Appendix 3B Leak-Before-Break Evaluation of the AP1000 Piping

General Design Criterion 4 requires that structures, systems, and components important to safety be designed to accommodate the effects of conditions associated with normal operation, anticipated transients, and postulated accident conditions. However, the dynamic effects associated with pipe rupture may be excluded when analysis demonstrates that the probability of fluid system pipe rupture is extremely low. Dynamic effects are not considered for those segments of piping that are shown mechanistically, with a large margin, not to be susceptible to a pipe rupture.

The dynamic effects associated with pipe rupture include effects such as pipe break reaction loads, jets and jet impingement, subcompartment pressurization loads, and transient pipe rupture depressurization loads on other components.

The use of mechanistic pipe break to eliminate evaluation of dynamic effects of pipe rupture includes material selection, inspection, leak detection, and analysis. Subsection 3.6.3 outlines considerations relative to material selection, inspections, and leak detection. Subsection 5.2.5 describes the leak detection system inside containment. This appendix describes the analysis methods used to support the application of mechanistic pipe break to high-energy piping in the AP1000.

The analysis and criteria to eliminate dynamic effects of pipe breaks are encompassed in a methodology called leak-before-break (LBB). This methodology has been validated by theoretical investigations and test demonstrations sponsored by the industry and the NRC.

The primary regulatory documents for leak-before-break analyses are General Design Criterion No. 4 (GDC-4), Draft Standard Review Plan 3.6.3 (SRP 3.6.3) (Reference 1), and NUREG-1061, Volume 3 (Reference 2). Although SRP 3.6.3 has been issued only as a draft, its provisions are followed as guidelines to leak-before-break analyses.

Leak-before-break methodology has been applied to the reactor coolant loop and high-energy auxiliary line piping in operating nuclear power plants. The leak-before-break analysis used to support the piping design of the AP1000 is an application of the same methodology used in leak-before-beak evaluations previously accepted by the NRC.

In the AP1000, leak-before-break evaluations are performed for the reactor coolant loop, the surge line, selected other branch lines containing reactor coolant down to and including 6-inch diameter nominal pipe size, and portions of the main steam line. Those lines not qualified to the leak-before-break criteria are evaluated using the pipe rupture protection criteria outlined in subsections 3.6.1 and 3.6.2.

This appendix provides a leak-before-break analysis for the applicable piping systems. Table 3B-1 provides a list of AP1000 leak-before-break piping systems.

3B.1 Leak-before-Break Criteria for AP1000 Piping

The methodology used for leak-before-break analysis is consistent with that set forth in GDC-4, SRP 3.6.3 (Reference 1) and NUREG-1061, Volume 3 (Reference 2). The steps are:

- Evaluate potential failure mechanisms
- Perform bounding analysis

3B.2 Potential Failure Mechanisms for AP1000 Piping

In high-energy piping, there are material degradation mechanisms that could adversely affect the integrity of the system as well as its suitability for leak-before-break analysis. The following lists potential degradation (or "failure") mechanisms:

- Erosion-corrosion induced wall thinning
- Stress corrosion cracking (SCC)
- Water hammer
- Fatigue
- Thermal aging
- Thermal stratification
- Other mechanisms

The stainless steel piping is fabricated of SA312TP316LN or SA312TP304L material. The type 304L material is used in the accumulator discharge lines. The main steam piping is fabricated of SA335 Grade P11. The welds are made by the gas tungsten arc welding (GTAW) method.

The various degradation mechanisms are discussed in the following subsections.

3B.2.1 Erosion-Corrosion Induced Wall Thinning

Primary Loop Piping

Wall thinning by erosion and erosion-corrosion effects does not occur in the primary loop piping because Series 300 austenitic stainless steel material is highly resistant to these effects. The coolant velocity in the AP1000 primary loop is about 76 feet per second. This flow velocity is not expected to create erosion-corrosion effects since stainless steels are considered to be virtually immune (Reference 3). A review of erosion-corrosion in nuclear power systems (Reference 4) reported that "stainless steels are increasingly being used due to their excellent resistance to erosion-corrosion, even at high water velocities, 40 m/s (131 ft/sec)." The bend radii in the AP1000 hot and cold legs are greater than the bend radii used in the crossover legs of operating plants. There is no record of erosion-corrosion induced wall thinning in the primary loops of operating plants.

Auxiliary Stainless Steel Piping

Wall thinning by erosion-corrosion effects does not occur in the auxiliary stainless steel piping because Series 300 austenitic stainless materials are highly resistant to these effects. The coolant velocity in these systems is lower than in comparable systems in operating Westinghouse-designed pressurized water reactors. There is no record of erosion-corrosion induced wall thinning in the stainless steel piping of operating plants.

Main Steam Line

Main steam lines in the AP1000 are fabricated from SA335 Grade P11 Alloy steel. Erosion-corrosion induced wall thinning is not expected in the main steam line. Extensive work has been done investigating erosion-corrosion in carbon steel pipes. The main steam line has low susceptibility to erosion due to the pipe material composition, which has sufficient levels of chromium to preclude erosion-corrosion material loss. Susceptibility is also low due to the relatively high operating temperature and the high quality steam in the main steam line.

Based on the above discussion, erosion-corrosion induced wall thinning does not have an adverse effect on the integrity of the AP1000 leak-before-break piping systems.

3B.2.2 Stress Corrosion Cracking

Stress corrosion cracking is not expected to occur in the AP1000 piping systems because the three conditions necessary for stress corrosion cracking to take place are not present. If any of these three conditions is not present, stress corrosion cracking will not take place. The three conditions are:

- There must be a corrosive environment.
- The material itself must be susceptible.
- Tensile stresses must be present in the material.

Primary Loop Piping

During plant operation, the reactor coolant water chemistry is monitored and maintained within specific limits (see subsection 5.2.3 for a discussion of reactor coolant chemistry). Contaminant concentrations are kept below the thresholds known to be conducive to stress corrosion cracking. The major water chemistry control standards are included in the plant operating procedures as a condition for plant operation.

The key to avoidance of a corrosive environment is control of oxygen. During normal power operation, oxygen concentration in the reactor coolant system is controlled to extremely low levels by controlling charging flow chemistry and maintaining a hydrogen overpressure in the reactor coolant at specified concentrations. Halogen concentration is controlled by maintaining concentrations of chlorides and fluorides within the specified limits. During plant operations, the likelihood of stress corrosion cracking in the primary loop piping systems is very low.

The elements of a water environment known to increase the susceptibility of austenitic stainless steel to stress corrosion are oxygen, fluorides, chlorides, hydroxides, hydrogen peroxide, and reduced forms of sulfur (for example, sulfides, sulfites, and thionates). Pipe cleaning standards prior to operation and careful water chemistry control during plant operation are applied to prevent the occurrence of a corrosive environment. Before being placed in service the piping is cleaned. During flushes and preoperational testing, water chemistry is controlled according to written specifications. Standards on chlorides, fluorides, conductivity, and pH are included in the guidelines for water for cleaning the piping.

Series 300 stainless steel materials have been chosen for the AP1000 due to their proven operating experience. These materials have operated in low-oxygen or no-oxygen environments with no incidents for a number of years. The requirements of Regulatory Guide 1.44 will be used to maintain the experiences of the PWR applications for the use of Series 300 stainless steel materials.

Design tensile stresses in the reactor coolant loop are within the ASME Code, Section III allowables. Residual tensile stresses are expected in the welds and such stresses are not considered when designing by the ASME Code, Section III because these stresses are self-equilibrating and do not affect the failure loads. The residual stresses should not be more severe than for the operating Westinghouse pressurized water reactor plants (which have not experienced stress corrosion cracking in the primary loop).

The material used for buttering nozzles at the stainless-to-carbon steel safe ends is a high nickel alloy. The nickel-chromium-iron alloy selected and qualified for this application is not susceptible to primary water stress corrosion cracking.

Auxiliary Stainless Steel Piping

The discussion above regarding the necessary conditions for primary loop piping stress corrosion cracking is also applicable to the other stainless steel piping of the primary system.

Series 300 stainless steel materials have been chosen for the AP1000 due to their proven operating experience. These materials have operated in low-oxygen or no-oxygen environments with no incidents for a number of years. The requirements of Regulatory Guide 1.44 will be used to maintain the experiences of the PWR applications for the use of Series 300 stainless steel materials.

Design tensile stresses in the other stainless steel piping are within the ASME Code, Section III allowables. Residual tensile stresses are expected in the welds; however, the residual stresses should not be more severe than for the operating Westinghouse pressurized water reactor plants (which have not experienced stress corrosion cracking in the auxiliary stainless steel piping).

Main Steam Line

The main steam piping is constructed from ferritic steel. Stress corrosion cracking in ferritic steels commonly result from a caustic environment. A source of a caustic environment in the main steam piping would be moisture carryover from the steam generator. However, the secondary side water treatment utilizes all volatile treatment. All volatile treatment effectively precludes causticity in the steam generator bulk liquid environment. For some operating plants prior to implementing all volatile treatment, the phosphate water treatment caused a caustic chemical imbalance resulting in stress corrosion cracking of steam generator tubing. Under all volatile treatment water treatment conditions, there is no instance of caustic stress corrosion cracking on the ferritic steam lines indicating no significant caustic carryover. The operating secondary side chemistry precludes stress corrosion cracking on the ferritic main steam line.

Based on the above discussion, stress corrosion cracking does not have an adverse effect on the integrity of AP1000 leak-before-break piping systems.

3B.2.3 Water Hammer

Primary Loop Piping

The reactor coolant loop is designed to operate at a pressure greater than the saturation pressure of the coolant, thus precluding the voiding conditions necessary for water hammer to occur. The reactor coolant primary system is designed for Level A, B, C, and D (normal, upset, emergency, and faulted) service condition transients. The design requirements are conservative relative to both the number of transients and their severity. Relief valve actuation and the associated hydraulic transients following valve opening have been considered in the system design. Other valve and pump actuations cause relatively slow transients with no significant effect on the system dynamic loads.

To provide dynamic system stability, reactor coolant parameters are controlled. Temperature during normal operation is maintained within a narrow range by control rod positioning. Pressure is controlled within a narrow range for steady-state conditions by pressurizer heaters and pressurizer spray. The flow characteristics of the system remain constant during a fuel cycle. The operating transients of the reactor coolant system primary loop piping are such that significant water hammer loads are not expected to occur.

Auxiliary Stainless Steel Piping

The passive core cooling system and automatic depressurization system are designed to minimize the potential for water hammer induced dynamic loads. Design features include:

- Continuously sloping core makeup tank and passive residual heat exchanger inlet lines to eliminate local high points

- Inlet diffusers in the core makeup tanks to preclude adverse steam and water interactions

- Vacuum breakers in the discharge lines of the automatic depressurization valves connected to the pressurizer

The AP1000 pressurizer spray control valve is similar to what is used in the operating plants. There is no history of water hammer caused by the spray control valve.

The normal residual heat removal system isolation valves are slow closing valves, identical to operating plants, and therefore would not be a source of water hammer.

These features minimize the potential of water hammer in the auxiliary stainless steel piping system.

Main Steam Line

The steam lines are not subject to water hammer by the nature of the fluid transported. The following system design provisions address concerns regarding steam hammer within the main steam line and identify the significant dynamic loads included in the main steam piping design.

- Design features that prevent water slug formations are included in the system design and layout. In the main steam system, these include the use of drain pots and the proper sloping of lines.

- The operating and maintenance procedures that protect against a potential occurrence of steam hammer include system operating procedures that provide for slowly heating up (to avoid condensate formation from hotter steam on colder surfaces), operating procedures that caution against fast closing of the main steam isolation valves except when necessary, and operating and maintenance procedures that emphasize proper draining.

- The stress analyses for the safety-related portion of the main steam system piping and components include the dynamic loads from rapid valve actuations, including actuation of the main steam isolation valves and the safety valves.

Based on the above discussion, water hammer does not have an adverse effect on the integrity of AP1000 leak-before-break piping systems.

3B.2.4 Fatigue

Low-Cycle Fatigue

Low-cycle fatigue due to normal operation and anticipated transients is accounted for in the design of the piping system. The Class 1 piping systems comply with the fatigue usage requirements of the ASME Code, Section III. The Class 2 and 3 piping systems comply with the stress range reduction factors of the ASME Code, Section III.

Due to the nature of operating parameters, main steam line piping (Class 2) and the Class 3 portion of the accumulator piping, are not subjected to any significant transients to cause low-cycle fatigue.

Based on the above discussion, low-cycle fatigue is not a concern of AP1000 leak-before-break piping systems.

High-Cycle Fatigue

High-cycle fatigue loads in the system result primarily from pump vibrations. The steam generator is designed so that flow-induced vibrations in the tubes are avoided (see subsection 5.4.2). The loads from reactor coolant pump vibrations are minimized by criteria for pump shaft vibrations during hot functional testing and operation. During operation, an alarm signals when the reactor coolant pump vibration is greater than the limits.

With these precautions taken, the likelihood of leakage due to fatigue in piping systems evaluated for leak-before-break is very small.

3B.2.5 Thermal Aging

Stainless Steel Piping

Piping used in the reactor coolant loop and other auxiliary lines are wrought stainless steel materials, rather than cast materials, so that thermal aging concerns are not expected for the AP1000 piping and fittings. The welds used in the assembly of the AP1000 are gas tungsten arc welds (GTAW). These welds are essentially as resistant to the effects of thermal aging as the base metal materials. This is due to the typically low ferrite contact in welds which results in minimal impact from thermal aging. Based on this information, thermal aging of weld materials and piping used in the AP1000 is not an issue.

Main Steam Lines

The main steam piping system does not have cast materials. The welding process used on these lines is also gas tungsten arc weld (GTAW).

There are no thermal aging concerns for the carbon steel piping of the main steam line and the alloy steel of the main feedwater piping.

The material used for the main steam piping system is not susceptible to dynamic strain aging effects.

