than 200 °F is considered to be a high energy line. The revised pressures and temperatures specified in the P-T calculations for operation after power uprate were reviewed to identify any lines that experienced an increase that caused the new values to exceed the criteria for high energy classification. An example of this would be if a piping system originally had an operating pressure of 270 psig and an operating temperature of 195 °F, it would not be considered a "high energy" piping system. However, if the power uprate changed the operating pressure to 280 psig, or changed the operating temperature to 205 °F, it would now meet the criteria, and would be classified as a "high energy" piping system. That system would now be evaluated for High Energy Line Break hazards. At ANO, any line that is not classified as "high energy" is considered to be "moderate energy", and is evaluated for MELB. Because of this, pressure and temperature changes associated with power uprate could not create any new "moderate energy" piping systems.

Scaling factors were not used to evaluate the pressure design (hoop stress) of the piping systems. The approach taken regarding the pressure design qualification was to create a listing of all of the generic pipe size and wall thickness combinations, and for all the generic material types and grades specified in the piping class specifications. The maximum allowable pressure was then calculated by the applicable Code rules for each combination of diameter, wall thickness and material. Using this listing, the piping systems were reviewed to identify any lines that potentially have a pressure after power uprate that would exceed the allowable pressure for that line. It was verified that all lines satisfy the Code requirements for the pressure design of the piping.

NRC Question 6

Attachment 1, pages 20 & 21 of 24: Provide your basis for concluding that the potential for flow induced vibration, following the proposed power uprate, will not appreciably increase above the current recorded data at 100 percent power. Confirm whether, and how, vibration testing will be performed on the main steam line inside and outside the containment for the *power uprate. Also, describe the data to be measured, screening threshold criteria and acceptance criteria of vibration level for both carbon steel and stainless steel.*

ANO Response

The conclusion that power uprate changes will not create unacceptable flow induced vibration in the major main feed water and main steam piping was based on the velocity of the fluid flow inside the piping. The amount of flow induced vibration in a piping system is a function of the kinetic energy of the fluid that is flowing inside the piping, and the kinetic energy is a function of the linear velocity of the fluid as it flows through the piping. The higher the fluid velocity is, the higher the kinetic energy will be, and the more likely it is that a flow induced vibration problem could develop.

For the main feed water header piping, it was recognized that the design basis for the main feed water system provides excess capacity to allow operation of the plant at relatively high power levels with only one train of feed water in service. Since each individual train of feed water was designed with this extra capacity, the piping is sized to accommodate the increased mass flow rate associated with power uprate while maintaining a fluid flow velocity that is well within recommended ranges. It was also considered that ANO has successfully operated with a single train of feed water in service at these higher velocities without observing any unacceptable flow induced vibration of the piping. The conclusion with regard to the main feed water piping was thus based on the normal flow velocity of the feed water remaining within industrial accepted limits, and the proven capacity demonstrated by past operating experience.

For the main steam header piping, the linear velocity of the steam is a function of the pressure, temperature, and the mass flow rate of the steam. Because the plant was operating with original steam generators in the degraded condition during Cycle 14, the main steam pressure and temperature at full power was lower than it will be after power uprate. The lower pressure translated into a higher specific volume for the steam, and this caused a higher flow velocity even at the lower mass flow rates. The results are that the flow velocity (and the kinetic energy) was higher during Cycle 14 than it will be after power uprate, and the flow velocity at the original design conditions (prior to operation with the degraded steam generators) was lower than it will be after power uprate. The vibration of the main steam header piping was acceptable during both the Cycle 14 operating conditions and the original design operating conditions. The conclusion with regard to the main steam header piping was thus based on the fluid velocity (kinetic energy) at power uprate operating conditions being bounded by acceptable operation during original design conditions and Cycle 14 conditions.

Although power uprate is not anticipated to create any unacceptable flow induced vibration based on the preceding discussion, the walk downs and testing are used to confirm acceptable conditions. General area walkdowns and data collection is used to identify piping with vibration that exceeds the screening threshold. The screening threshold of 0.5 inches per second vibratory motion is based on ASME/ANSI OM-3, "Operation and Maintenance Requirements for Preoperational and Initial Startup Vibration Testing of Nuclear Power Plant Piping Systems", and is used to identify piping that might have unacceptable vibration. The piping that has vibration motion that exceeds the threshold is evaluated by the structural analysis group to determine if the vibration is acceptable, or if corrective actions are required. Each piping configuration is unique, and requires a case-by-case evaluation to determine acceptability. The vibration "velocity" is a good measure to use as a screening threshold because it reflects both deflection and frequency; however, the relative deflection of the piping is used to perform the structural evaluation. The basic process to determine acceptability is to measure the deflection of the piping system so that the stress caused by the vibration deflection can be determined. That vibration stress is then evaluated to determine the effect it has relative to the Code allowable stress for sustained loading, and what effect it has on the fatigue life of the piping. The acceptance criterion then becomes the Code allowable stress for sustained loading, and the endurance limit stress provided in the Code fatigue curves. Since the Code qualification of the BOP piping does not normally use the ASME Class 1 Fatigue Curves, the following example is provided to show how a simplified structural evaluation might model the piping and apply the endurance limit stress level from the fatigue curves.

The stress in the pipe due to vibration deflection is a bending stress that follows the equation:

$$S = \frac{MD}{2I}$$

where: M = bending moment caused by the deflection
D = outside diameter of the pipe
I = moment of inertia for the pipe

Since most of the BOP piping is supported by springs and rods, it would typically be conservative to model the piping as a simply supported beam with a distributed load. For this configuration, the maximum bending moment and maximum deflection occurs at the mid-span with the following formulas.

$$M = \frac{wl^2}{8} \quad \text{and} \quad \Delta = \frac{5wl^4}{384EI}$$

where: M = maximum bending moment (located at the center of the span)
Δ = maximum deflection (located at the center of the span)
w = distributed weight of the piping
l = length of pipe in the span
E = modulus of elasticity = 28,000,000 psi
I = moment of inertia of the pipe

By rearranging these equations, the maximum deflection of a simply supported pipe for a given endurance stress limit can be calculated by the following formula:

$$\Delta = \frac{Sl^2}{4.8DE}$$

It may be seen from this formula that the maximum allowable deflection, Δ, will be smaller for the shortest length, smallest allowable stress, and the largest diameter of piping. For carbon steel pipe with an ultimate tensile strength less than 80,000 psi, the endurance limit specified by the Code is 12,500 psi, which is typically the lowest value that will be encountered in the major BOP piping systems. As an example, a ten-foot span of the 38-inch diameter MS piping would have a maximum deflection limit of more than 35 mils. The actual measured deflection of the main steam header piping due to vibration motion had very little change between cycle 14 and cycle 15. The relative deflection that contributes to bending stress has been less than 10 mils, and is considered acceptable by comparison to the allowable deflection of 35 mils calculated in the example.

Because the main feed water piping is smaller diameter than the main steam piping, the example above would yield a larger acceptable deflection limit for a ten foot simply supported span of feed water piping. Also, the endurance limit for stainless steel is higher than for carbon steel, so a simply supported ten foot span of stainless steel pipe would have a larger allowable deflection than the same carbon steel pipe.

While the general example above shows the elements of the structural evaluation, a specific evaluation may use more rigorous modeling and analysis methods to determine stress levels for the specific configuration and motion of the piping.

NRC Question 7

Attachment 2, Page 10 of 17: Provide a summary of the results for the stress, CUF and code allowables at limiting locations in the steam generator shell. Also, provide an example of a calculation to illustrate how you arrive at the calculated CUF value for the secondary side pressure boundary components following the power uprate.

ANO Response

Per phone call with NRC on November 7, 2001, the NRC clarified the request as follows: provide summary results for locations mentioned in notes 1 and 2 of Table 2-6 of Attachment 2, provide a summary/example calculation for the location reported with CUF of [ ], and provide further information relative to location and loading condition for the reported Design Condition Pm + Pb = [ ] ksi result. The attached Table 1 provides the requested additional stress results, cumulative usage factors (CUF), and ASME Code allowables for the limiting locations previously identified in Notes 1 and 2 of Table 2-6 of Attachment 2. The results demonstrate that the maximum stress intensities and cumulative fatigue usage factors are in compliance with the ASME Code requirements.

As identified in Table 1, the reported case where the calculated Design Condition Pm + Pb (primary membrane plus bending stress intensity) has a value of [ ] ksi versus an allowable of [ ] ksi is for a location involving the channel head support pedestal. Specifically, the reported result is at the location where the channel head forging transitions into the upper cylindrical section of the support pedestal. The Design Condition loadings included in the evaluation of this location are primary side pressure applied to the inside surface of the channel head plus the support pedestal external loads due to deadweight, thermal, and seismic (OBE). Stress states due to the applied loads have been calculated using finite element analysis. It is noted that the external loads used in the evaluation are the conservative loads provided in the steam generator certified design specification (i.e., the design loads are significantly greater than those calculated in the reactor coolant system analysis). It is additionally noted that a portion [ ] of the reported primary stress intensity is actually secondary in nature since it is due to achieving displacement compatibility between the channel head under internal pressure and the pedestal which is not loaded by pressure and is constrained approximately 30 inches away from the channel head. Thus, the reported result which shows that the calculated stress intensity is only slightly less than the Code allowable, is due in part to the conservatisms in the evaluation.