3B.2.6 Thermal Stratification

Leak-before-break analyses include consideration of the loads and stresses due to thermal stratification.

Thermal stratification occurs only in a pipe that has a susceptible geometry and low flow velocities. A temperature difference between the flowing fluid and stagnant fluid is also a prerequisite.

The design of piping and component nozzles in the AP1000 includes provisions to minimize the potential for and the effects of thermal stratification, cycling, and striping, pursuant to actions requested in several NRC bulletins, as discussed below.

Primary Loop Piping

Thermal stratification in the reactor coolant loops resulting from actuation of passive safety features is evaluated as a design transient. Stratification effects due to both Level B and Level D service conditions are considered. The criteria used in the evaluation of the stress in the loop piping due to stratification is the same as that applicable for other Level B and Level D service conditions.

Auxiliary Stainless Steel Piping

Pursuant to the actions requested in NRC Bulletin 88-11, the pressurizer surge line is analyzed to demonstrate that the applicable requirements of the ASME Code, Section III are met. This analysis includes consideration of plant operation, thermal stratification, and thermal striping using temperature distributions and transients developed from experience on existing plant monitoring programs.

Pursuant to the actions requested in NRC Bulletin 88-08 (cracking in piping connected to reactor coolant systems due to isolation valve leakage), a systems review of the AP1000 piping was performed in accordance with the criteria provided in subsection 3.9.3.1.2.

The unisolable sections of the following lines which are evaluated for leak-before-break have been reviewed and are not susceptible to adverse stresses as described in NRC Bulletin 88-08:

Passive residual heat removal (PRHR) line from the hot leg, through the passive residual heat removal heat exchanger, and to the steam generator channel head
The potential for leakage through the isolation valves is not a concern for the piping extending from the reactor coolant system hot leg connection to the passive residual heat removal heat exchanger inlet, since hot leakage from the reactor coolant system would be entering a hot section of piping. Leakage exiting the passive residual heat removal heat exchanger would not be a concern since the cooled leakage would be entering a cold section of piping. This leakage would then heat up in the piping directly below the steam generator. Any amount of leakage is expected to be small, since the pressure differential across the isolation valves is about 50 psi (the difference between the hot leg and reactor coolant pump suction pressures). Activation of the passive residual heat removal system following a plant scram is not a concern, since stratification will not occur due to the high flow velocity in the passive residual heat removal return flow line.

Automatic depressurization stage 4 lines from the hot legs to the stage 4 depressurization valves
Leakage is not a concern since the squib valves are leaktight and other potential leakage flow paths have double isolation.

Pressurizer safety line from the pressurizer to the safety valve
This line is steam filled and will not experience stratified loadings.

Automatic depressurization stage 2 and 3 lines from the pressurizer to the depressurization valves
Leakage is not a concern since double isolation exists in all potential leakage flow paths.

Normal residual heat removal suction lines from the hot legs to the isolation valves
Thermal stratification in the normal residual heat removal suction lines, including leakage through the isolation valves, is considered in the ASME pipe stress and fatigue analysis of these lines.

Direct vessel injection lines
Thermal stratification in the direct vessel injection lines, including leakage through the isolation vavles, is considered in the ASME Code pipe stress and fatigue analysis of these lines.

Main Steam Line

The steam lines are not subjected to thermal stratification by the nature of fluid transported.

Based on the above discussion, thermal stratification does not have an adverse effect on the integrity of AP1000 leak-before-break piping systems.

3B.2.7 Other Mechanisms

The pipe evaluated for leak-before-break does not operate at temperature for which creep fatigue must be considered. Creep fatigue is a concern for ferritic steel piping operation at temperatures above 700°F and for austenitic stainless steel operation above 800°F.

Pipe degradation or failure by indirect causes such as fires, missiles, and component support failures is precluded by criteria for design, fabrication, inspection, and separation of potential hazards in the vicinity of the safety-related piping. The structures, larger pipe, and components in the vicinity of pipe evaluated for leak-before-break are safety-related and seismically designed or are seismically supported if nonsafety-related.

Cleavage type failures are not a concern for systems operating temperature and material used in the stainless steel piping systems. The material used in the main steam line is highly ductile and resistant to cleavage type failure at operating temperatures. The resistance to failure have been demonstrated by material fracture toughness tests.

3B.3 Leak-before-Break Bounding Analysis

The methodology used for performing the bounding analysis is consistent with that set forth in GDC-4, SRP 3.6.3 (Reference 1) and NUREG-1061, Volume 3 (Reference 2).

Bounding leak-before-break analysis for the applicable AP1000 piping systems is performed. The analysis criteria and development techniques of the bounding analysis curves (BAC) are described below. The bounding analysis curve allows for the evaluation of the piping system in advance of the final piping analysis, incorporating leak-before-break considerations early in the piping design process. The leak-before-break bounding analysis curve is used to evaluate critical points in the piping system. A minimum of two points are required to develop the bounding analysis curve. One point for the low normal stress case and the other point for the high normal stress case. If variations in pipe size, material, pressure or temperature occur for a specific piping system, an additional bounding analysis curve is generated. These points meet the following margins for leak-before-break analysis: (References 1 and 2).

- Margin of 10 on leak detection capability
- Margin of 2 on flaw size
- Establish margin of 1 on load by using absolute combination method of maximum loads

The calculations to establish the bounding analysis curves use minimum values for wall thickness at the weld counterbore and ASME Code material properties. For the main steam line lower bound material property values determined from tests of the material are used. The use of the minimum values bounds the results of larger values. Since the piping is designed and analyzed using ASME Code minimum material properties, these are used conservatively in a consistent manner for evaluation of leak-before-break evaluations. The as-built material properties are expected to be higher than the ASME Code minimum properties. Using minimum thickness instead of a nominal thickness is conservative for the stability analysis and was also used for leak-before-break in operating plants. The use of one thickness (either nominal or minimum) for both leak rate and stability calculation gives comparable overall margins for typical plant loads. The bounding analysis curves are established using the axial load from internal pressure and neglecting other axial loads. This is an appropriate approximation because experience with leak-before-break calculations has shown that the axial load due to pressure is the dominant axial load.

3B.3.1 Procedure for Stainless Steel Piping

3B.3.1.1 Pipe Geometry, Material and Operating Conditions

The following information is identified for each of the lines:

- Piping materials - 316LN/304L, Type 304L is used for the accumulator discharge line
- Normal operating temperature
- Normal operating pressure
- Pipe outside diameter
- Pipe thickness

The number of bounding analysis curves needed for each analyzable piping system is determined by a review of the combinations of the following parameters:

- Pipe size
- Pipe schedule
- Operating pressures (100 percent power and maximum stress condition)
- Operating temperatures (100 percent power and maximum stress condition)

3B.3.1.2 Pipe Physical Properties

The physical and metallurgical properties for each of the lines are determined in the following manner

- Minimum wall thickness is calculated at the weld counterbore
- The area (A) and section modulus (Z) are calculated using minimum wall thickness
- The yield strength is the ASME Code, Section II (Reference 5) minimum value, at temperature of interest
- The ultimate strength is the ASME Code, Section II (Reference 5) minimum value, at temperature of interest
- The modulus of elasticity is the ASME Code, Section II (Reference 5) at temperature of interest

3B.3.1.3 Low Normal Stress Case (Case 1)

To determine the first point of the bounding analysis curve the following steps are used.

- Calculate axial force Fp (for normal operating pressure)
- Assume a lower magnitude of bending stress. The magnitude selected is a very small number that is lower than the expected minimum bending stress.
- Calculate bending moment = (bending stress) x (section modulus)
- Calculate the leakage flaw size at 100 percent power condition for 10 times the leak detection capability (for 0.5 gpm leak detection capability, this is 10 x 0.5 = 5 gpm)
- Perform the stability analysis using the limit load methodology to obtain the critical flaw size. For AP1000 piping systems, there is no cast material and the weld process is gas tungsten arc welds (Z factor is 1.0 since weld process is gas tungsten arc welds, Reference 1.)
  - Determine the maximum loads for a critical flaw size of twice the leakage flaw size. The margin of 2 on flaw size is satisfied.
- Calculate the low normal stress and corresponding maximum stress by using:

$$\text{Stress} = \frac{\text{Axial Force}}{\text{Area}} + \frac{\text{Bending Moment}}{\text{Section Modulus}} \qquad \text{(3B-1)}$$

3B.3.1.4 High Normal Stress Case (Case 2)

To determine the other endpoint of the bounding analysis curve the following steps are used.

- Axial force Fp is calculated as above for normal operating pressure

- Assume a higher magnitude of bending stress to get higher bending moment. The magnitude of bending is selected such that the corresponding maximum stress generated is close to the flow stress.

- Calculate bending moment = (bending stress) x (section modulus)

- Repeat leakage flaw size and stability calculations as outlined for the low normal stress case above

Note: For an intermediate point, calculation steps are the same as low normal or the high normal case.

3B.3.1.5 Develop the Bounding Analysis Curve

- For Case 1, normal and maximum stresses are established.

- For Case 2, normal and maximum stresses are established.

- Plot these two points with normal versus maximum stress. The curve is generated by joining these two points in a straight line. More than two points may be used if desired, to obtain a smooth curve fit between the calculated points. A typical curve is shown in Figure 3B-1.

3B.3.2 Procedure for Non-stainless Steel Piping

The procedure to develop the bounding analysis curve for the carbon steel for main steam lines is similar to that for the stainless steel and is described below.

3B.3.2.1 Pipe Geometry, Material and Operating Conditions

The following information is identified for each of the lines:

- Piping materials
- Normal operating temperature
- Normal operating pressure
- Pipe outside diameter
- Piping thickness

The number of bounding analysis curves needed for each analyzable piping system is determined by a review of the combinations of the following parameters:

- Pipe size
- Pipe schedule
- Operating pressures (100 percent power and maximum stress condition)
- Operating temperatures (100 percent power and maximum stress condition)

3B.3.2.2 Calculations Steps

- The minimum wall thickness is calculated at the weld counterbore

- The area (A) and section modulus (Z) are calculated using minimum wall thickness

- The material yield strength, ultimate strength, modulus of elasticity, stress-strain curves, and J-R curves are determined from the material tests

3B.3.2.3 Low Normal Stress Case (Case 1)

To determine the first point of the bounding analysis curve the following steps are used.

- Calculate axial force Fp (for normal operating pressure)
- Assume a lower magnitude of bending stress
- Calculate bending moment = (bending stress) x (section modulus)
- Calculate the leakage flaw size at 100 percent power condition for 10 times the leak detection capability (for 0.5 gpm leak detection capability, this is 10 x 0.5 = 5 gpm)
- Stability analysis
  - Perform J-integral analysis
  - Determine the maximum loads for a critical flaw size of twice the leakage flaw size by satisfying the stability criteria. The margin of 2 on flaw size is satisfied.
- Stability criteria
  - Japplied ≤ JIC
  - If Japplied > JIC, then Japplied < Jmax and Tapplied < Tmat
- Calculate the low normal stress and corresponding maximum stress by using:

$$\text{Stress} = \frac{\text{Axial Force}}{\text{Area}} + \frac{\text{Bending Moment}}{\text{Section Modulus}}$$

3B.3.2.4 High Normal Stress Case (Case 2)

To determine the other endpoint of the bounding analysis curve the following steps are used.

- Axial force Fp is calculated above (for normal operating pressure)
- Assume a higher magnitude of bending stress to get higher bending moment
- Calculate bending moment = (bending stress) x (section modulus)
- Repeat leakage flaw size and stability calculations as outlined for the low normal stress case above

Note: For an intermediate point, calculation steps are the same as low normal or the high normal case.

3B.3.2.5 Develop the Bounding Analysis Curve

Follow steps as outlined for the stainless steel case in subsection 3b.3.1.5.

3B.3.3 Evaluation of Piping System Using Bounding Analysis Curves

To evaluate the applicability of leak-before-break, the results of the pipe stress analysis are compared to the bounding analysis curve. The critical location is the location of highest maximum stress as determined by the pipe stress results. A comparison is made with the applicable bounding analysis curves for the analyzable piping systems. As outlined in 3B.3.1.1 and 3B.3.2.1, bounding analysis curves are calculated for different combinations of pipe size, pipe schedule, operating pressures, operating temperatures.

The bounding analysis curves are used during the layout and design of the piping systems to provide a design that satisfies leak-before-break criteria. In addition, the results of the as-built piping analysis reconciliation to the bounding analysis curves to verify that the fabricated piping systems satisfy leak-before-break criteria. See subsection 3.6.4 for the Combined License information item associated with this verification.

At the critical location, the load combination for the maximum stress calculation uses the absolute sum method. The load combination is as follows:

(1) |Pressure| + |Deadweight| + |Thermal (100% Power)*| + |Safe Shutdown Earthquake|

The normal stress is calculated using the algebraic sum method at critical location and the following load combination.

(1) Pressure + Deadweight + Thermal (100% Power*)

* Includes applicable stratification loads.

3B.3.3.1 Calculation of Stresses

The stresses due to axial loads and moments are calculated by the following equation:

where:

$$\sigma = \frac{F}{A} + \frac{M}{Z} \qquad \text{(3B-2)}$$

σ = stress

F = axial load

M = moment

A = cross-sectional area

Z = section modulus

The moments for the desired loading combinations are calculated by the following equation:

$$M = \sqrt{M_X^2 + M_Y^2 + M_Z^2} \qquad \text{(3B-3)}$$

where,

M = moment for required loading

M_X = torsional moment

M_Y = Y component of bending moment

M_Z = Z component of bending moment

The Y and Z-axes are lateral axes to the X-axis which is the axial axis

The axial load and moments for the normal case and maximum case are computed by the methods shown below.

3B.3.3.2 Normal Loads

The normal operating loads are calculated by the following equations:

$$F = F_{DW} + F_{Th} + F_P \quad (3B-4)$$

$$M_X = (M_X)_{DW} + (M_X)_{Th} \quad (3B-5)$$

$$M_Y = (M_Y)_{DW} + (M_Y)_{Th} \quad (3B-6)$$

$$M_Z = (M_Z)_{DW} + (M_Z)_{Th} \quad (3B-7)$$

The subscripts of the above equations represent the following load cases:

DW = deadweight

Th = normal thermal expansion (100 percent power, including applicable stratification loads)

P = load due to internal pressure

The method of combining loads is often referred to as the algebraic sum method.

Calculate the normal stress at the critical location.

3B.3.3.3 Maximum Loads

For the maximum case, the absolute summation method of load combination is applied which results in higher magnitude of the combined loads. Since stability is demonstrated using these loads, the leak-before-break margin on loads is satisfied. An example of the absolute summation expressions are shown below:

$$F = |F_{DW}| + |F_{Th}| + |F_P| + |F_{SSEINERTIA}| + |F_{SSEAM}| \quad (3B-8)$$

$$M_X = |(M_X)_{DW}| + |(M_X)_{Th}| + |(M_X)_{SSEINERTIA}| + |(M_X)_{SSEAM}| \quad (3B-9)$$

$$M_Y = |(M_Y)_{DW}| + |(M_Y)_{Th}| + |(M_Y)_{SSEINERTIA}| + |(M_Y)_{SSEAM}| \quad (3B-10)$$

$$M_Z = |(M_Z)_{DW}| + |(M_Z)_{Th}| + |(M_Z)_{SSEINERTIA}| + |(M_Z)_{SSEAM}| \quad (3B-11)$$

where subscripts SSE, Inertia and AM mean safe shutdown earthquake, inertia and anchor motion respectively.

3B.3.3.4 Bounding Analysis Curve Comparison – LBB Criteria

To compare the stress results with the bounding analysis curve the following process is followed. The normal and maximum stress at the critical location are calculated by using the loads defined in subsection 3b.3.3. Plot the normal stress versus maximum stress on the bounding analysis curve for the specified system. If the point is on or below the bounding analysis curve, the leak-before-break analysis and margins are satisfied. If the point falls above the bounding analysis curve, the leak-before-break analysis criteria are not satisfied and the pipe layout or support configuration needs to be revised to meet the leak-before-break bounding analysis. Figure 3B-1 shows a typical bounding analysis curve.

3B.3.4 Bounding Analysis Results

Table 3B-1 shows a summary of piping systems and corresponding bounding analysis figures. Figures 3B-1 to 3B-22 show the bounding analysis curves. The curves satisfy the margins as indicated in Section 3B.3.

3B.4 Differences in Leak-before-Break Analysis for Stainless Steel and Ferritic Steel Pipe

The significant difference between leak-before-break analysis performed for the stainless steel (Class 1 and Class 3) systems and the ferritic steel in the Class 2 systems is in the stability analysis. In the case of stainless steel systems, stability analyses are performed by limit load approach. In the ferritic steel systems, stability analyses are performed by J-integral approach.

3B.5 Differences in Inspection Criteria for Class 1, 2, and 3 Systems

Class 1, 2 and 3 systems are subjected to in-service inspection requirements from ASME Code, Section XI. For Class 1 piping, terminal ends and dissimilar metal welds are volumetrically inspected, along with other locations, to total 25 percent of the welds. For Class 2 piping, the requirement is to volumetrically inspect the terminal ends and other locations to total 7.5 percent of the welds. For Class 3 systems (the only Class 3 piping is in the accumulator line which is always at room temperature), the system receives periodic visual examinations in conjunction with pressure testing. These requirements were developed by ASME Code, Section XI consistent with the different safety classes of these systems.

The leak-before-break evaluations are based on the ability to detect a potential leaking crack; not the ability to find cracks by inservice inspections. The criteria or methods of the leak-before-break evaluations are the same for ASME Code Class 1, 2, and 3.

3B.6 Differences in Fabrication Requirements of ASME Class 1, Class 2, and Class 3 Piping

The significant difference among Class 1, 2 and 3 seamless pipe occurs in the nondestructive examination requirements. The Class 1 seamless pipe examination requirements include an ultrasonic testing examination, whereas Class 2 and 3 do not. In addition, the Class 1 examination requirements for a circumferential butt welded joint include radioagraphic testing and magnetic particle or liquid penetrant examination where Class 2 does not. The examination requirements for Class 2 pipe require radiographic examination of the welds and normally Class 3 pipe does not. As noted in subsection 3.2.2.5, for Class 3 lines required for emergency core cooling functions, radiography will be conducted on a random sample of welds. The Class 3 leak-before-break lines are included in the lines that are radiographed. In addition see subsection 3.6.3.2 for augmented inspection of Class 3 leak-before-break lines.

For the fabrication of welds in the Class 1, Class 2 and Class 3 pipes there is no significant differences.

The differences in fabrication and nondestructive examination requirements do not affect the leak-before-break analyses assumptions, criteria, or methods.

3B.7 Sensitivity Study for the Constraint Effect on LBB

Westinghouse performed a sensitivity study on a 6-inch diameter pipe to demonstrate that the leak-before-break evaluation margins are not significantly affected when constraint effects of pressure induced bending are included. The analysis used a finite element model of a 6-inch diameter pipe welded to a nozzle with a fixed end condition. This conservatively represents the bounding conditions for AP1000 piping. The normal and maximum stresses were used from a representative AP600 6-inch line bounding analysis curve. The material properties for the base metal and TIG weld were considered in the analysis. The stability analysis was performed using the J-integral method. This analysis was developed in consultation with the NRC.

The conclusion of this sensitivity study is that the leak-before-break margins for 6-inch and larger piping on AP1000 are not significantly affected by the constraint effect and application of leak-before-break to such piping is acceptable.

3B.8 References

1. Standard Review Plan 3.6.3, "Leak Before Break Evaluation Procedures," Federal Register, Volume 52, Number 167, Friday, August 28, 1987; Notice (Public Comment Solicited), pp. 32626-32633.

2. NUREG-1061, "Evaluation of Potential for Pipe Breaks, Report of the U.S. Nuclear Regulatory Commission Piping Review Committee," Volume 3, (prepared by the Pipe Break Task Group), November 1984.

3. "Erosion-Corrosion in Nuclear Plant Steam Piping: Causes and Inspection Program Guidelines," EPRI NP-3944, April 1985.

4. G. Cragnolino, "Erosion-Corrosion in Nuclear Power Systems-An Overview," Corrosion '87, Paper No. 86, March 1987.

5. ASME Boiler and Pressure Vessel Code, Section II, "Materials," 1998 Edition through 2000 Addenda.

Table 3B-1 (Sheet 1 of 2)
AP1000 Leak-Before-Break Bounding Analysis Systems and Parameters

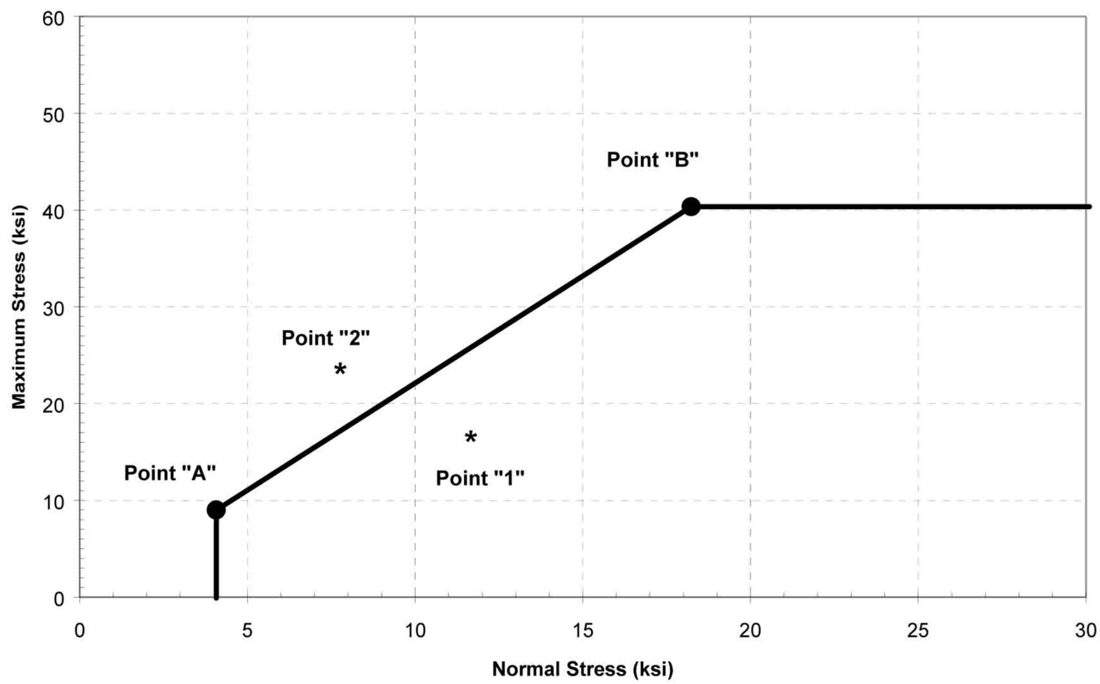
System	Subsystem	Line No(s).	Nominal Diameter (Inches)	Material	Temp (°F)	Pressure (psig)	Figure No.
RCS	Primary Loop Hot Leg	L001A, B	31 (ID)(1)	SA-376 TP316LN	610.0	2248	3B-2
RCS	Primary Loop Cold Leg	L002A, B, C, D	22 (ID)(1)	SA-376 TP316LN	537.2	2310	3B-3
SGS	Main Steam Line	L006A, B	38	SA-335 GR P11	523.0	821	3B-4
RCS	Normal Residual Heat Removal	L139	20	SA-312 TP316LN	610.0	2248	3B-5
RCS	Surge Line	L003	18	SA-312 TP316LN	653.0	2248	3B-6 (Sheet 1)
RCS	Surge Line	L003	18	SA-312 TP316LN	455.0	430	3B-6 (Sheet 2)
RCS	Passive Residual Heat Removal Supply/ ADS 4	L135A,B; L136A,B	18	SA-312 TP316LN	610.0	2248	3B-7
RCS	Passive Removal Heat Removal Supply/ ADS 4	L133A, B; L137A, B; L134	14	SA-312 TP316LN	610.0	2248	3B-8
PXS	Passive Residual Heat Removal Supply to Cold Trap and Vent Line	L102, L107	14	SA-312 TP316LN	610.0	2248	3B-8
PXS	Passive Residual Heat Removal Supply after Cold Trap to PRHR HX	L102	14	SA-312 TP316LN	120.0	2248	3B-9
PXS	Return – PRHR HX to Isolation Valve	L103; L104A, B	14	SA-312 TP316LN	120.0	2248	3B-9
RCS	Automatic Depressurization System Stage 2, 3	L004A,B; L006A,B; L020A,B; L030A, B; L131	14	SA-312 TP316LN	653.0	2235	3B-10
PXS	Passive Residual Heat Removal Return – after Isolation Valve	L104A, B; L105	14	SA-312 TP316LN	537.0	2190	3B-11

Table 3B-1 (Sheet 2 of 2)
AP1000 Leak-Before-Break Bounding Analysis Systems and Parameters

System	Subsystem	Line No(s).	Nominal Diameter (Inches)	Material	Temp (°F)	Pressure (psig)	Figure No.
RCS	Passive Residual Heat Removal Return	L113	14	SA-312 TP316LN	537.0	2190	3B-11
PXS	Passive Residual Heat Removal Vent Line	L107	12	SA-312 TP316LN	610.0	2248	3B-12 (Not Used)
PXS	Accumulator to Isolation Valve	L029A, B	8	SA-312 TP304L	120.0	700	3B-13
RCS	Balance Line from Cold Leg to CMT Isolation Valve	L118A, B	8	SA-312 TP316LN	537.0	2310	3B-14
PXS	Balance Line from CMT Isolation Valve to CMT	L007A, B; L070A, B	8	SA-312 TP316LN	537.0	2310	3B-14
PXS	Direct Vessel Injection Line to RV	L021A, B; L125A, B	8	SA-312 TP316LN	537.0	2310	3B-14
PXS	Core Makeup Tank (Injection Line, RV Side of Isolation Valve, Core Makeup Tank Side of Isolation Valve), Direct Vessel Injection (Accumulator Connection to Cold Trap), IWRST Injection	L015, L016, L017, L018, L020, L021, L025, L127 (All A, B)	8	SA-312 TP316LN	120.0	2310	3B-15
RCS	Automatic Depressurization System Stage 2, 3	L021A,B; L031A,B	8	SA-312 TP316LN	653.0	2235	3B-16 (Not Used)
PXS	Accumulator after Isolation Valve	L027A, B	8	SA-312 TP304L	120.0	700	3B-17
PXS	RNS Discharge	L019A, B	6	SA-312 TP316LN	120.0	2310	3B-18
RCS	Automatic Depressurization System Header to RCS Safety Valve	L005A, B	6	SA-312 TP316LN	653.0	2235	3B-19
RCS	Normal Residual Heat Removal	L140	12	SA-312 TP316LN	610.0	2248	3B-20
RNS	Normal Residual Heat Removal	L001, L002A, B	10	SA-312 TP316LN	610.0	2248	3B-21
RCS	Automatic Depressurization System Stage 2, 3 (Cold Trap)	L021A, B; L031A, B	8	SA-312TP316LN	250	2235	3B-22

Note:
1. ID = Inside diameter

AP1000
Typical Bounding Analysis Curve (BAC)
Line Number(s):



Pipe Designator:		Normal Operating Pressure:	psig
System:		Normal Operating Temperature:	F
Nominal Diameter:	inch	Critical Flaw Size = 2 x Leakage Flaw Size	
Pipe Schedule:		Load Margin = 1.0	
Outside Diameter:	inch	Leak Rate Margin = 10 (Typical for All Curves)	
Pipe Material:			
Minimum Weld Thickness:			

Notes for Typical Bounding Analysis Curve:
Point "A" - for low normal case to generate BAC.
Point "B" - for high normal case to generate BAC.
Point "A" and Point "B" are joined by a straight line.
Point "1" - analyzed critical point which meets LBB criteria.
Point "2" - analyzed critical point which fails LBB criteria.