As identified in Table 1, the reported case where the calculated cumulative fatigue usage factor is [ ] is for the bolts used for the 3-inch diameter inspection ports. Detailed finite element analysis was performed for the inspection port, including the bolts. Loadings evaluated in the analysis included preload, pressure, and thermal transients. Stresses were determined for the limiting times during each of the transients, and then maximum stress ranges and alternating stresses calculated for use in the fatigue analysis. The methods used in determining the limiting alternating stresses are those specified in NB-3000 of Section III of the ASME Code. The attached Table 2 provides the details of the fatigue usage calculation, including the limiting transient combinations, associated alternating stress, allowable cycles for that alternating stress consistent with the Section III fatigue curve, the applied cycles (number of cycles specified in the steam generator certified design specification), and the resulting fatigue usage. As shown in Table 2, the total calculated cumulative usage factor is [ ] which is reported as [ ] in Table 1. This calculated result, based on the use of conservatively defined transients and postulated number of cycles, is less than the Code allowable and thus demonstrates compliance with the ASME Code requirements.

Table 1
Summary of Steam Generator Structural Evaluations

Location	**Condition**	**Calculated Result**	**Code Allowable**

Table 1 (continued)
Summary of Steam Generator Structural Evaluations

Location	Condition	Calculated Result	Code Allowable

Table 1 (continued)
Summary of Steam Generator Structural Evaluations

Location	**Condition**	**Calculated Result**	**Code Allowable**

Table 1 (continued)
Summary of Steam Generator Structural Evaluations

Location	**Condition**	**Calculated Result**	**Code Allowable**

Table 1 (continued)
Summary of Steam Generator Structural Evaluations

Location	**Condition**	**Calculated Result**	**Code Allowable**

Table 2
Summary of Cumulative Fatigue Usage Factor For Inspection Port Bolt

Transient Combination	Alternating Stress (ksi)	Allowable Cycles (N)	Applied Cycles (n)	Usage Factor (n/N)

Attachment 2

Proprietary Response to NRC Question 7

Proprietary Response

Proprietary Response to NRC Question 7

NRC Question 7

Attachment 2, Page 10 of 17: Provide a summary of the results for the stress, CUF and code allowables at limiting locations in the steam generator shell. Also, provide an example of a calculation to illustrate how you arrive at the calculated CUF value for the secondary side pressure boundary components following the power uprate.

ANO Response

Per phone call with NRC on November 7, 2001, the NRC clarified the request as follows: provide summary results for locations mentioned in notes 1 and 2 of Table 2-6 of Attachment 2, provide a summary/example calculation for the location reported with CUF of **[0.996]**, and provide further information relative to location and loading condition for the reported Design Condition Pm + Pb = **[44.8]** ksi result. The attached Table 1 provides the requested additional stress results, cumulative usage factors (CUF), and ASME Code allowables for the limiting locations previously identified in Notes 1 and 2 of Table 2-6 of Attachment 2. The results demonstrate that the maximum stress intensities and cumulative fatigue usage factors are in compliance with the ASME Code requirements.

As identified in Table 1, the reported case where the calculated Design Condition Pm + Pb (primary membrane plus bending stress intensity) has a value of **[44.8]** ksi versus an allowable of **[45.0]** ksi is for a location involving the channel head support pedestal. Specifically, the reported result is at the location where the channel head forging transitions into the upper cylindrical section of the support pedestal. The Design Condition loadings included in the evaluation of this location are primary side pressure applied to the inside surface of the channel head plus the support pedestal external loads due to deadweight, thermal, and seismic (OBE). Stress states due to the applied loads have been calculated using finite element analysis. It is noted that the external loads used in the evaluation are the conservative loads provided in the steam generator certified design specification (i.e., the design loads are significantly greater than those calculated in the reactor coolant system analysis). It is additionally noted that a portion **[(greater than 10 ksi)]** of the reported primary stress intensity is actually secondary in nature since it is due to achieving displacement compatibility between the channel head under internal pressure and the pedestal which is not loaded by pressure and is constrained approximately 30 inches away from the channel head. Thus, the reported result which shows that the calculated stress intensity is only slightly less than the Code allowable, is due in part to the conservatisms in the evaluation.

As identified in Table 1, the reported case where the calculated cumulative fatigue usage factor is **[0.996]** is for the bolts used for the 3-inch diameter inspection ports. Detailed finite

Attachment 3

Affidavit for Proprietary Information Pursuant to 10CFR2.790
(for the information contained in Attachment 2)

<u>AFFIDAVIT PURSUANT TO 10 CFR 2.790</u>

I, Norton L. Shapiro, depose and say that I am the Chief Engineer, CE Engineering Technology, of Westinghouse Electric Company LLC (WEC), duly authorized to make this affidavit, and have reviewed or caused to have reviewed the information which is identified as proprietary and referenced in the paragraph immediately below. I am submitting this affidavit in conformance with the provisions of 10 CFR 2.790 of the Commission's regulations and in conjunction with the application of ENTERGY Operations, Inc. for withholding this information.

The information for which proprietary treatment is sought is contained in the following document:

Enclosure 1 to LTR-OA-01-56, "Response to Structural RAI No. 7", November 15, 2001

This document has been appropriately designated as proprietary.

I have personal knowledge of the criteria and procedures utilized by WEC in designating information as a trade secret, privileged or as confidential commercial or financial information.

Pursuant to the provisions of Section 2.790(b)(4) of the Commission's regulations, the following is furnished for consideration by the Commission in determining whether the information sought to be withheld from public disclosure, included in the above referenced document, should be withheld.

1. The information sought to be withheld from public disclosure, is owned and has been held in confidence by WEC. It consists of ANO-2 steam generator stress analysis model and results supporting power uprate.
2. The information consists of test data or other similar data concerning a process, method or component, the application of which results in substantial competitive advantage to WEC.
3. The information is of a type customarily held in confidence by WEC and not customarily disclosed to the public. WEC has a rational basis for determining the types of information customarily held in confidence by it and, in that connection, utilizes a system to determine when and whether to hold certain types of information in confidence.
4. The information is being transmitted to the Commission in confidence under the provisions of 10 CFR 2.790 with the understanding that it is to be received in confidence by the Commission.
5. The information, to the best of my knowledge and belief, is not available in public sources, and any disclosure to third parties has been made pursuant to regulatory provisions or proprietary agreements which provide for maintenance of the information in confidence.
6. Public disclosure of the information is likely to cause substantial harm to the competitive position of WEC because:
   a. A similar product is manufactured and sold by major pressurized water reactor competitors of WEC.
   b. WEC invested substantial funds and engineering resources in the development of this information. A competitor would have to undergo similar expense in generating equivalent information.
   c. In order to acquire such information, a competitor would also require considerable time and inconvenience to develop an ANO-2 steam generator stress analysis model and results supporting power uprate.
   d. The information consists of ANO-2 steam generator stress analysis model and results supporting power uprate, the application of which provides a competitive economic advantage. The availability of such information to competitors would enable them to modify their product to better compete with WEC, take marketing or other actions to improve their product's position or impair the position of WEC's product, and avoid developing similar data and analyses in support of their processes, methods or apparatus.
   e. In pricing WEC's products and services, significant research, development, engineering, analytical, manufacturing, licensing, quality assurance and other costs and expenses must be included. The ability of WEC's competitors to utilize such information without similar expenditure of resources may enable them to sell at prices reflecting significantly lower costs.
   f. Use of the information by competitors in the international marketplace would increase their ability to market nuclear steam supply systems by reducing the costs associated with their technology development. In addition, disclosure would have an adverse economic impact on WEC 's potential for obtaining or maintaining foreign licensees.

Further the deponent sayeth not.

N. L. Shapiro

Norton L. Shapiro
Chief Engineer, CE Engineering Technology

Sworn to before me
this 15 day of **November**, 2001

Laurie J. White

Notary Public
My commission expires: 8/31/04

Attachment 4

Calculation summary sheets from the stress calculation of the stress and cumulative usage factor (CFU) located at the elbow of the auxiliary spray line (pages 62-65)
and
Detailed definition of transients and type of transients (pages O-16 through O-29)

Attachment4.PDF

ANO-2 PRZR SPRAY LINE CLASS 1 STRESS ANALYSIS Dec. 1999

LOAD TABLE FOR EQ.11 AT LOCATION108 (STR)

LOAD SET NO	LOAD SET DESCRIPTION	NO. OF CYCLES	P	X *	Y *	Z *	DT1	DT2	TA	TB
1	1 OBE + SAM	200	.000	.0	.0	.0	.0	.0	304.0	304.0
2	2 PLANT HEAT UP	500	2.250	-.5	-.1	.2	.0	.0	304.0	304.0
3	3 PLANT LOADING +	15000	2.290	-.6	-.1	.2	.0	.0	374.0	374.0
4	4 PLANT LOADING -	15000	2.250	-.5	-.1	.2	.0	.0	374.0	374.0
5	5 10% STEP LOAD +	8000	2.150	-.6	-.1	.2	.0	.0	374.0	374.0
6	6 10% STEP LOAD -	8000	2.250	-.5	-.1	.2	.0	.0	374.0	374.0
7	7 REACTOR TRIP +	500	2.550	-.7	-.1	.2	.0	.0	374.0	374.0
8	8 RPV TRIP RAMP -	500	1.650	-.6	-.1	.2	.0	.0	374.0	374.0
9	9 REACTOR TRIP -	500	2.250	-.5	-.1	.2	.0	.0	374.0	374.0
10	10 PLANT UNLOADING	15000	2.225	-.5	-.1	.2	.0	.0	374.0	374.0
11	11PLANT COOLDOWN +	500	2.250	-.6	-.1	.2	.0	.0	374.0	374.0
12	12PLT COOLDOWN 479F	3	2.615	.5	1.7	9.5	66.0	11.0	429.0	297.0
13	13PLT COOLDOWN 479F	3	2.615	.5	1.7	9.5	292.0	62.0	429.0	297.0
14	14 SHUTDOWN	500	.000	.0	.0	.0	.0	.0	70.0	70.0
15	15 OBE + SAM	200	2.260	-.6	-.1	.2	.0	.0	304.0	304.0
16	16B-3a START	250	2.205	-.5	-.1	.2	86.0	16.0	164.0	143.0
17	17B-7a START	250	2.205	-.5	-.1	.2	159.0	33.0	183.0	154.0
18	18B-8a START	10	2.205	-.5	-.1	.2	-37.0	-7.0	103.0	113.0
19	19B-3 2 gpm TO 350F	250	2.205	.2	1.1	6.1	16.0	3.0	301.0	232.0
20	20B-7 44gpm TO 350F	250	2.205	.2	1.1	6.1	37.0	6.0	315.0	233.0
21	21B-8 44gpm TO 50F	10	2.205	-.4	-.2	-1.1	-9.0	-1.0	61.0	86.0

*NOTE: OBE AND SAM MOMENTS ARE INCLUDED IN RANGE VALUE CALCULATIONS NOT IN THESE SINGLE SET COMBINED MOMENTS.

ANO-2 PRZR SPRAY LINE CLASS 1 STRESS ANALYSIS Dec. 1999

SUMMARY OF PRIMARY LOAD AND EQ.9 STRESS AT LOCATION108 (STR)

LOAD SET NO	LOAD SET DESCRIPTION	CONDITION	P	MX	MY	MZ	SM	SY	ALLOW. STRESS	EQ.9 STRESS	STATUS
1	1 OBE + SAM	S	.000	1.6	1.8	3.8	19.98	21.89	29.97	6.90	P
2	2 PLANT HEAT UP	N	2.250	.1	.0	.4	19.98	21.89	32.84	6.41	P
3	3 PLANT LOADING +	N	2.290	.1	.0	.4	19.98	21.89	32.84	6.51	P
4	4 PLANT LOADING -	N	2.250	.1	.0	.4	19.98	21.89	32.84	6.41	P
5	5 10% STEP LOAD +	N	2.150	.1	.0	.4	19.98	21.89	32.84	6.15	P
6	6 10% STEP LOAD -	N	2.250	.1	.0	.4	19.98	21.89	32.84	6.41	P
7	7 REACTOR TRIP +	U	2.550	.1	.0	.4	19.98	21.89	32.84	7.19	P
8	8 RPV TRIP RAMP -	U	1.650	.1	.0	.4	19.98	21.89	32.84	4.86	P
9	9 REACTOR TRIP -	U	2.250	.1	.0	.4	19.98	21.89	32.84	6.41	P
10	10 PLANT UNLOADING	N	2.225	.1	.0	.4	19.98	21.89	32.84	6.35	P
11	11PLANT COOLDOWN +	N	2.250	.1	.0	.4	19.98	21.89	32.84	6.41	P
12	12PLT COOLDOWN 479F	N	2.615	.1	.0	.4	19.98	21.89	32.84	7.36	P
13	13PLT COOLDOWN 479F	N	2.615	.1	.0	.4	19.98	21.89	32.84	7.36	P
14	14 SHUTDOWN	N	.000	.1	.0	.4	19.98	21.89	32.84	.59	P
15	15 OBE + SAM	U	2.260	.9	.9	2.3	19.98	21.89	32.84	9.85	P
16	16B-3a START	N	2.205	.1	.0	.4	19.98	21.89	32.84	6.29	P
17	17B-7a START	N	2.205	.1	.0	.4	19.98	21.89	32.84	6.29	P
18	18B-8a START	N	2.205	.1	.0	.4	19.98	21.89	32.84	6.29	P
19	19B-3 2 gpm TO 350F	N	2.205	.1	.0	.4	19.98	21.89	32.84	6.29	P
20	20B-7 44gpm TO 350F	N	2.205	.1	.0	.4	19.98	21.89	32.84	6.29	P
21	21B-8 44gpm TO 50F	N	2.205	.1	.0	.4	19.98	21.89	32.84	6.29	P
22	1 WGT + P(D) + OBE	D	2.350	.9	.9	2.3	19.98	21.89	29.97	10.08	P
23	22 POST-HELB PRESS	F	2.742	.1	.0	.4	19.98	21.89	59.93	7.68	P
24	23 SSE	F	2.260	1.4	1.4	3.4	19.98	21.89	59.93	11.84	P
25	24 HELB	F	2.260	.1	.0	.4	19.98	21.89	59.93	6.44	P
26	25 SRSS(SSE+HELB)	F	2.260	1.4	1.4	3.4	19.98	21.89	59.93	11.84	P

ALLOWABLE STRESSES: FOR D & S =1.5SM; FOR N & U =1.8SM OR 1.5SY WHICHEVER SMALLER;
FOR E = 2.25SM OR 1.8SY WHICHEVER SMALLER; FOR F =3SM; ***SM & SY BASED ON DESIGN TEMP.

ANO-2 PRZR SPRAY LINE CLASS 1 STRESS ANALYSIS Dec. 1999

THIRTY HIGHEST VALUES OF S-N, AT LOCATION108 (STR)

LOAD SET: PAIR		S-N	EQ.12	EQ.13	3 SM	DT1	DT1 ALLOWABLE	STATUS	K-E
13	14	95.422	20.712	50.350	59.934	292.000	494.368	PASS	2.974
12	14	95.422	20.712	50.350	59.934	66.000	494.368	PASS	2.974
13	21	93.327	23.109	41.088	59.934	301.000	504.749	PASS	2.857
12	21	93.327	23.109	41.088	59.934	75.000	504.749	PASS	2.857
13	18	84.204	20.425	37.511	59.934	329.000	380.570	PASS	2.350
12	18	84.204	20.425	37.511	59.934	103.000	380.570	PASS	2.350
13	15	84.080	20.356	39.527	59.934	292.000	401.098	PASS	2.343
12	15	84.080	20.356	39.527	59.934	66.000	401.098	PASS	2.343
8	13	83.688	20.369	38.958	59.934	292.000	380.570	PASS	2.321
8	12	83.688	20.369	38.958	59.934	66.000	380.570	PASS	2.321
5	13	80.223	20.356	35.506	59.934	292.000	380.570	PASS	2.128
5	12	80.223	20.356	35.506	59.934	66.000	380.570	PASS	2.128
10	13	79.779	20.429	34.989	59.934	292.000	380.570	PASS	2.104
10	12	79.779	20.429	34.989	59.934	66.000	380.570	PASS	2.104
9	13	79.601	20.425	34.816	59.934	292.000	380.570	PASS	2.094
9	12	79.601	20.425	34.816	59.934	66.000	380.570	PASS	2.094
6	13	79.601	20.425	34.816	59.934	292.000	380.570	PASS	2.094
6	12	79.601	20.425	34.816	59.934	66.000	380.570	PASS	2.094
4	13	79.601	20.425	34.816	59.934	292.000	380.570	PASS	2.094
4	12	79.601	20.425	34.816	59.934	66.000	380.570	PASS	2.094
2	13	79.601	20.425	34.816	59.934	292.000	401.098	PASS	2.094
2	12	79.601	20.425	34.816	59.934	66.000	401.098	PASS	2.094
11	13	79.538	20.362	34.816	59.934	292.000	380.570	PASS	2.090
11	12	79.538	20.362	34.816	59.934	66.000	380.570	PASS	2.090
3	13	79.257	20.356	34.540	59.934	292.000	380.570	PASS	2.075
3	12	79.257	20.356	34.540	59.934	66.000	380.570	PASS	2.075
7	13	77.455	20.350	32.745	59.934	292.000	380.570	PASS	1.974
7	12	77.455	20.350	32.745	59.934	66.000	380.570	PASS	1.974
13	16	70.898	20.425	30.119	59.934	206.000	380.570	PASS	1.610
12	16	70.898	20.425	30.119	59.934	20.000	380.570	PASS	1.610

ANO-2 PRZR SPRAY LINE CLASS 1 STRESS ANALYSIS Dec. 1999

SUMMARY OF CALCULATIONS OF CUMULATIVE USAGE FACTOR AT LOCATION108 (STR)