Figure 3B-1 Typical Bounding Analysis Curve (BAC)

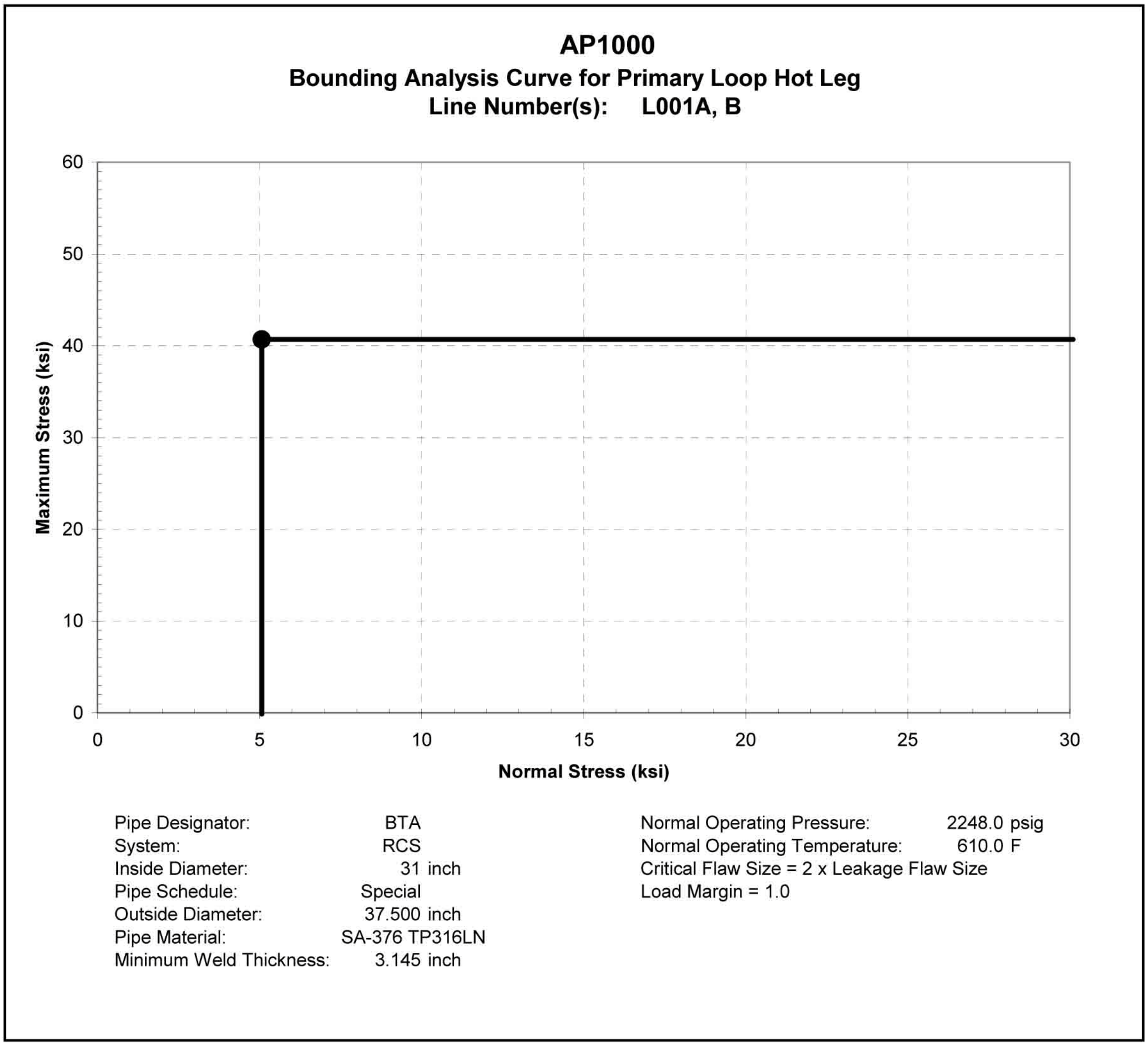


Figure 3B-2 Bounding Analysis Curve for Primary Loop Hot Leg

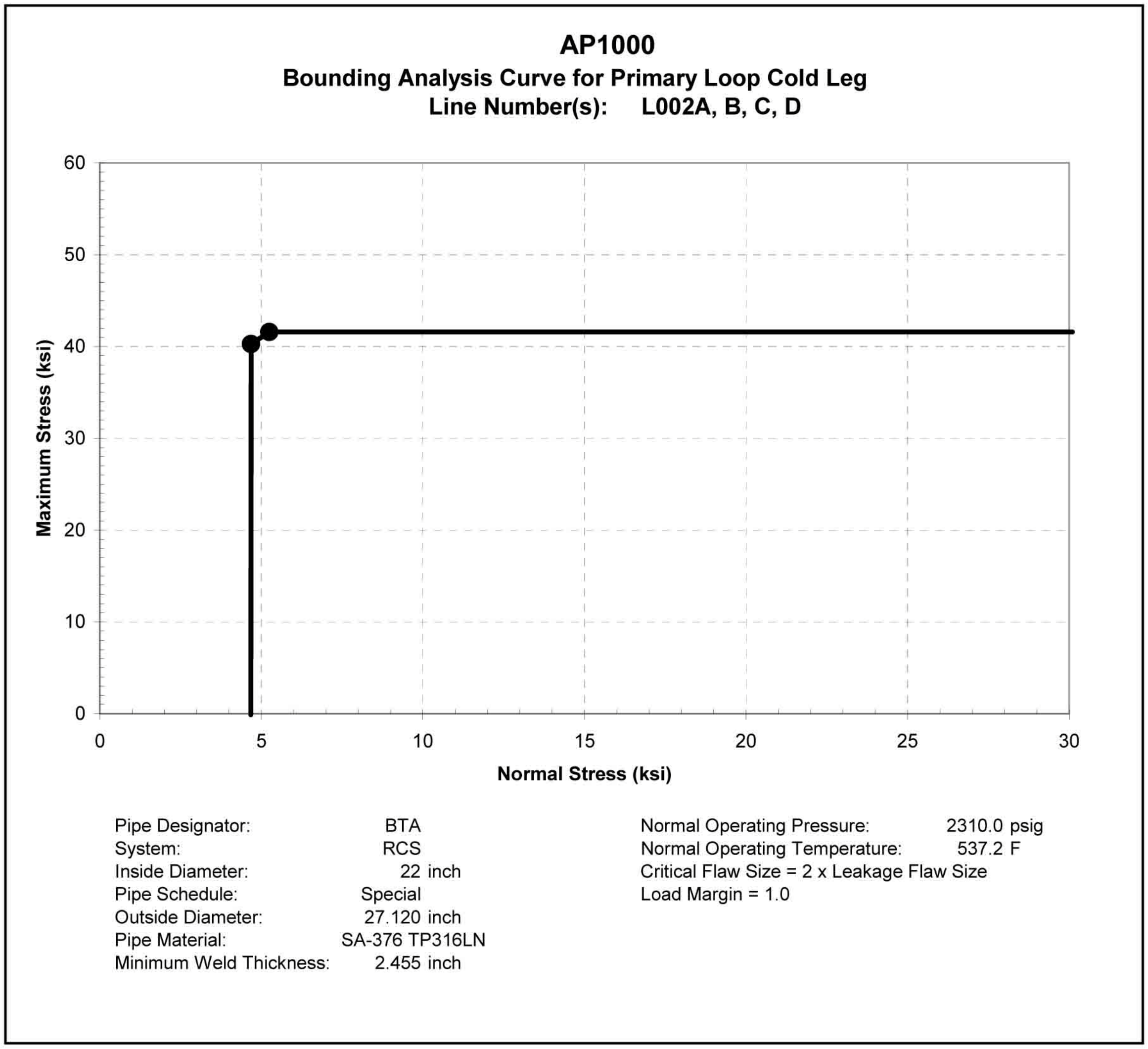
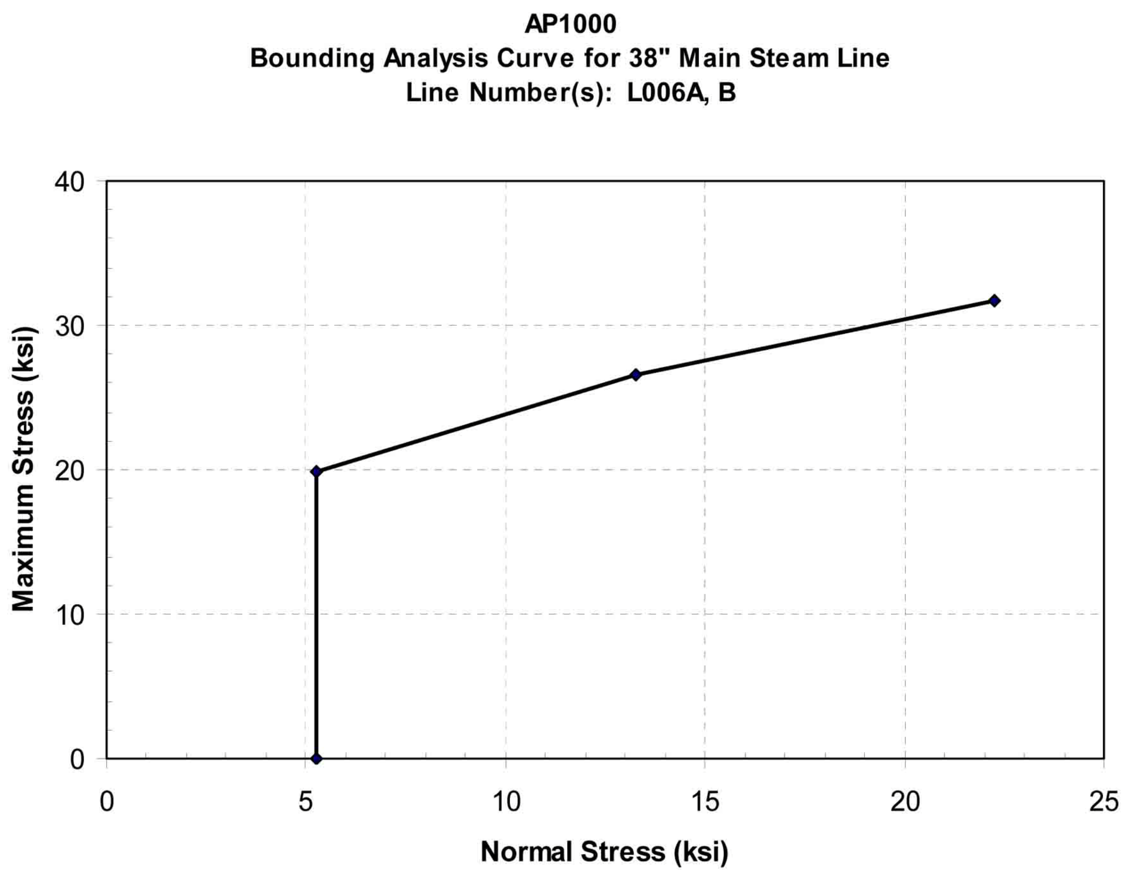


Figure 3B-3 Bounding Analysis Curve for Primary Loop Cold Leg



Pipe Designator:	EAB
System:	SGS
Nominal Diameter:	38.00 inch
Pipe Schedule:	Special
Outside Diameter:	38.000 inch
Pipe Material:	SA335 P11
Minimum Weld thickness:	1.599 inch

Normal Operating Pressure: 821 psig
Normal Operating Temperature: 523°F
Critical Flaw Size = 2 x Leakage Flaw Size
Load Margin = 1.0