LOAD PAIR: I	LOAD PAIR: J	EQ.11 S-P	K-E	EQ.14 SP*KE/2	OCCURENCE N-I	OCCURENCE N-J	N	SET ELIMINATED	CYCLES LEFT N-I	CYCLES LEFT N-J	ALLOW. CYCLES N-D	FATIQUE USAGE FACTOR
13	14	435.884	2.974	648.104	3	500	3	13,13	0	497	9	.3062
12	14	303.028	2.974	450.564	3	497	3	12,12	0	494	22	.1340
14	20	198.588	1.204	119.591	494	250	250	20,20	244	0	757	.3302
14	17	177.811	1.000	88.905	244	250	244	14,14	0	6	2026	.1204
17	21	172.427	1.000	86.213	6	10	6	17,17	0	4	2276	.0026
19	21	166.346	1.000	83.173	250	4	4	21,21	246	0	2607	.0015
18	19	158.027	1.000	79.013	10	246	10	18,18	0	236	3164	.0032
8	19	135.254	1.000	67.627	500	236	236	19,19	264	0	5820	.0405
8	16	88.450	1.000	44.225	264	250	250	16,16	14	0	39921	.0063
8	15	22.421	1.000	11.211	14	200	14	8, 8	0	186	>1.E6	0
1	1	19.417	1.000	9.709	200	200	200	1, 1	0	0	>1.E6	0
7	15	15.751	1.000	7.876	500	186	186	15,15	314	0	>1.E6	0
5	7	8.346	1.000	4.173	8000	314	314	7, 7	7686	0	>1.E6	0
3	5	2.900	1.000	1.450	15000	7686	7686	5, 5	7314	0	>1.E6	0
3	10	2.029	1.000	1.014	7314	15000	7314	3, 3	0	7686	>1.E6	0
10	11	1.145	1.000	.572	7686	500	500	11,11	7186	0	>1.E6	0
9	10	.559	1.000	.280	500	7186	500	9, 9	0	6686	>1.E6	0
6	10	.559	1.000	.280	8000	6686	6686	10,10	1314	0	>1.E6	0
4	6	.000	1.000	.000	15000	1314	1314	6, 6	13686	0	>1.E6	0
2	4	.000	1.000	.000	500	13686	500	2, 2	0	13186	>1.E6	0

TOTAL USAGE FACTOR= .9450

STRESS INDICES FOR108 (STR)

B1	C1	K1	B2	C2	K2	C3	C3P	K3
.75	2.00	3.00	1.50	2.10	2.00	1.80	1.00	3.00

O-3 Definition of Transients

ABB/CE Design Basis Document No. 011-ST98-DB-018, Rev. 0, contains two types of Transients for the Main Spray and Auxiliary Spray Line: the so-called A-types of Transients and the so-called B-types of Transients. These two types of Transients are presented here below and on the following pages.

A-types of Transients
from Page E5 of the AAB/CE Design Basis Document
No. 011-ST98-DB-018, Rev. 0

A-1: 500 occurrences of Plant Trips
A-2 and **A-3**: a total of 23,000 occurrences of Plant Loading Ramps and Step Loads.

When comparing with the Transients listed on Page J-4 (Class 1 Stress Analysis Certification) and in the Tables of Pages J-28 and J-29 of the previous release of this Document (FTI Doc. No. 32-5004353-00), it can be seen that these Transients are the Classical Transients analyzed in that previous release, except for the absence of the Cooldown Transients which are now contained inside the B-types of Transients listed below.

Prepared By RJG. Date 3/23/00.
Reviewed By LT Date 3/23/00

B-types of Transients
from the AAB/CE Design Basis Document No. 011-ST98-DB-018, Rev. 0

There are eight B-type Transients. They are described in detail on Pages E5 through E8 of the ABB/CE Design Basis Document (Ref. O-3).

The Table below gives an overview of those eight Transients. The full descriptions of these eight Transients are given in the next eight pages, which use information from both the ABB/CE Specification (Ref. O-3) and of the previous Main Spray Line Stress Analysis performed by ABB/CE (Ref. O-4).

Overview of the B-type Transients [so-called "Thermal Stratification"]

Transient Numbers [Number of cycles]	Time of occurrence	PRZR Initial Temp.	Pressure (psia.)	Initial Conditions in the uppermost horizontal section of the Main Spray Line	Main Spray Initiation	Auxiliary Spray Initiation
B-1 [500]	during Heat-up, or cooldown	475	539	2 gpm 300^0 F. Main Spray	250 gpm 400^0 F.	-----
B-2 [500]	during Heat-up, or cooldown	650	2205	2 gpm 475^0 F. Main Spray	250 gpm 575^0 F.	-----
B-3 [250]	cooldown, or NCC	650	2205	No Flow and 650^0 F. Steam	-----	2 gpm 350^0 F.
B-4 [80]	steam bubble formation	480	565	No Flow and 480^0 F. Steam	2 gpm 120^0 F.	-----
B-5 [10]	NCC	650	2205	No Flow and 650^0 F. Steam	-----	2 gpm 50^0 F.
B-6 [500]	cooldown	550	1044	100 gpm 435^0 F. Main Spray	Main Spray is secured (zero)	-----
B-7 [250]	cooldown	650	2205	No Flow and 650^0 F. Steam	-----	44 gpm 350^0 F.
B-8 [10]	cooldown, or NCC	650	2205	No Flow and 650^0 F. Steam	-----	44 gpm 50^0 F.

Notes:

1.) NCC = Natural Circulation Cooldown

2.) all the above transients are categorized as Normal condition, except for B-5 and B.8, which are now reclassified as "Emergency", and therefore do not need to be considered in the Fatigue/Stress Analysis.

3.) due to the high gpm values, B-6, B-7 and B-8 do not experience any thermal stratification.

4.) from the thermal stratification transients B-1 through B-5:
- for B-1 and B-2, the initial stratification condition gets washed out;
- for B-3 through B-5, a "No Flow" condition is replaced by a low gpm flow which produces thermal stratification.

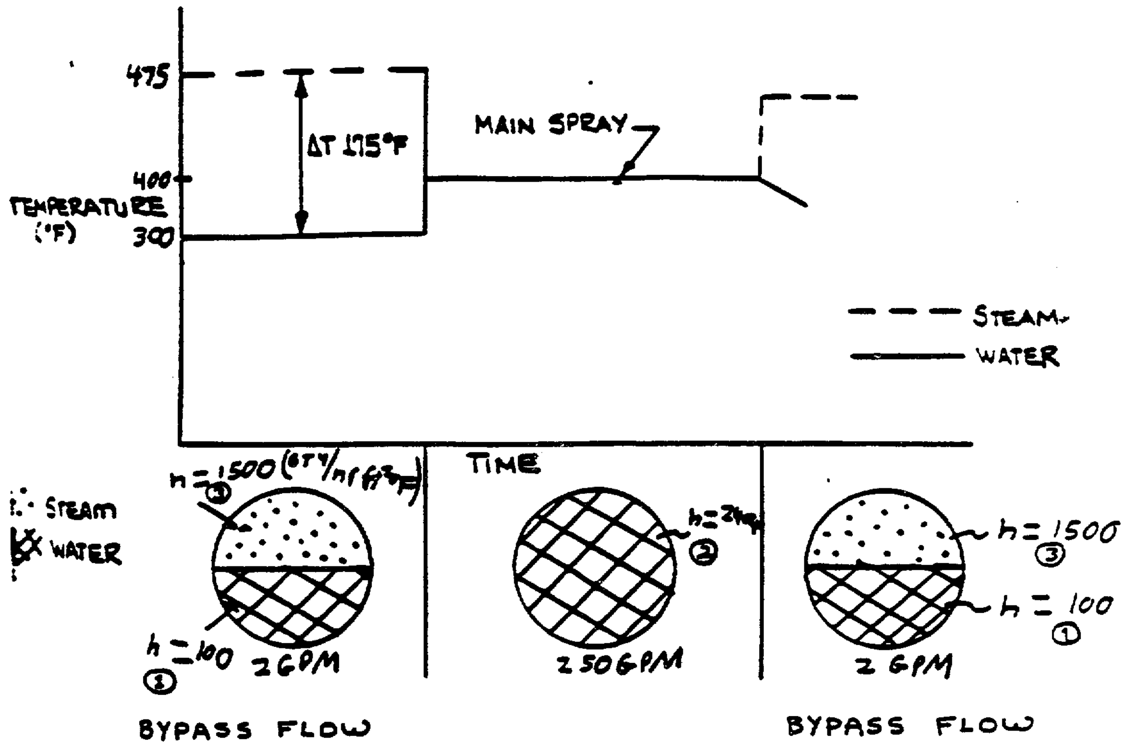
Prepared By RJG Date 3/23/00.

Reviewed By CT Date 3/23/00

Newly Specified (ABB/CE) Transient B-1 Stratified Flow $\Delta T = 175^{0}F$. (PRZR at $475^{0}F$.)

Sources: Pages E5 and E6 of Ref. O-3, and Figure 3.2-1 of Volume 1 of Ref. O-4

The Pressurizer is initially at 475°F with Main Spray Bypass Flow at 2 gpm and 300°F causing a steam/water stratified flow condition in the upper most horizontal spray header piping, while the vertically oriented nozzle and piping does not have stratified condition (Fig. 6, Sht. 1). When Main Spray Flow (250 gpm at 400°F) is initiated, the spray header instantaneously becomes filled with 400°F water and the metal reaches its equilibrium temperature. Main Spray is then secured and system parameters returned to the initial conditions. This transient can occur, 1) during plant heatups when less than four (4) RCP's are operating with Main Spray throttled for boron equalization and 2) after a RCP is secured during a cooldown and Main Spray is throttled and/or cycled for depressurization of the plant. This transient is categorized as a **normal condition with a total of 500** occurrences.



PLANT OPERATION CAUSING TRANSIENT

1) PLANT HEAT UP
   A) STARTING RCPs
   B) THROTTLING MAIN SPRAY FOR BORON EQUALIZATION

2) PLANT COOLDOWN
   A) SECURING RCPs
   B) THROTTLING AND/OR CYCLIC USE OF MAIN SPRAY FOR DEPRESSURIZATION

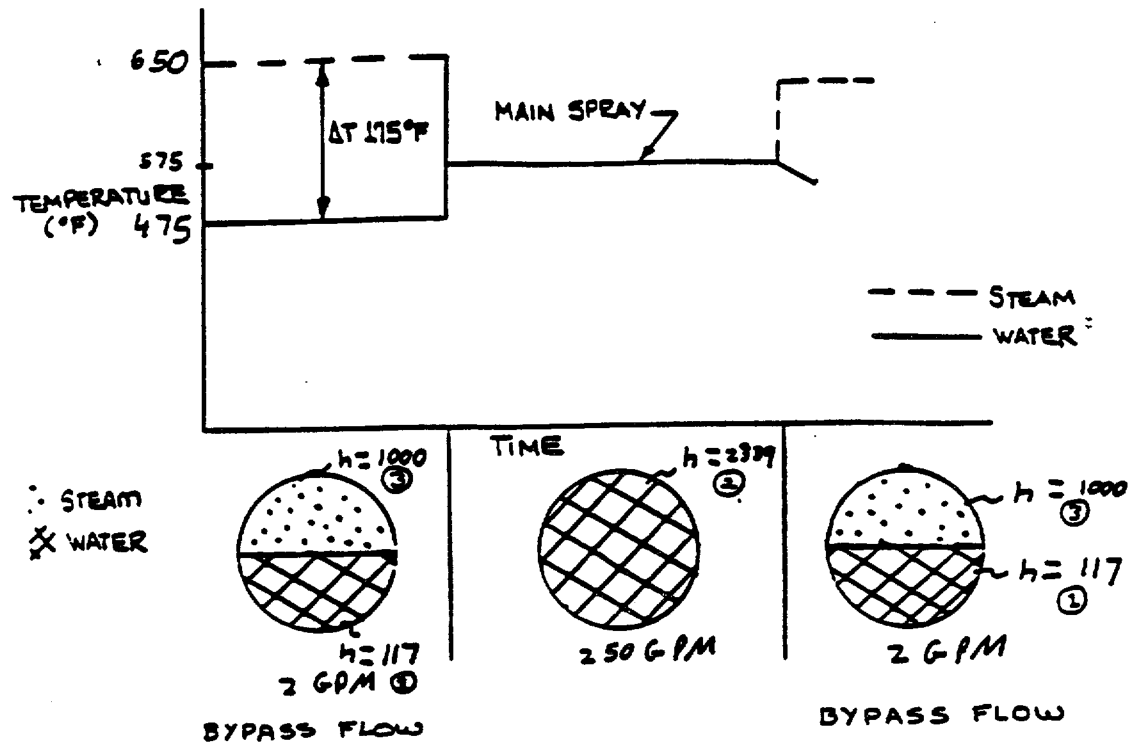
Prepared By RJG Date 3/23/00.

Reviewed By CY Date 3/23/00

Newly Specified (ABB/CE) Transient B-2 Stratified Flow $\Delta T = 175^{0}F$. (PRZR at $650^{0}F$.)

Sources: Page E6 of Ref. O-3, and Figure 3.2-2 of Volume 1 of Ref. O-4

The Pressurizer is initially at 650°F with Main Spray Bypass Flow at 2 gpm and 475°F causing a steam/water stratified flow condition in the upper most horizontal spray header piping, while the vertically oriented nozzle and piping does not have stratified condition (Fig. 6, Sht. 2). When Main Spray Flow (250 gpm at 575°F) is initiated, the spray header instantaneously becomes filled with 575°F water and the metal reaches its equilibrium temperature. Main Spray is then secured and system parameters returned to the initial conditions. This transient can occur, 1) during plant heatups when less than four (4) RCP's are operating with Main Spray throttled for boron equalization and 2) after a RCP is secured during a cooldown and Main Spray is throttled and/or cycled for depressurization of the plant. This transient is categorized as a **normal condition** with a total of **500** occurrences.



PLANT OPERATION CAUSING TRANSIENT

1) PLANT HEAT UP
   - A) STARTING RCPs
   - B) THROTTLING MAIN SPRAY FOR BORON EQUALIZATION

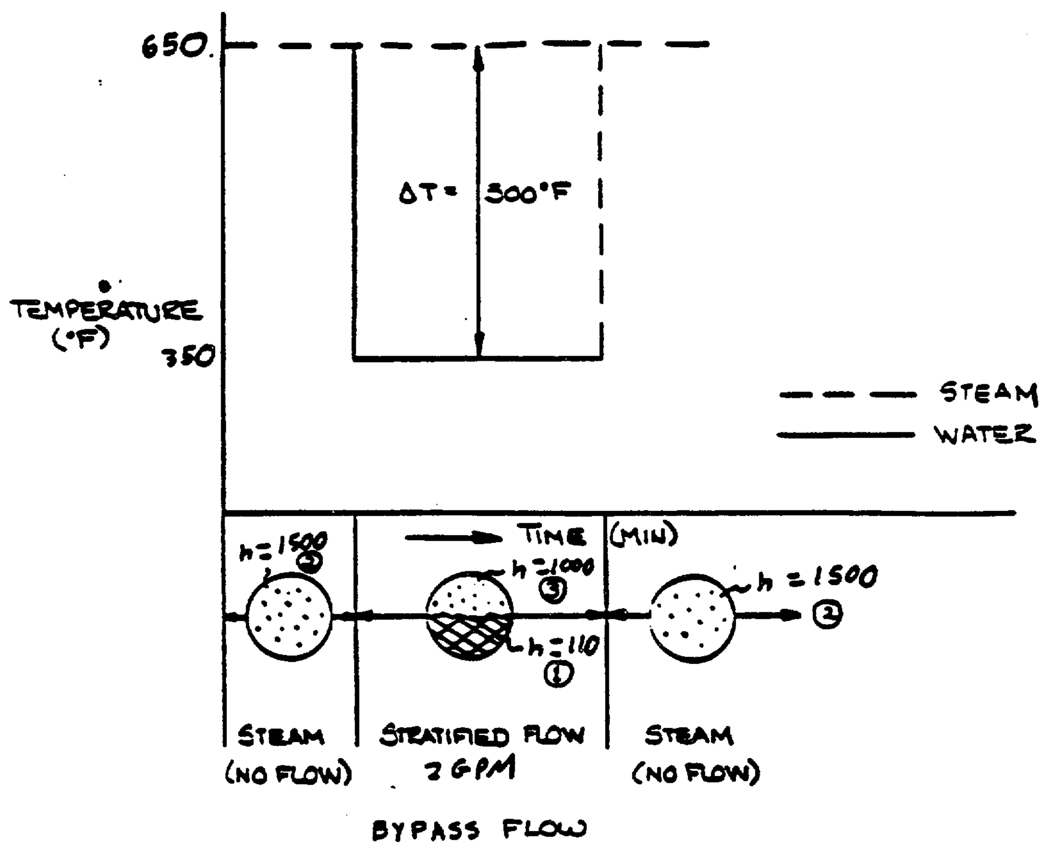
2) PLANT COOLDOWN
   - A) SECURING RCPs
   - B) THROTTLING AND/OR CYCLIC USE OF MAIN SPRAY FOR DEPRESSURIZATION

Prepared By RJG. Date 3/23/00.

Reviewed By CY Date 3/23/00

Newly Specified (ABB/CE) Transient B-3 Stratified Flow $\Delta T = 300^{0}F$.
Sources: Page E6 of Ref. O-3, and Figure 3.2-3 of Volume 1 of Ref. O-4

The Pressurizer is initially at 650°F with steam in the uppermost horizontal Main Spray Piping when Auxiliary Spray Flow at 350°F is initiated and throttled to 2 gpm causing a steam/water stratified flow condition as it enters the steam filled pipe, while the vertically oriented nozzle and piping does not have a stratified condition (Figure 6, Sht 3). After thermal equilibrium in the metal is reached, Auxiliary Spray Flow is then secured and the horizontal Main Spray piping instantaneously refills with steam (650°F). This spray line transient can occur when depressurizing the plant during cooldown and/or natural circulation and less than 4 RCPs are operating. This transient is categorized as a normal condition with a total of 250 occurrences.



PLANT OPERATIONS CAUSING TRANSIENT

1) PLANT COOLDOWN
   A) THROTTLING AUXILIARY SPRAY FOR DEPRESSURIZATION DURING NORMAL COOLDOWN AND/OR NATURAL CIRCULATION