Figure 3B-4 Bounding Analysis Curve for 38″ Main Steam Line

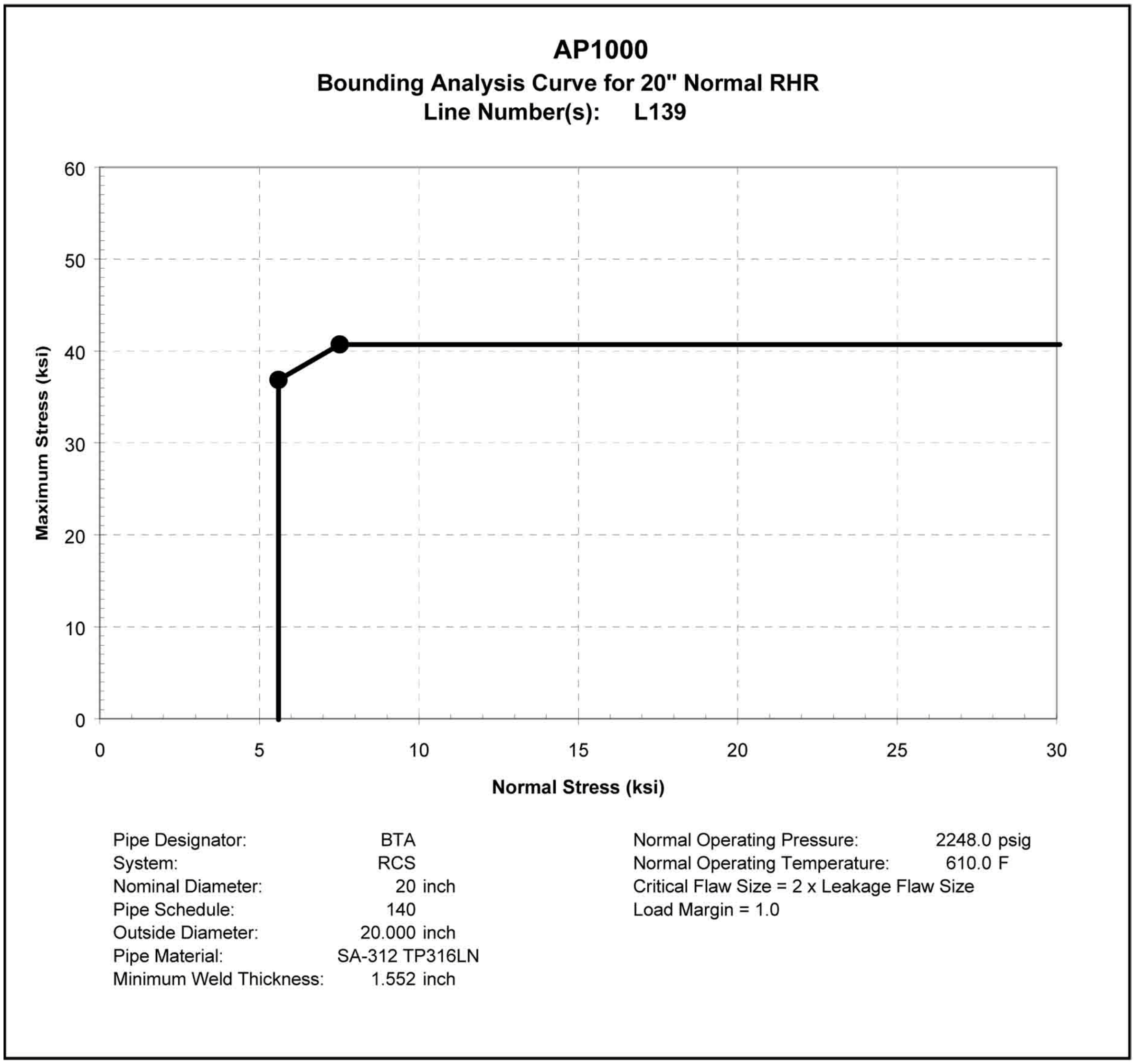


Figure 3B-5 Bounding Analysis Curve for 20″ Normal RHR

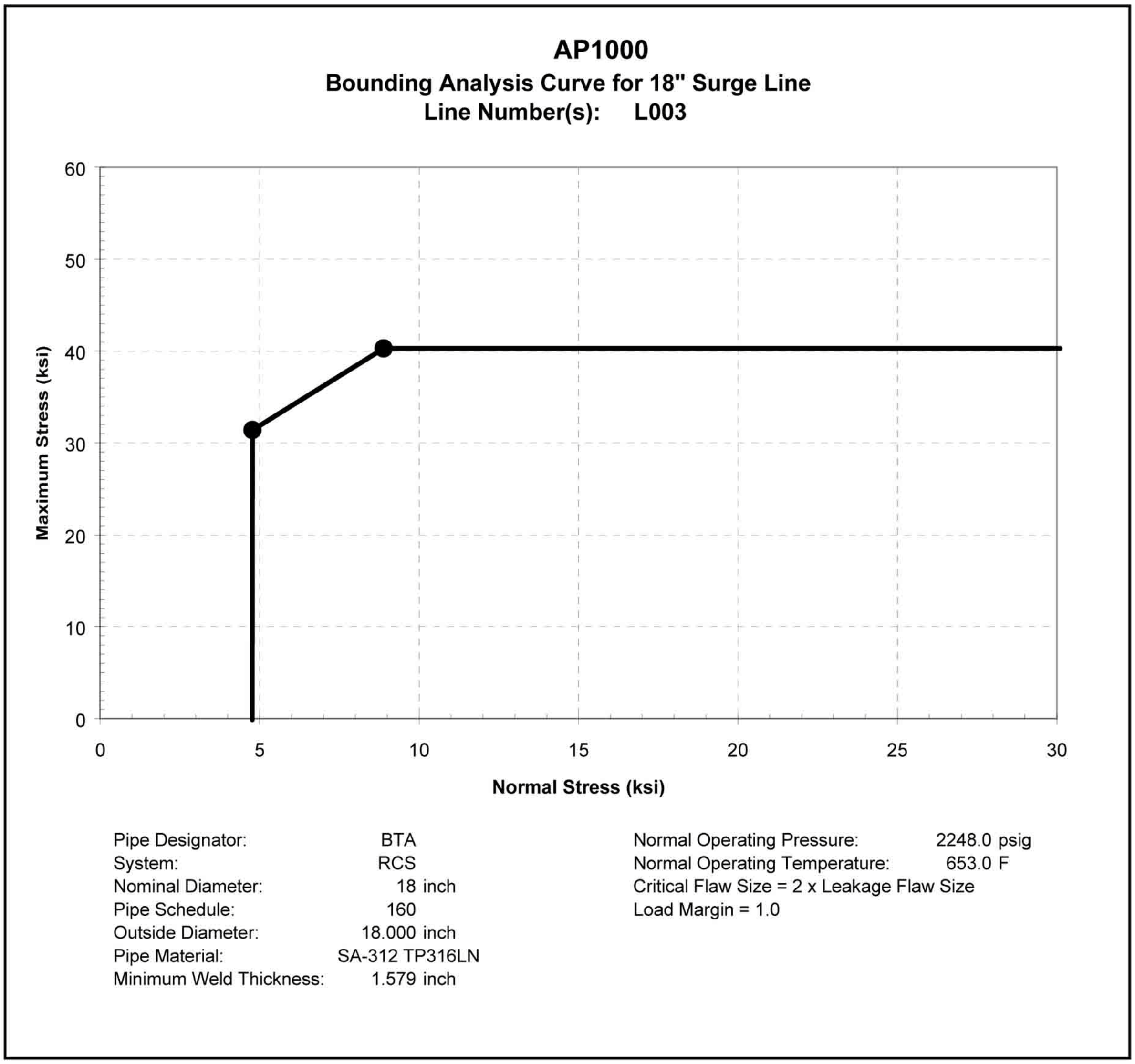
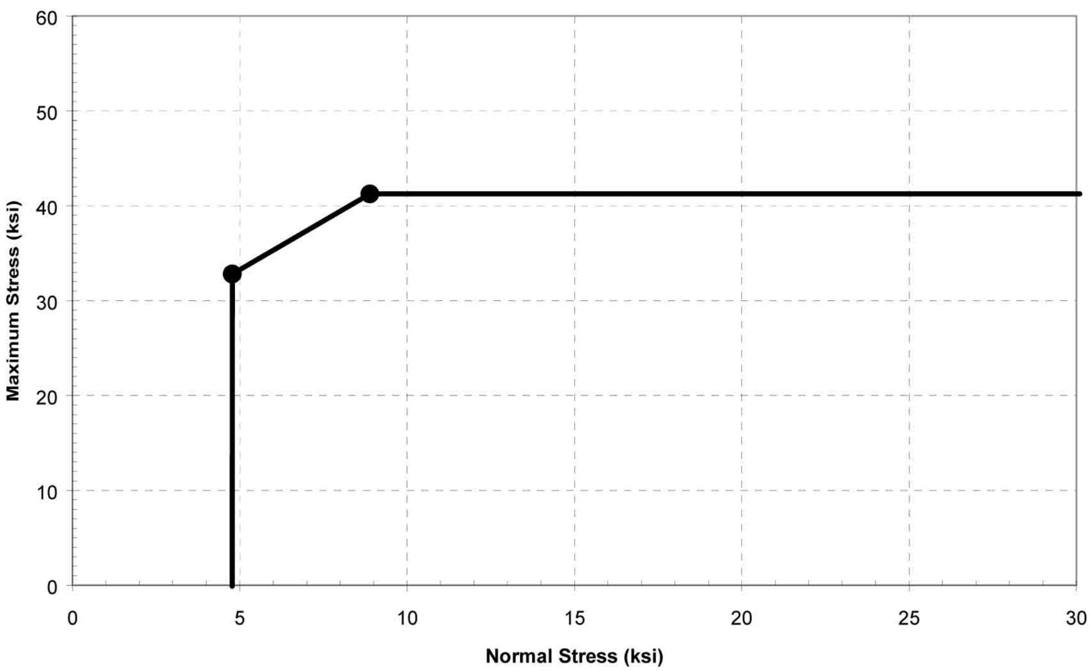


Figure 3B-6 (Sheet 1 of 2) Bounding Analysis Curve for 18″ Surge Line

AP1000
Bounding Analysis Curve for 18" Surge Line
Line Number(s): L003



Pipe Designator:	BTA	Normal Operating Pressure:	2248.0 psig
System:	RCS	Normal Operating Temperature:	653.0 F
Nominal Diameter:	18 inch	Critical Flaw Size = 2 x Leakage Flaw Size	
Pipe Schedule:	160	Load Margin = 1.0	
Outside Diameter:	18.000 inch		
Pipe Material:	SA-312 TP316LN	Pressure for Max. Stress Case:	430.0 psig
Minimum Weld Thickness:	1.579 inch	Temperature for Max. Stress Case:	455.0 F