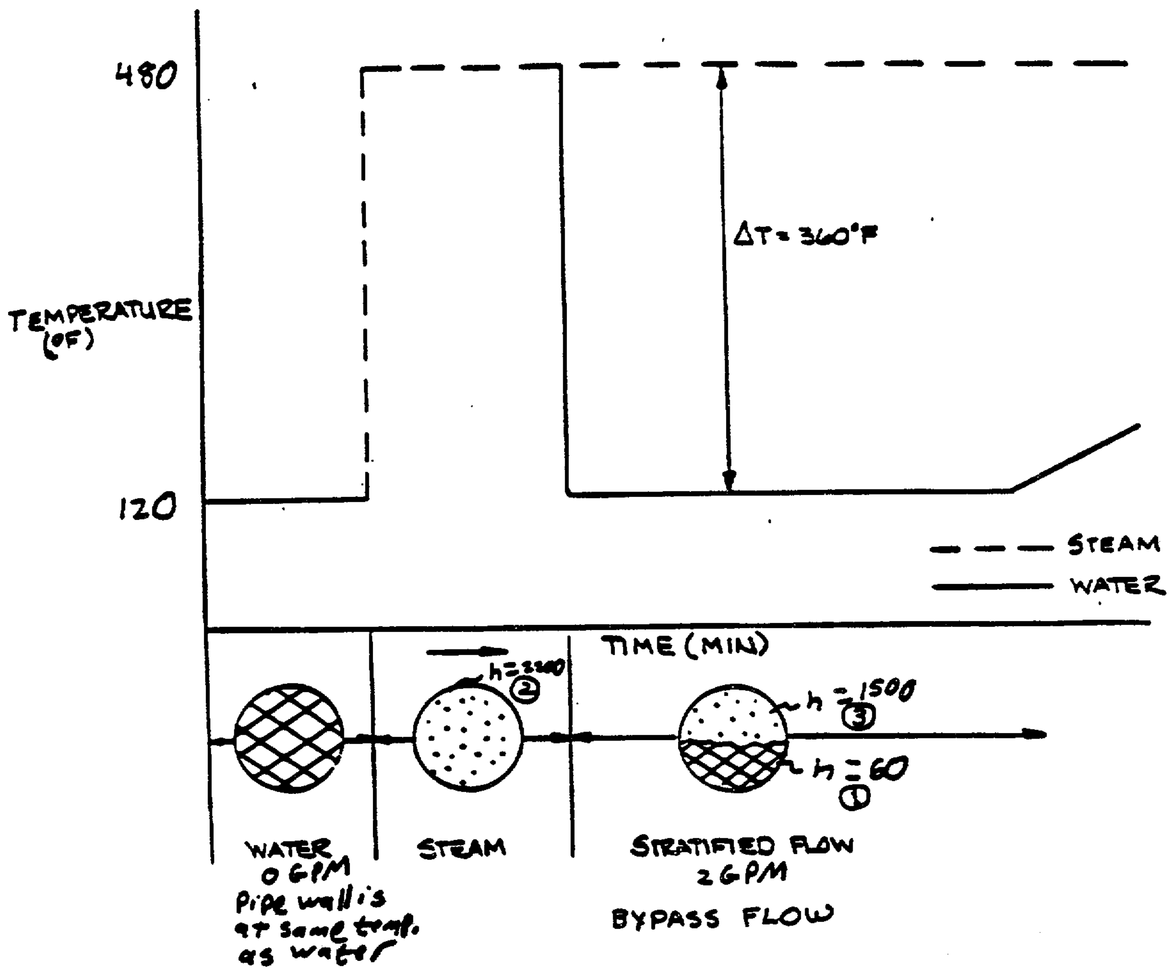
Prepared By RJG Date 3/23/00

Reviewed By CY Date 3/23/00

Newly Specified (ABB/CE) Transient <u>B-4</u> Stratified Flow $\Delta T = 360^0F$.

Sources: Pages E6 and E7 of Ref. O-3, and Figure 3.2-4 of Volume 1 of Ref. O-4

The Pressurizer and the uppermost horizontal Main Spray piping are initially filled with water (120°F) prior to the commencement of the steam bubble formation, the water in the uppermost horizontal Main Spray piping drains to the Pressurizer and fills with steam at 480°F and the metal reaches equilibrium. Subsequently, when a RCP is started, Main Spray bypass flow at 2 gpm and 120°F is initiated causing a steam/water stratified flow condition in the uppermost horizontal Main Spray piping, while the vertically oriented nozzle and piping does not have a stratified condition, (Figure 6, Sht. 4). This transient is categorized as a **normal condition** with a total of **80** occurrences.



PLANT OPERATIONS CAUSING TRANSIENT

1) PLANT HEAT UP
   A) STEAM BUBBLE FORMATION IN PRESSURIZER

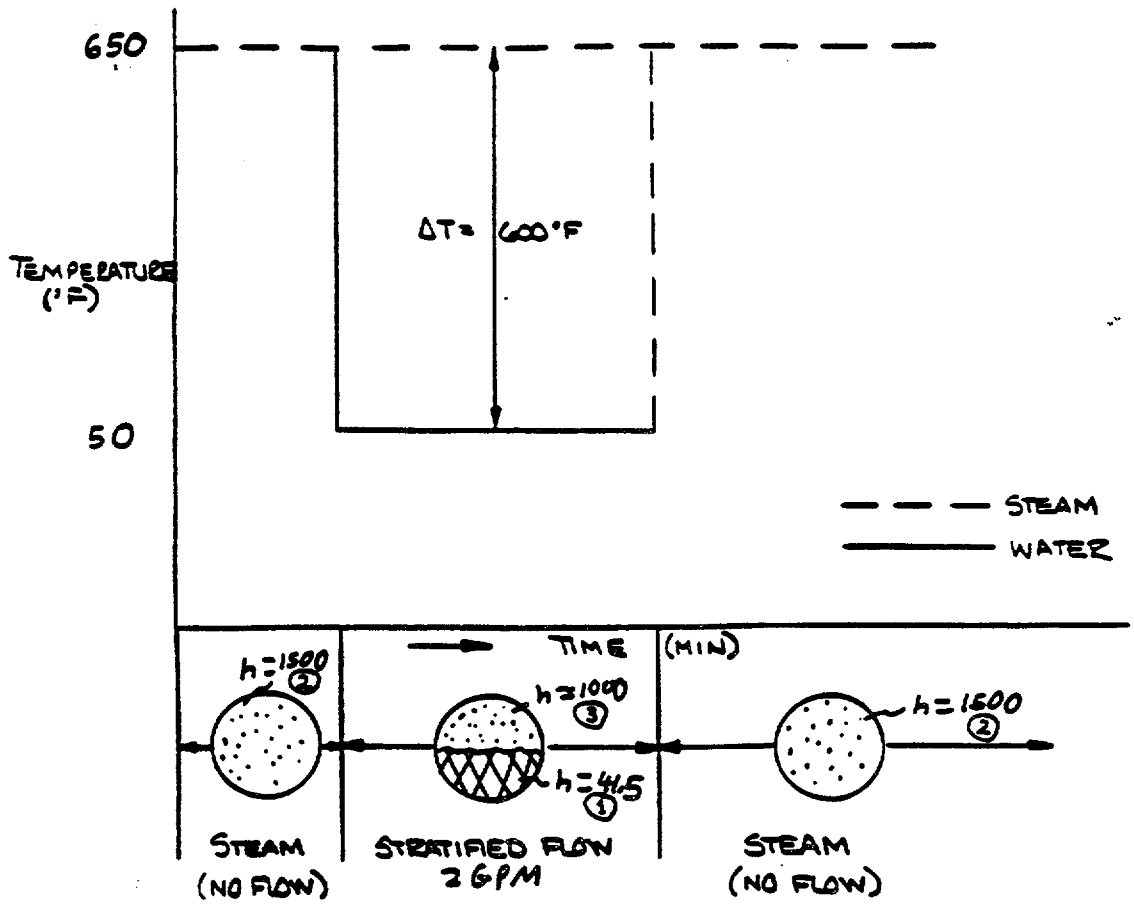
Prepared By RJG Date 3/23/00.

Reviewed By LY Date 3/23/00

Newly Specified (ABB/CE) Transient B-5 Stratified Flow $\Delta T = 600^{o}F$.

Sources: Page E7 of Ref. O-3, and Figure 3.2-5 of Volume 1 of Ref. O-4

The Pressurizer and the uppermost horizontal Main Spray piping are initially filled with steam, at 650°F with no Main Spray bypass flow as a result of all RCP's being secured. Auxiliary Spray flow at 50°F is initiated and throttled to 2 gpm and a water/steam stratified flow condition occurs in the uppermost horizontal Main Spray piping instantaneously as water enters the steam filled pipe, while the vertically oriented nozzle and piping does not have a stratified condition (Figure 6, Sht. 5). Auxiliary Spray flow is then secured after equilibrium in the metal is reached causing the horizontal Main Spray piping to refill with 650°F steam. This spray line transient occurs when depressurizing the plant during natural circulation. This transient is categorized as an upset condition with a total of 10 occurrences.



BYPASS FLOW

PLANT OPERATION CAUSING TRANSIENT

1) PLANT COOLDOWN
   A) THROTTLING OF AUXILIARY SPRAY DURING NATURAL CIRCULATION

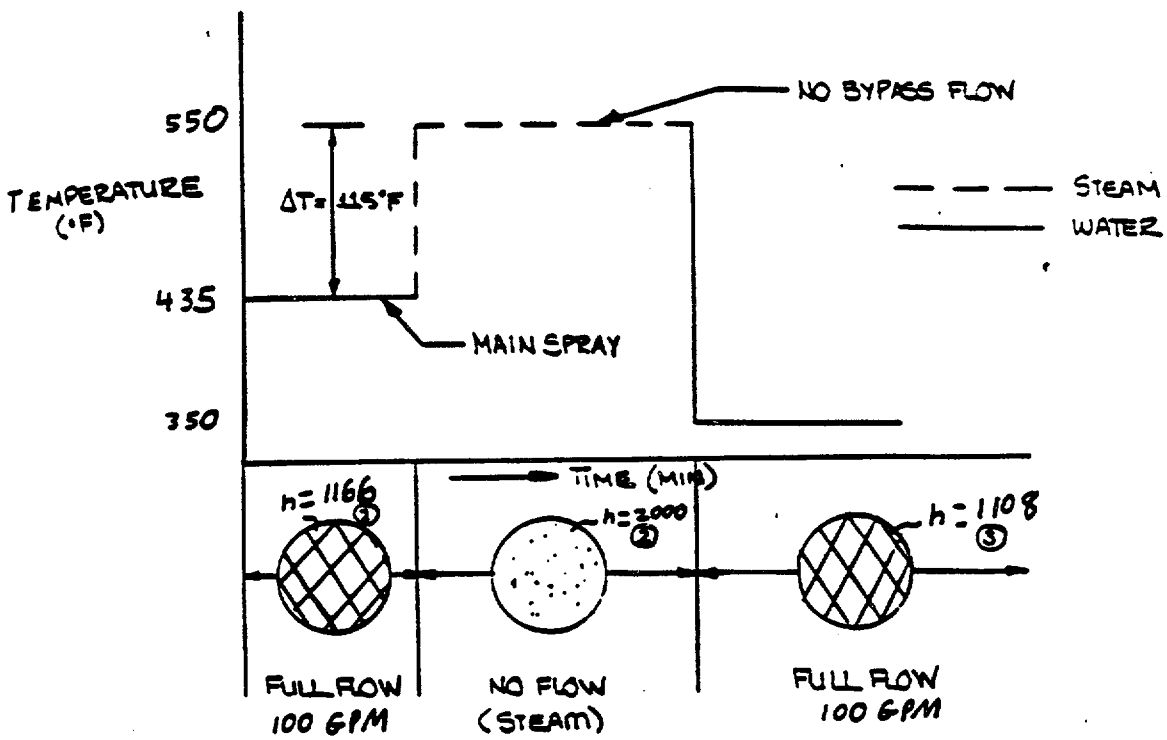
Prepared By RJG Date 3/23/00.

Reviewed By LY Date 3/23/00

Newly Specified (ABB/CE) Transient B-6 Full Flow $\Delta T = 115^0F$.

Sources: Page E7 of Ref. O-3, and Figure 3.2-6 of Volume 1 of Ref. O-4

The Pressurizer is initially at 550°F with the Main Spray aligned at 100 gpm and 435°F to depressurize the plant during cooldown (Figure 6, Sht. 6). When Main Spray is secured to limit the rate of depressurization, the water in the uppermost horizontal Main Spray piping drains back to the Pressurizer and fills with steam at 550°F. This is due to insufficient hydraulic driving head to provide Main Spray bypass flow as a result of less than four (4) RCP's operating. As cooldown of the plant continues, Main Spray is reinitiated at 350°F to continue plant depressurization which causes the 550°F steam to be replaced by 350°F water. This is categorized as a **normal condition** with a total of **500 occurrences.**



PLANT OPERATION CAUSING TRANSIENT

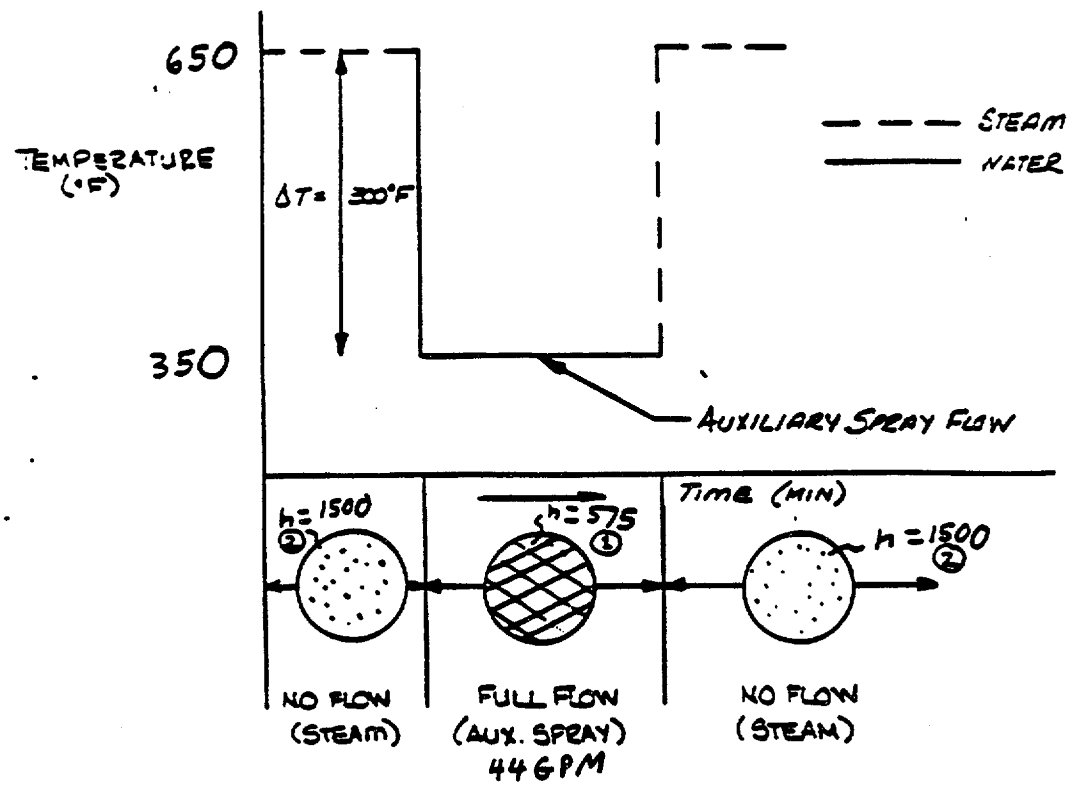
1) PLANT COOLDOWN
   A) SECURING RCPs
   B) CYCLIC USE AT MAINSPRAY FOR DEPRESSURIZATION

Prepared By RJG Date 3/23/00.

Reviewed By CY Date 3/23/00

Newly Specified (ABB/CE) Transient B-7 Full Flow $\Delta T = 300^{\circ}F$.
Sources: Page E7 of Ref. O-3, and Figure 3.2-7 of Volume 1 of Ref. O-4

The Pressurizer and uppermost horizontal section of Main Spray piping are initially filled with 650°F steam with no Main Spray bypass flow (Figure 6, Sht. 7). When Auxiliary Spray is initiated at 44 gpm and 350°F, the 650°F steam is displaced in the uppermost horizontal section of Main Spray piping. Once the metal has reached equilibrium, Auxiliary Spray is secured and the uppermost horizontal section of Main Spray piping refills with 650°F steam. This transient can occur during plant cooldown when there are insufficient RCP's operating to produce main Spray Bypass flow. This transient is categorized as a normal condition with a total of 250 occurrences.



PLANT OPERATION CAUSING TRANSIENT

1) PLANT COOLDOWN
   A) CYCLIC USE OF AUXILIARY SPRAY FOR DEPRESSURIZATION DURING NORMAL COOLDOWN AND/OR NATURAL CIRCULATION

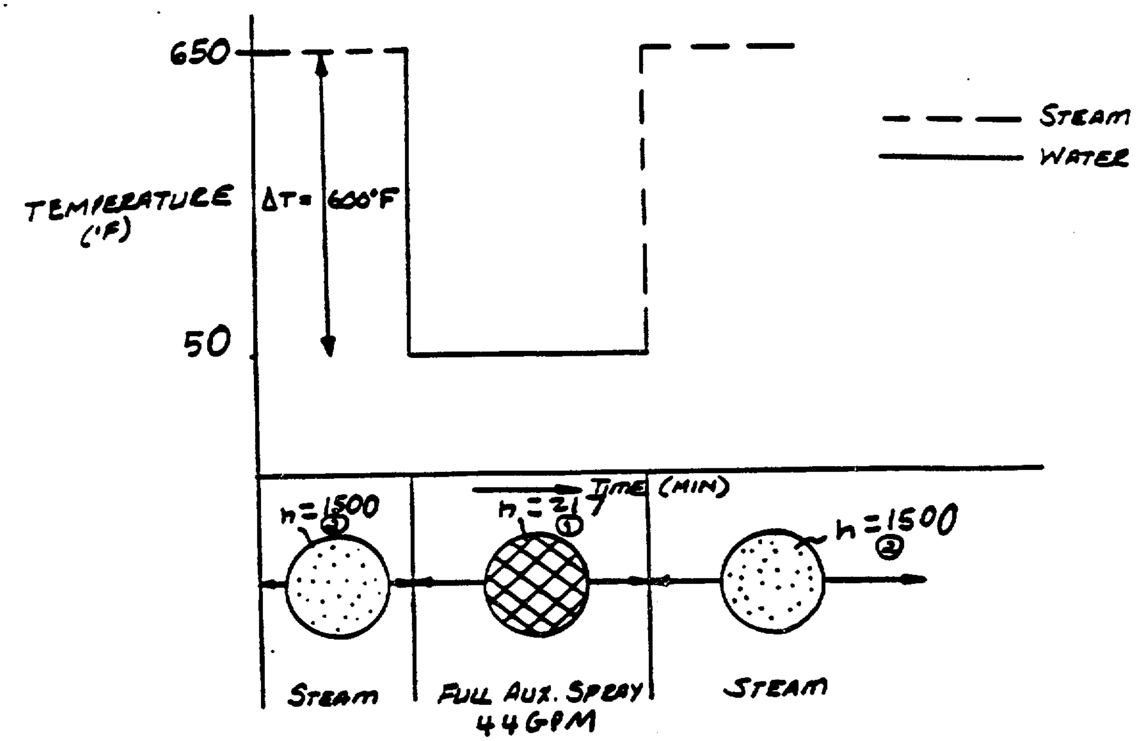
Prepared By RJG Date 3/23/00.