Figure 3B-6 (Sheet 2 of 2) Bounding Analysis Curve for 18″ Surge Line

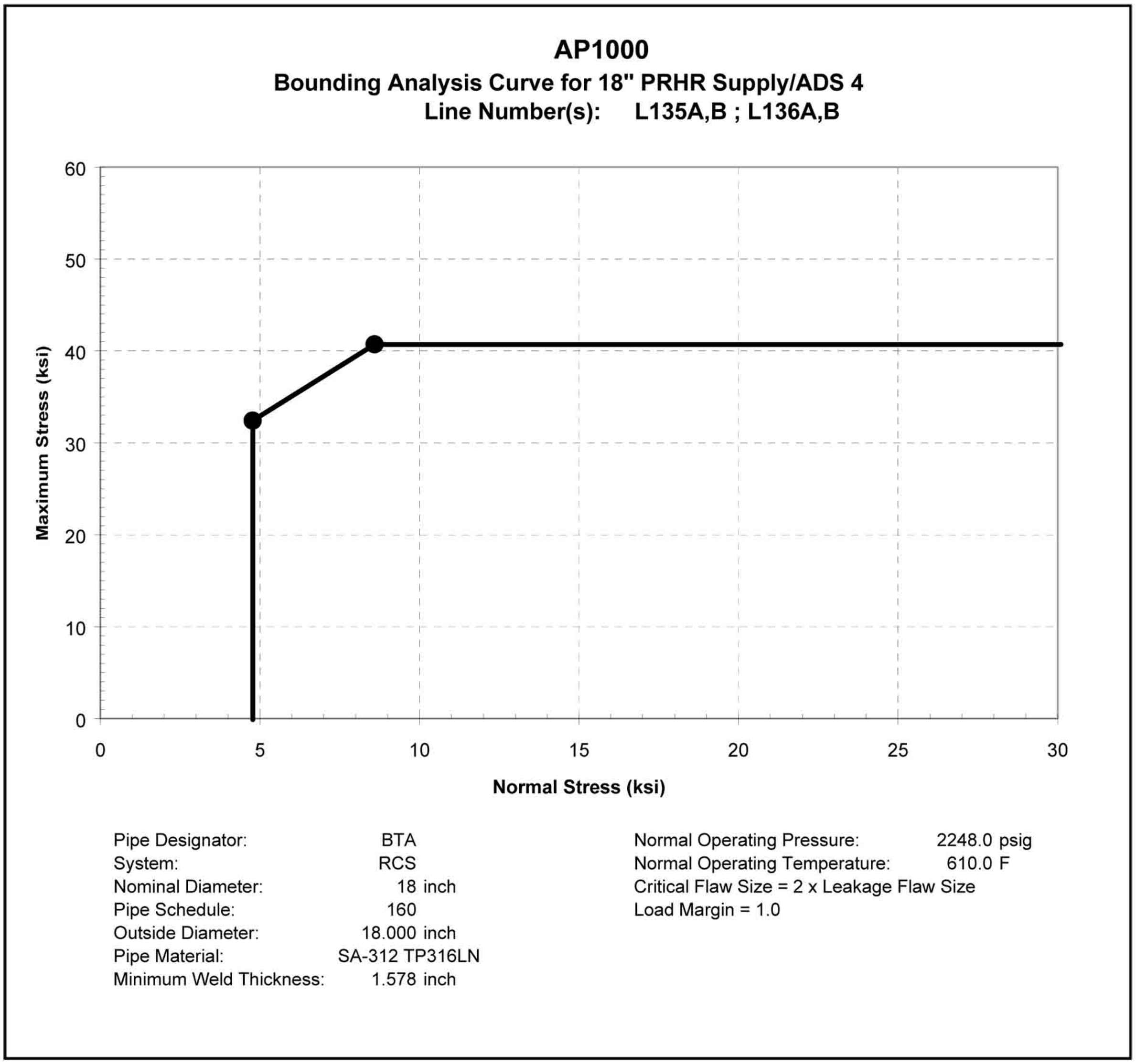


Figure 3B-7 Bounding Analysis Curve for 18″ PRHR Supply/ADS 4

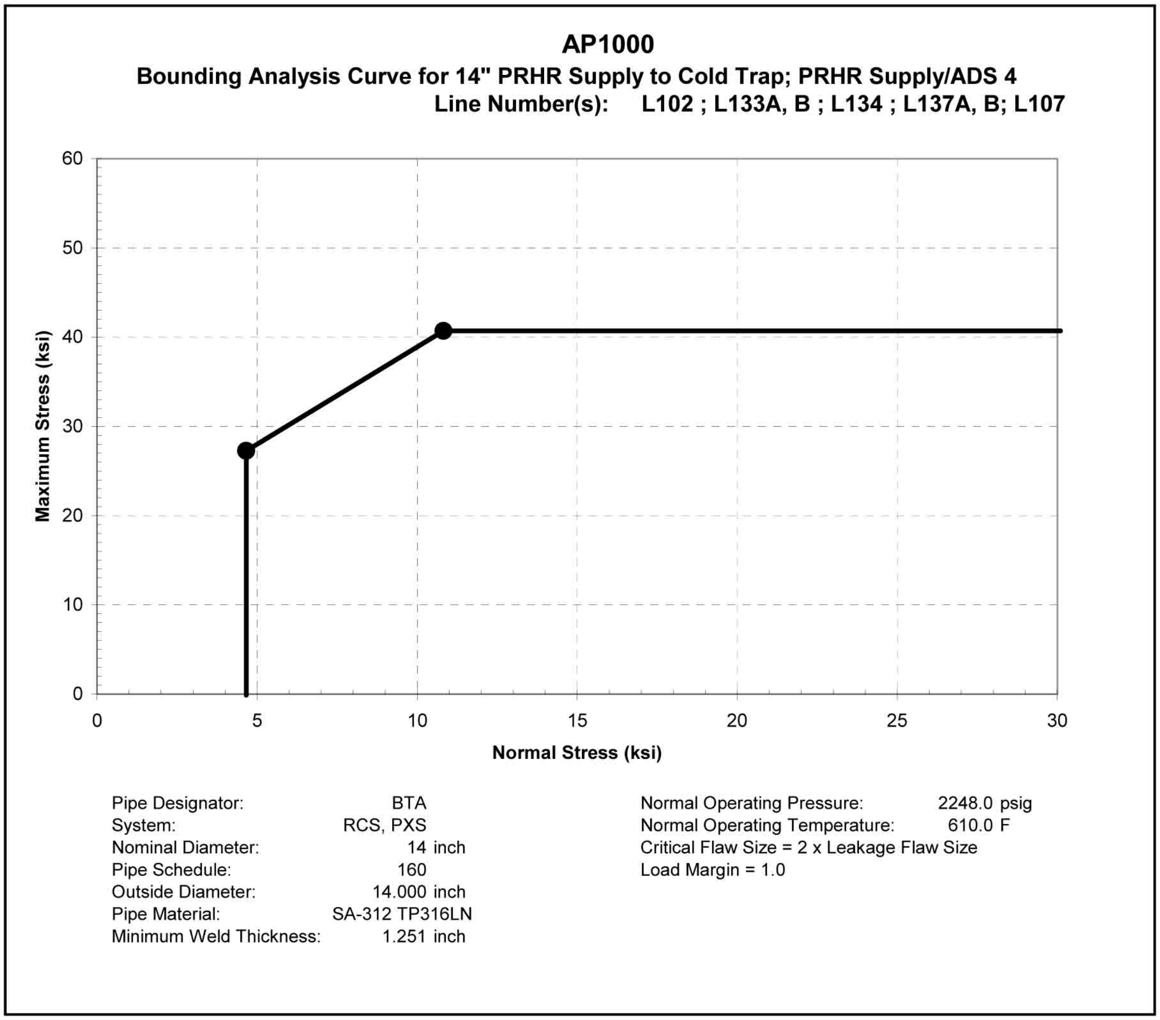
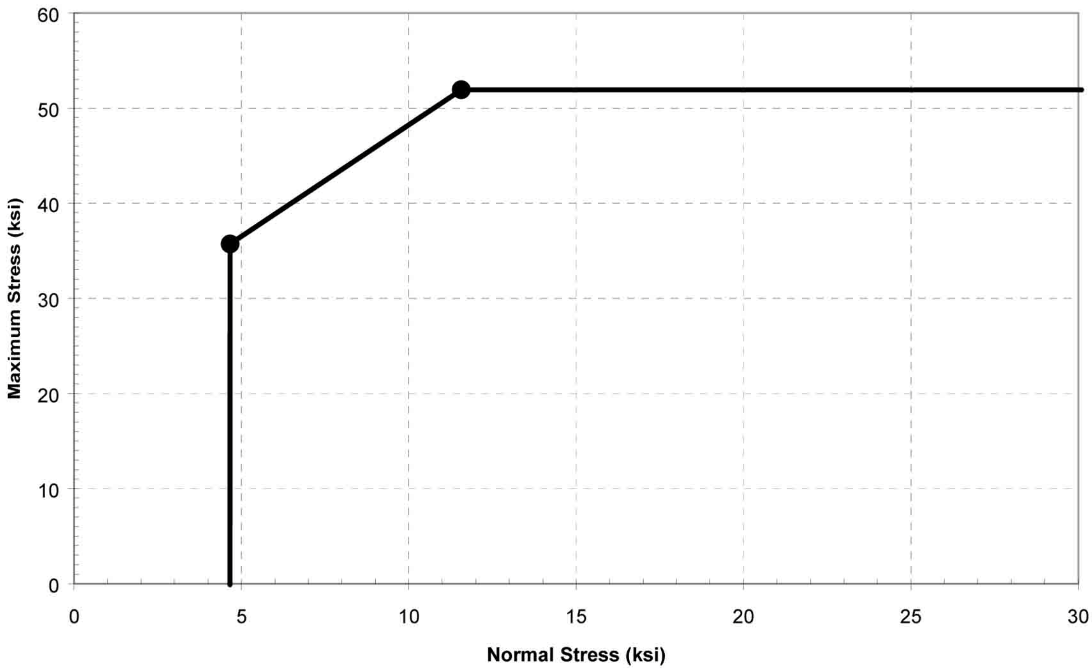


Figure 3B-8 Bounding Analysis Curve for 14″ PRHR Supply to Cold Trap, PRHR Supply/ADS4

AP1000

Bounding Analysis Curve for 14" PRHR Supply after Cold Trap, Return - to Isolation Valve

Line Number(s): L102 ; L103 ; L104A, B



Pipe Designator:	BTA	Normal Operating Pressure:	2248.0 psig
System:	RCS, PXS	Normal Operating Temperature:	120.0 F
Nominal Diameter:	14 inch	Critical Flaw Size = 2 x Leakage Flaw Size	
Pipe Schedule:	160	Load Margin = 1.0	
Outside Diameter:	14.000 inch		
Pipe Material:	SA-312 TP316LN		
Minimum Weld Thickness:	1.251 inch		

Figure 3B-9 Bounding Analysis Curve for 14″ PRHR Supply after Cold Trap, Return – to Isolation Valve

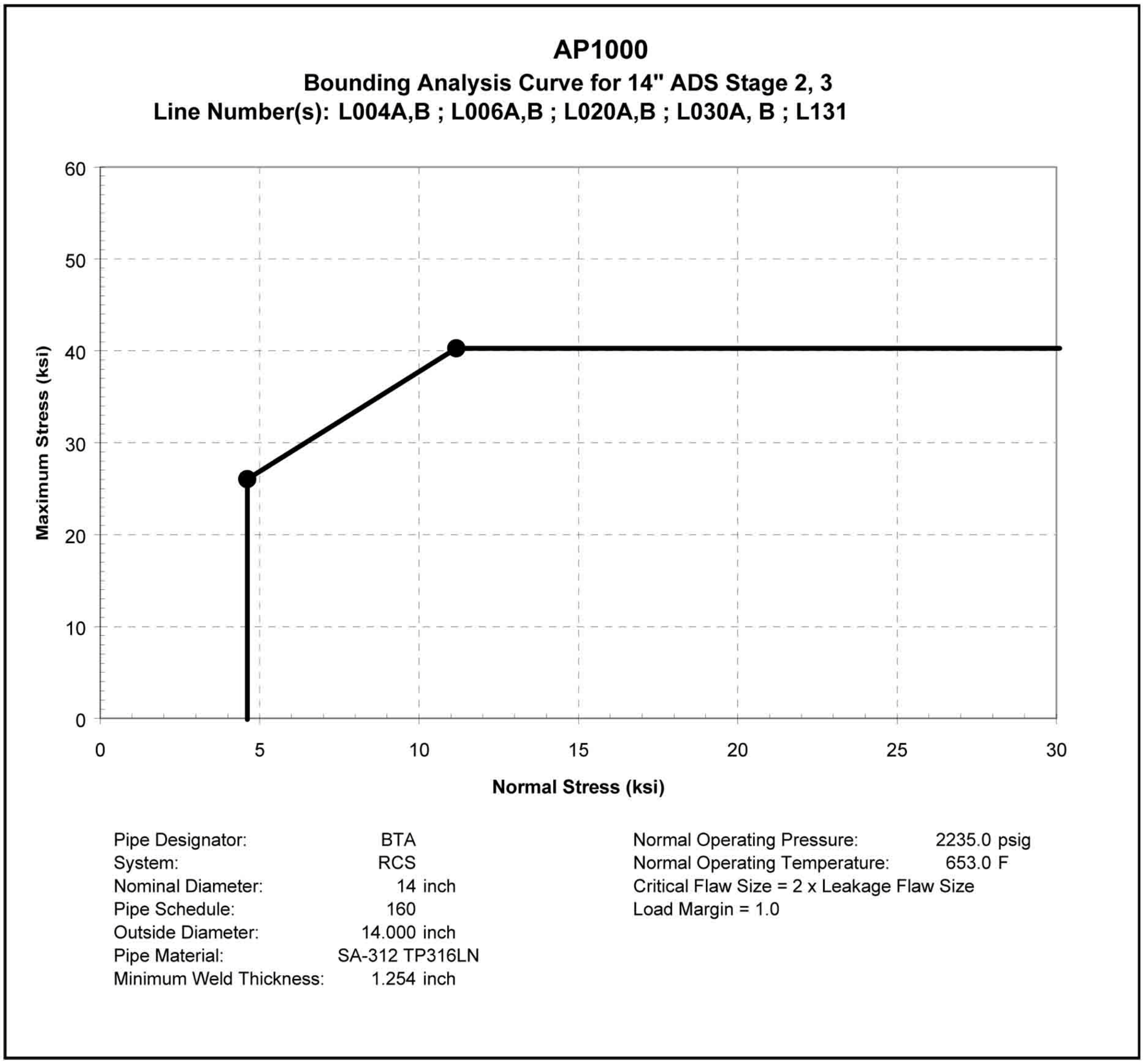


Figure 3B-10 Bounding Analysis Curve for 14″ ADS Stage 2, 3

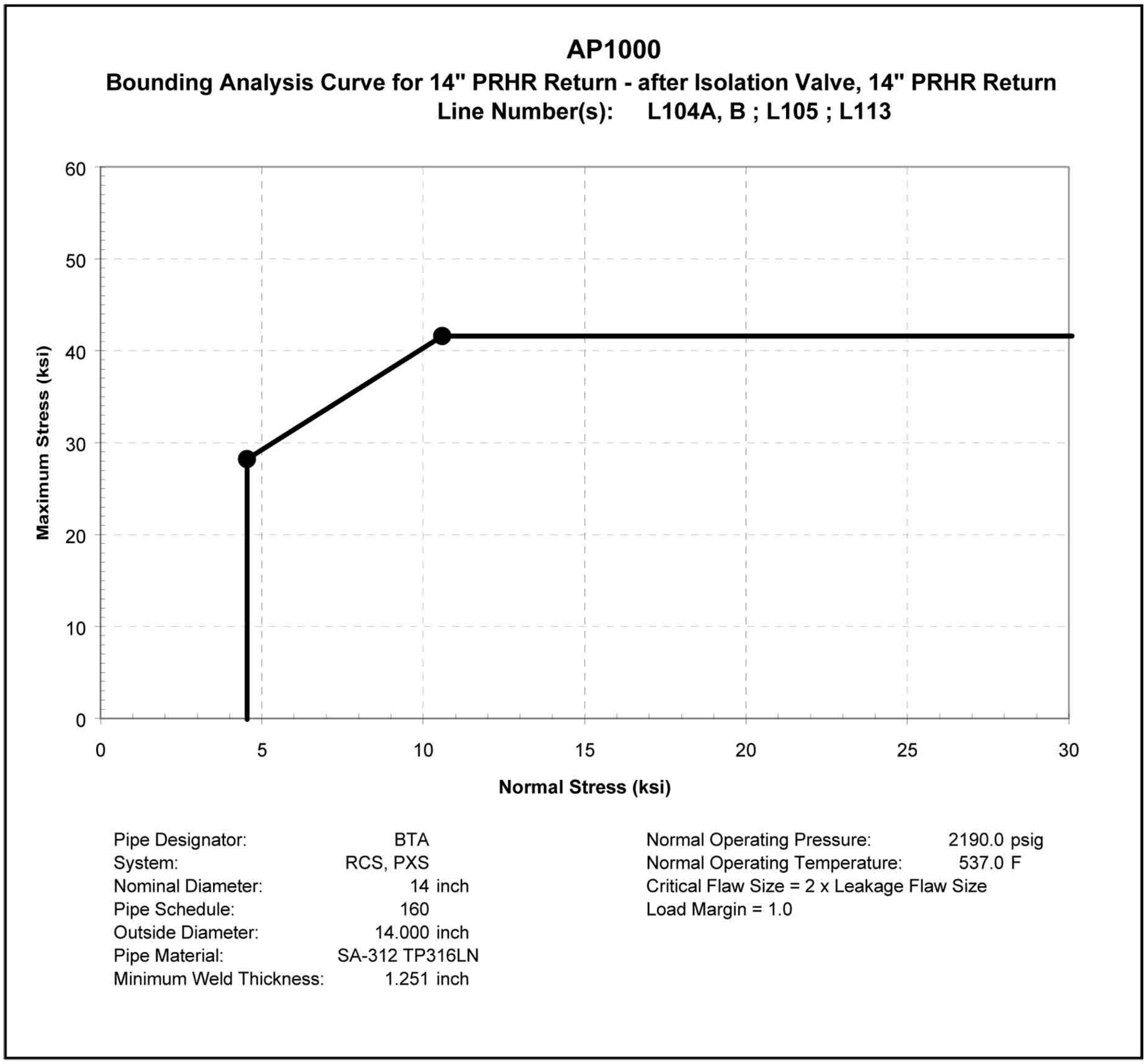


Figure 3B-11 Bounding Analysis Curve for 14″ PRHR Return – after Isolation Valve, 14″ PRHR Return

Figure 3B-12 not used.

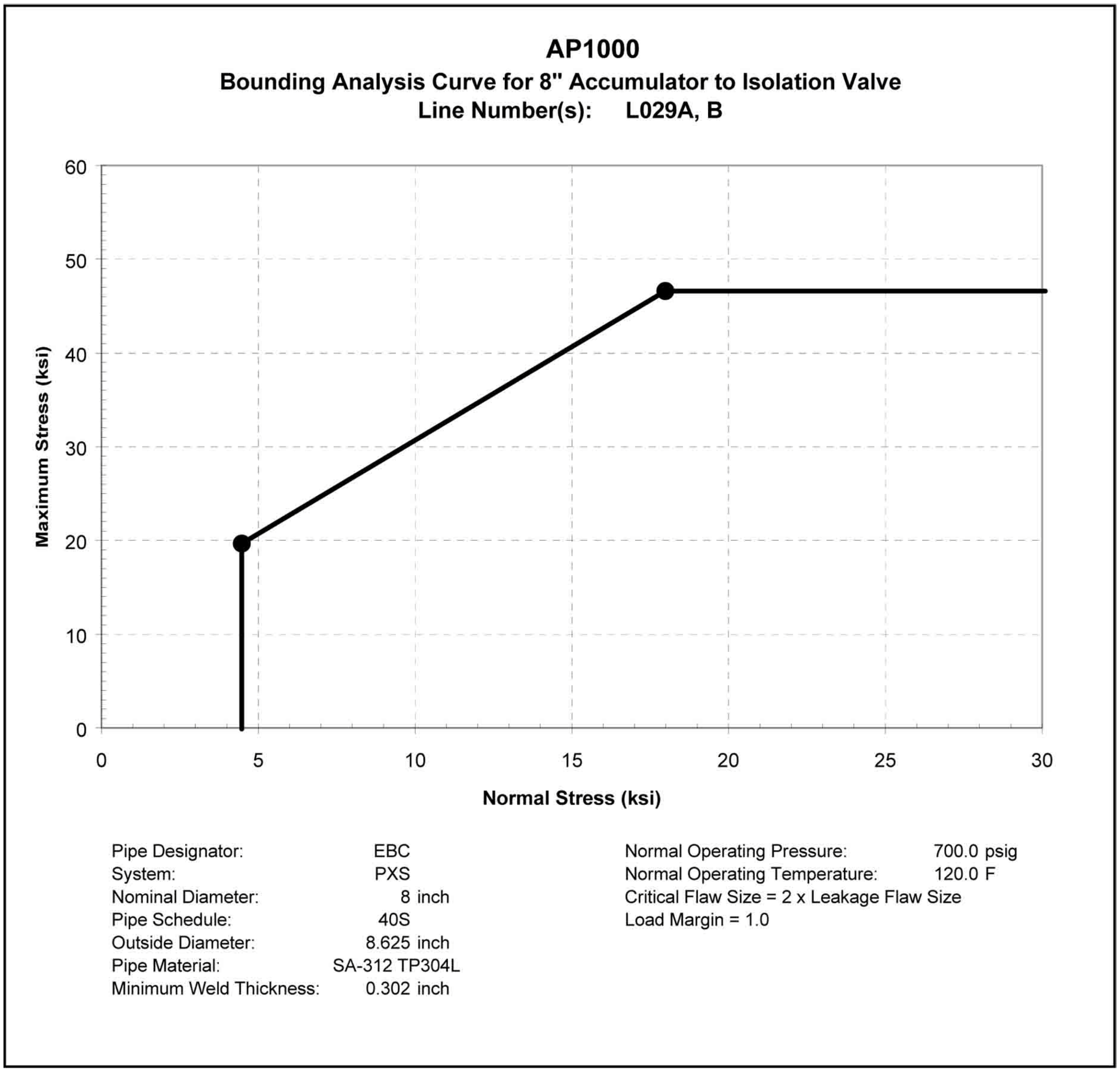


Figure 3B-13 Bounding Analysis Curve for 8″ Accumulator to Isolation Valve

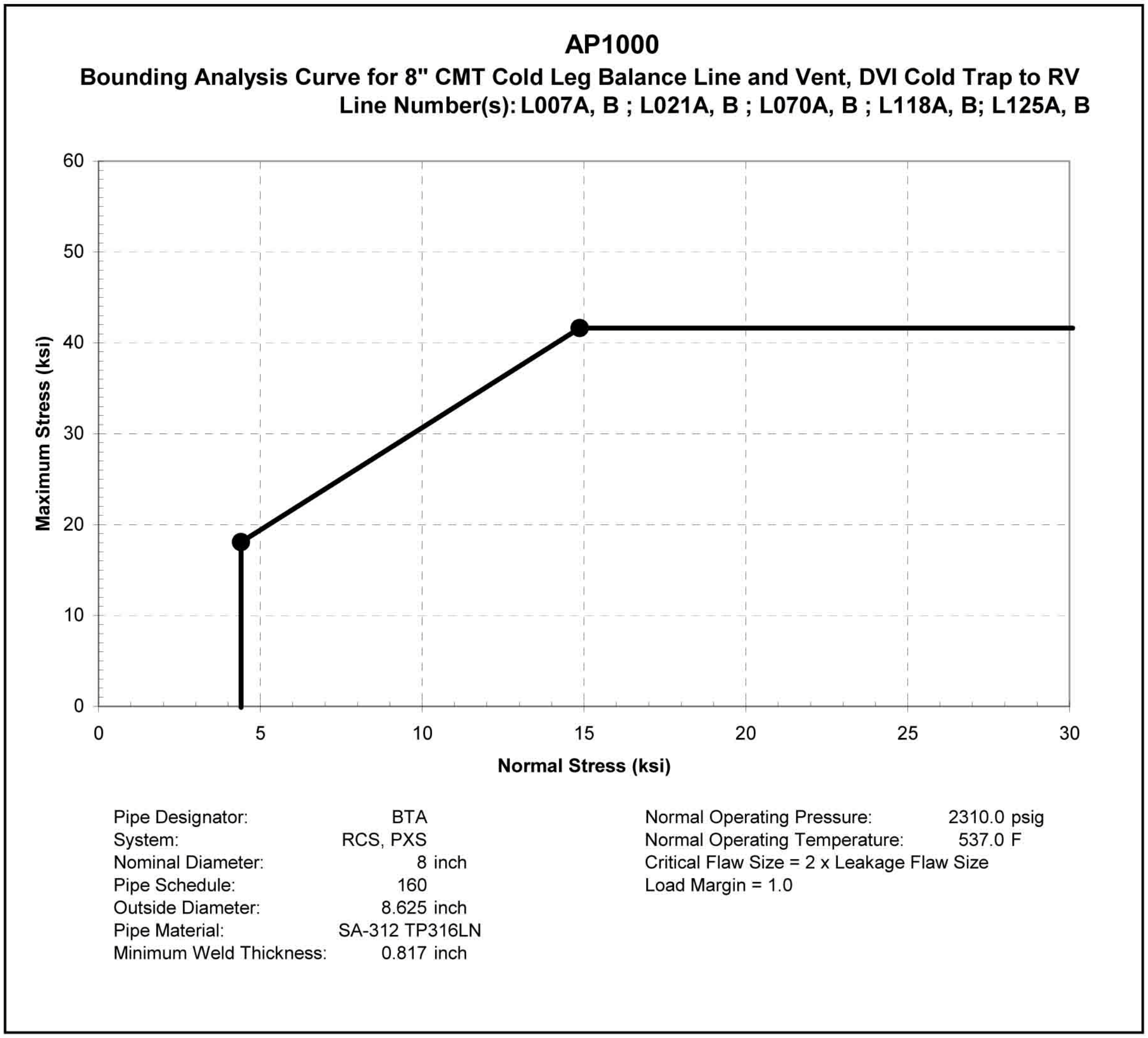


Figure 3B-14 Bounding Analysis Curve for 8″ CMT Cold Leg Balance Line and Vent, DVI Cold Trap to RV

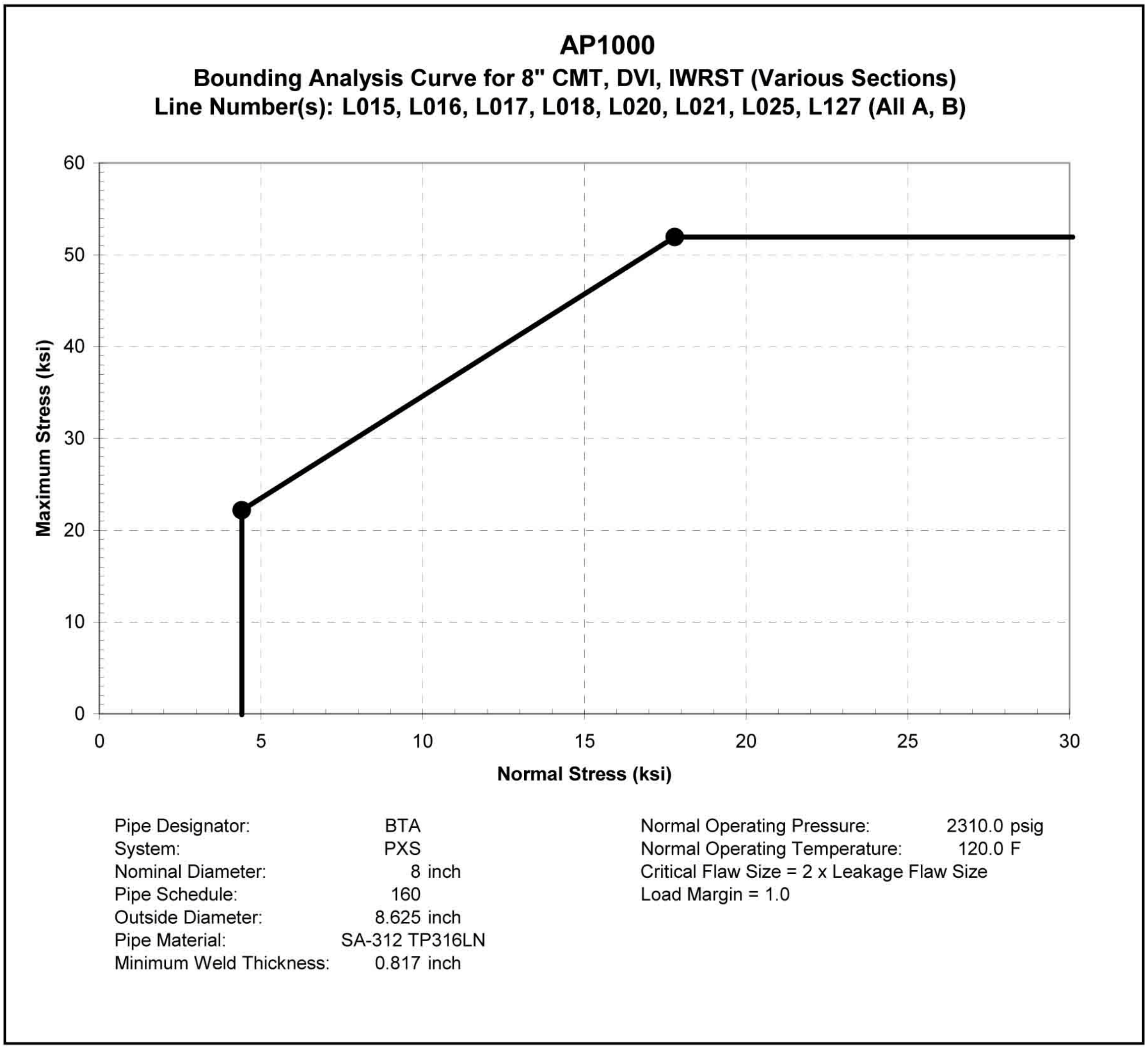


Figure 3B-15 Bounding Analysis Curve for 8″ CMT, DVI IWRST (Various Sections)

Figure 3B-16 not used.