Reviewed By CY Date 3/23/00

Newly Specified (ABB/CE) Transient B-8 Full Flow $\Delta T = 600^{0}F$.

Sources: Pages E7 and E8 of Ref. O-3, and Figure 3.2-8 of Volume 1 of Ref. O-4

The Pressurizer and uppermost horizontal section of Main Spray piping are initially filled with 650°F steam with no Main Spray bypass flow (Figure 6, Sht. 8). When Auxiliary Spray is initiated at 44 gpm and 50°F, the 650°F steam is displaced in the uppermost horizontal section of Main Spray piping. Once the metal has reached thermal equilibrium, Auxiliary Spray is secured and the uppermost horizontal section of Main Spray piping refills with 650°F steam. This transient can occur during plant cooldown when there are insufficient RCP's operating to produce Main Spray bypass flow or when depressurizing the plant during natural circulation. This transient is categorized as a normal condition with a total of 10 occurrences.



PLANT OPERATIONS CAUSING TRANSIENT

1) PLANT COOLDOWN
   A) CYCLIC USE OF AUXILIARY SPRAY FOR DEPRESSURIZATION DURING NATURAL CIRCULATION

Prepared By RJG Date 3/23/00.

Reviewed By LY Date 3/23/00

Brief description of the Transients (page 1 of 2)

[B.1 through B.5]

B.1: Less than 4 RCPs operating during either heat-up or cooldown (500 occurrences)

PRZR at 475 degrees F., Main Spray Bypass Flow at 300 degrees F. (2 gpm.), causing strat. in the uppermost horiz. section of the pipe.
Main Spray is initiated (250 gpm at 400 degrees F.)
Then, main spray is secured, returning to the initial conditions.

B.2: Less than 4 RCPs operating during either heat-up or cooldown (500 occurrences)

PRZR at 650 degrees F., Main Spray Bypass Flow at 475 degrees F. (2 gpm.), causing strat. in the uppermost horiz. section of the pipe.
Main Spray is initiated (250 gpm at 575 degrees F.)
Then, main spray is secured, returning to the initial conditions.

B.3: Less than 4 RCPs operating during plant cooldown (depressurization) (250 occurrences)

PRZR and uppermost horiz. spray piping at 650 degrees F. (steam). No main Spray bypass flow.
Aux. Spray is initiated at 350 degrees F. (2 gpm.)
The water flows into PRZR, causing a steam/water stratified condition in the uppermost horiz. section of the pipe.
The metal reaches equilibrium.
Aux. Spray is secured. The uppermost horiz. spray piping refills with 650 degree F. steam.

B.4: Heat-up / Prior to Start of the steam bubble formation (80 occurrences)

PRZR and uppermost horiz. spray piping at 120 degrees F. (water).
This water drains into PRZR, and is replaced by 480 degree F. steam.
RCP is started, and a Main Spray Bypass flow is initiated (2 gpm at 120 degrees F.), causing thermal strat. in the uppermost horiz. section of the pipe.

B.5: Depressurization of the Plant during Natural Circulation Cooldown (10 occurrences)

PRZR and uppermost horiz. spray piping at 650 degrees F. (steam). No main Spray bypass flow.
Aux. Spray is initiated at 50 degrees F. (2 gpm.)
The water flows into PRZR, and the 650 degree steam is displaced from the uppermost horiz. spray piping.
The metal reaches equilibrium.
Aux. Spray is secured.
The uppermost horiz. spray piping refills with 650 degree F. steam.

[this Transient B.5 has been reclassified as an Emergency Condition; see further in text in this Sub-section O-3]

Prepared By RJG Date 3/23/00.

Reviewed By LT Date 3/23/00

Brief description of the Transients (page 2 of 2)

[B.6 through B.8]

B.6: Less than 4 RCPs operating leading to insufficient hydraulic driving head to provide Main Spray bypass flow (500 occurrences)

PRZR at 550 degrees F., Main Spray at 435 degrees F. (100 gpm.)
Main Spray is secured (to limit the rate of depressurization)
The water flows into PRZR, and the uppermost horiz. spray piping fills with steam at 550 degrees F.
Then, main spray is reinitiated at 350 degrees F., to continue plant depressurization.
The 550 degree F. steam is replaced by the 350 degree F. water.

B.7: Insufficient RCPs operating to produce Main Spray bypass flow (250 occurrences)

PRZR and uppermost horiz. spray piping at 650 degrees F. (steam). No main Spray bypass flow.
Aux. Spray is initiated at 350 degrees F. (44 gpm.)
The water flows into PRZR, and the 650 degree steam is displaced from the uppermost horiz. spray piping.
The metal reaches equilibrium.
Aux. Spray is secured.
The uppermost horiz. spray piping refills with 650 degree F. steam.

The two transients B.6 and B.7 are "Normal Condition" transients, and both occur during Cooldown.

B.8: Insufficient RCPs operating to produce Main Spray bypass flow, or Natural Circulation Cooldown (10 occurrences)

Same as B.7 above, with the only difference that the Aux. Spray water is at 50 degrees F., instead of 350 degrees F. (same number for the flow rate : 44 gpm.) [occurs during Cooldown]

[this Transient B.8 has been reclassified as an Emergency Condition; see further in text in this Sub-section O-3]

Discussion

The purpose of this Discussion is to verify whether the eight new Transients B-1 through B-8 are covered by other analyzed Transients for the Main Spray Line below the uppermost horizontal portion of the Line, and for the Auxiliary Spray Line.

1.) Main Spray Activation Transients (B-1, B-2, B-4 and B-6)

B-1, 500 occurrences, during heat-up or cooldown :
2 gpm 300° F. Main Spray (thermal Strat.) is changed to a 250 gpm 400° F. Main Spray.
→ Covered by 2 gpm 450° F. Main Spray (Bypass), changing to 375 gpm 555° F. Main Spray

B-2, 500 occurrences, during heat-up or cooldown :
2 gpm 475° F. Main Spray (thermal Strat.) is changed to a 250 gpm 575° F. Main Spray.
→ Covered by 2 gpm 450° F. Main Spray (Bypass), changing to 375 gpm 555° F. Main Spray

B-4, 80 occurrences:
The riser stays at 120° F. for the entire time of this Transient. (no transient per-say for the riser; no DT1 and DT2 values)

B-6, 500 occurrences :
100 gpm 435° F. Main Spray is suddenly secured (0 gpm Main Spray).
→ Covered by 375 gpm 555° F. Main Spray, suddenly secured with temperature dropping slowly to 450° F.

The only difference here is that a 100 gpm 350° F. main spray is reinitiated later on, but it can be easily considered that the temperature in the riser has dropped into a range between 350° F. and 400° F., before the 350° F. Main Spray reinitiation occurs.

Conclusion: the four Main Spray Activation Transients B-1, B-2, B-4 and B-6 are really "modified versions" of Transients previously analyzed.

2.) Auxiliary Spray Activation Transients (B-3, B-5, B-7 and B-8)

It has been verified that the four Auxiliary Spray Activation Transients are not "modified versions" of Transients previously analyzed. Therefore, these Transients will have to be re-analyzed in this Attachment O. Note, however, here that the Aux. Spray Activation Transients B-5 and B-8 are eliminated from the Fatigue/Stress Analyses due to their reclassification as an "Emergency" Condition (see next page).

Conclusion: Transients B-5 and B-8 do not need to be considered in the revised Fatigue/Stress analyses of this Attachment O (see reclassification on the next page). However, the other two Aux. Spray Activation Transients B-3 and B-7 will have to be considered for temperature differences in the Auxiliary Spray Line itself and in the Main Spray Riser between the top vertical elbow of the Riser and the 3" * 3" * 3" Tee located, on the Main Spray Line, just below the 4" by 4" by 2" Aux. Spray Tee.

Prepared By RJG Date 3/23/00.

Reviewed By LY Date 3/23/00

Reclassification of the Auxiliary Spray Activation Transients B-5 and B-8

NB-3113(b) of the 1980 Edition of the ASME Code (Ref. O-6) states that service conditions can be reclassified as "Emergency" as long as they do not cause more than 25 stress cycles with an alternating stress value (Sa) greater than that for 10^6 cycles on the applicable Fatigue Design Curve. As Transient B-5 and Transient B-8 cause only one stress cycle per Transient, as the number of occurrences for Transient B-5 is 10, and as the number of occurrences for Transient B-8 is 10, these Transients B-5 and B-8 (total of 20 cycles) are here being reclassified to an "Emergency Level" (also referred to as a "Level C condition").

NB-3224.4 of the 1980 Edition of the ASME-Code (Ref. O-6) refers to the fact that, for Transients at the "Emergency Level", the requirements of NB-3222.2 (Primary Plus Secondary Stress Intensity), NB-3222.4 (Analysis for Cyclic Operation), NB-3222.5 (Thermal Stress Ratchet) and NB-3227.3 (Progressive Distortion of Nonintegral Connections) do not need to be satisfied. Also, Figure NB-3224-1 (Stress Categories and Stress Limits for "Level C") mentions clearly that an Evaluation is not required for any Secondary (Q) or Peak (F) type of stress. Therefore, "Emergency Level" Transients do not need to be included in the Fatigue/Stress Analysis of the Component (Main Spray Line / Auxiliary Spray Line Piping System).

The Reaction Loads from the Emergency Transients B-5 and B-8 will be listed in Sub-section O-20, together with the Reaction Loads from the other new (B-type) Transients.

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