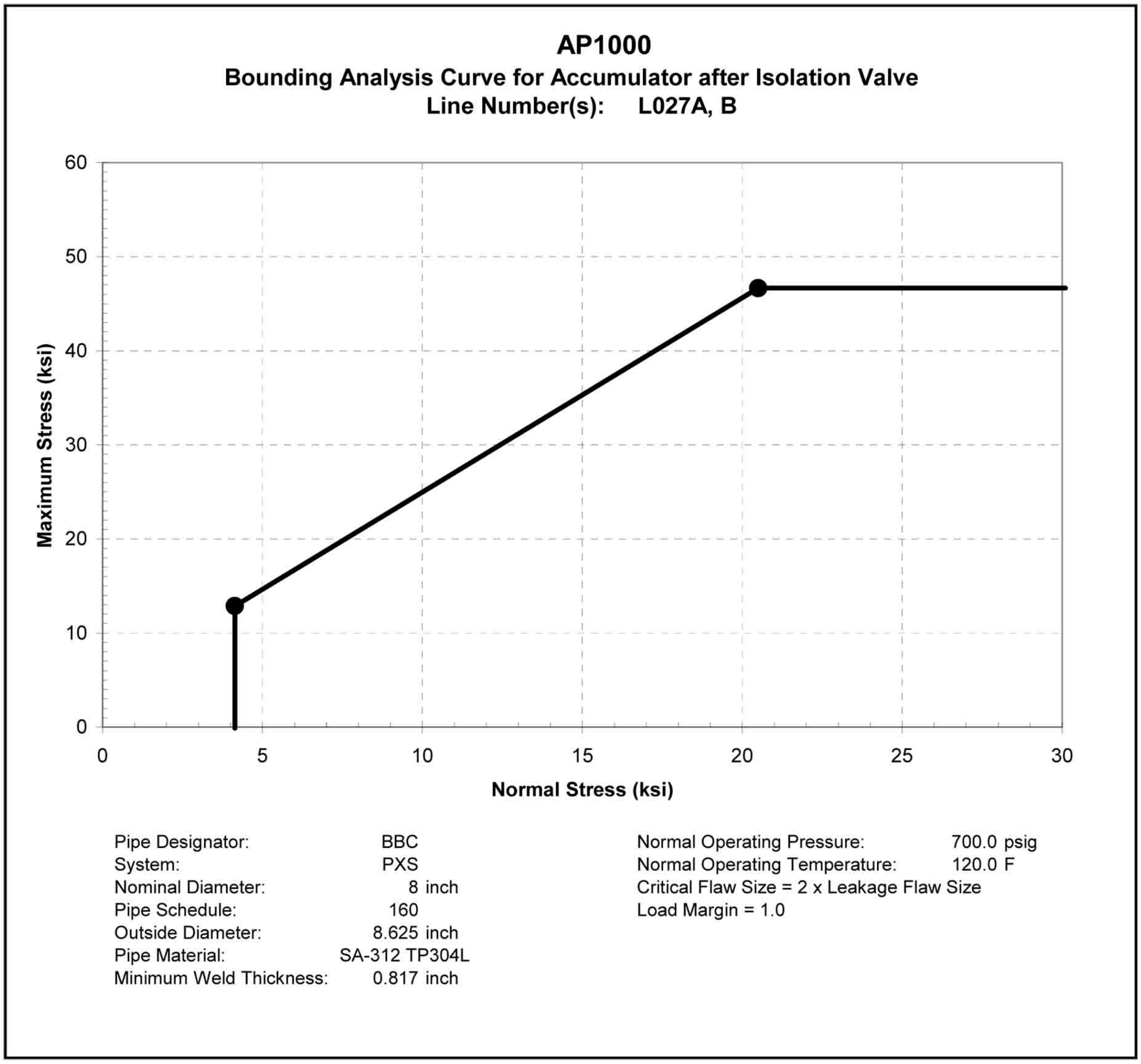


Figure 3B-17 Bounding Analysis Curve for Accumulator after Isolation Valve

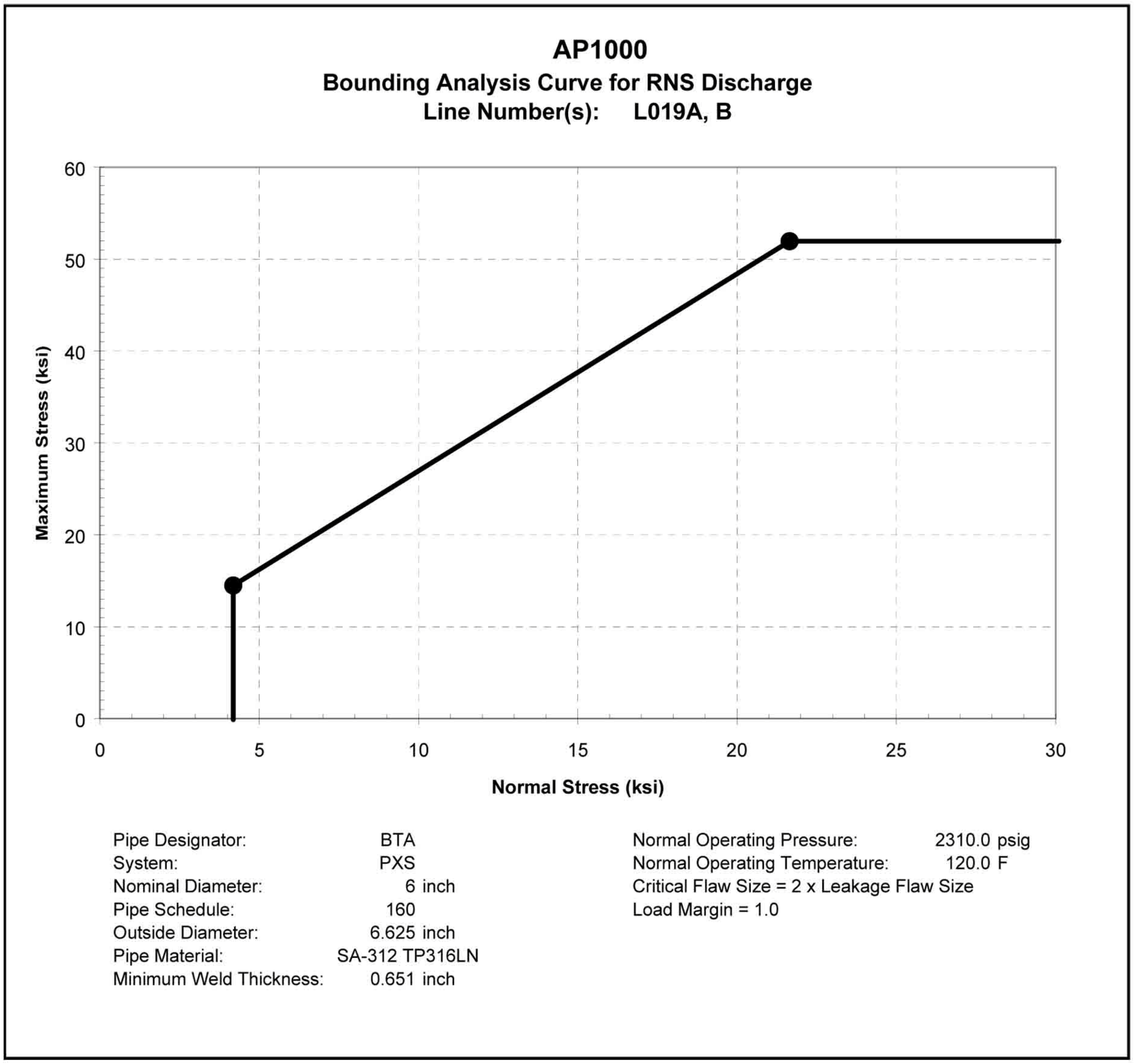


Figure 3B-18 Bounding Analysis Curve for RNS Discharge

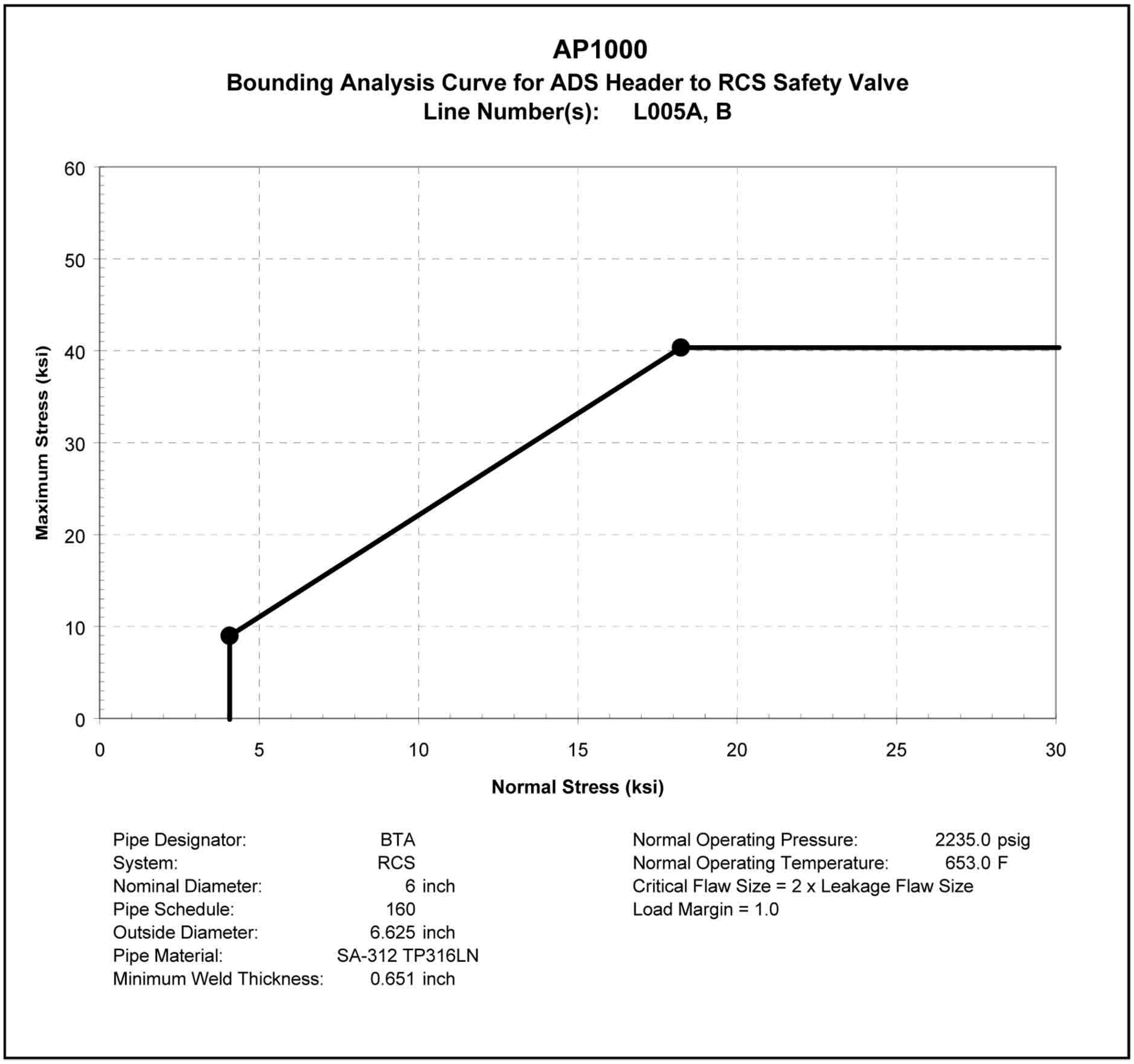


Figure 3B-19 Bounding Analysis Curve for ADS Header to RCS Safety Valve

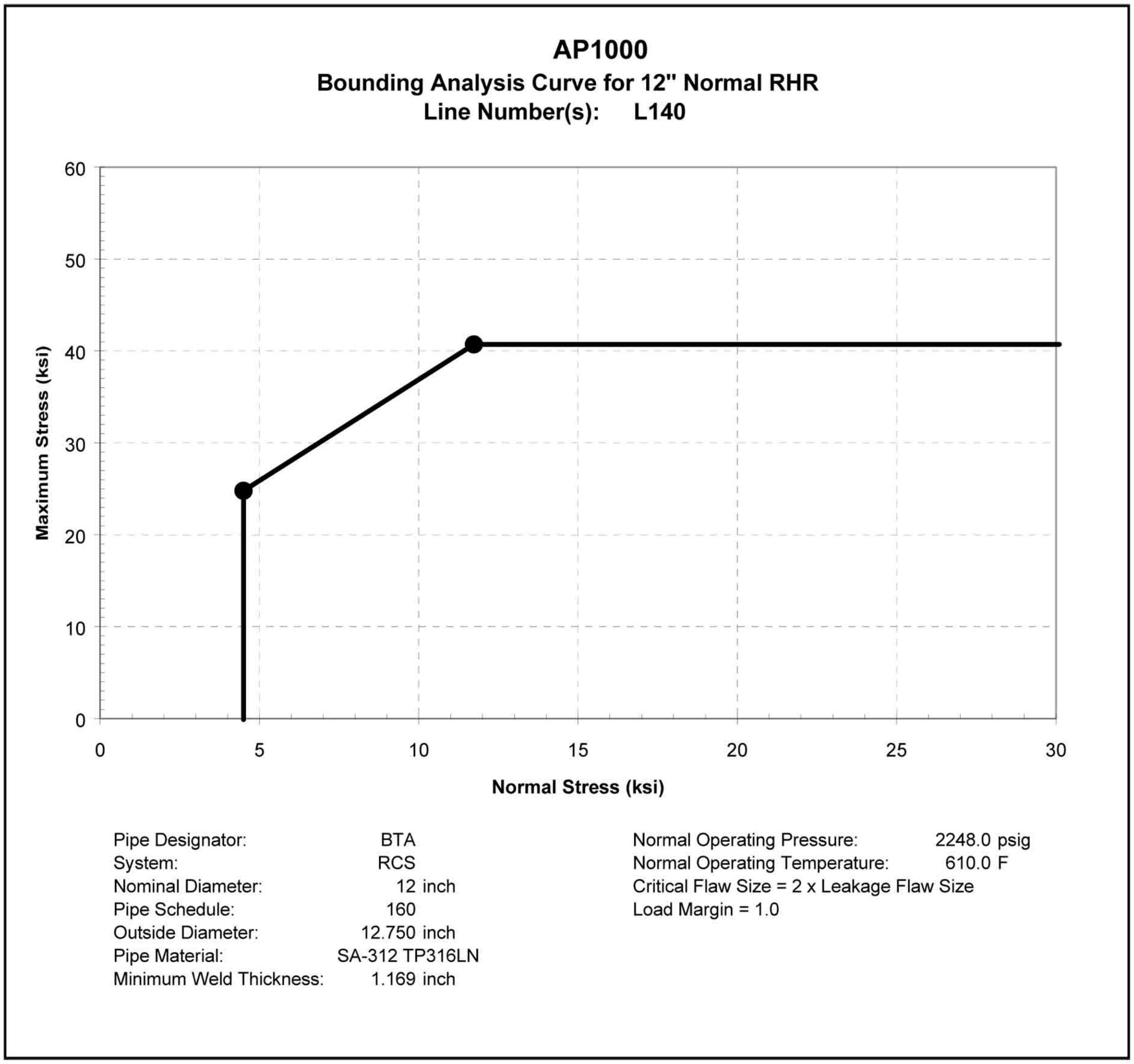


Figure 3B-20 Bounding Analysis Curve for 12″ Normal RHR

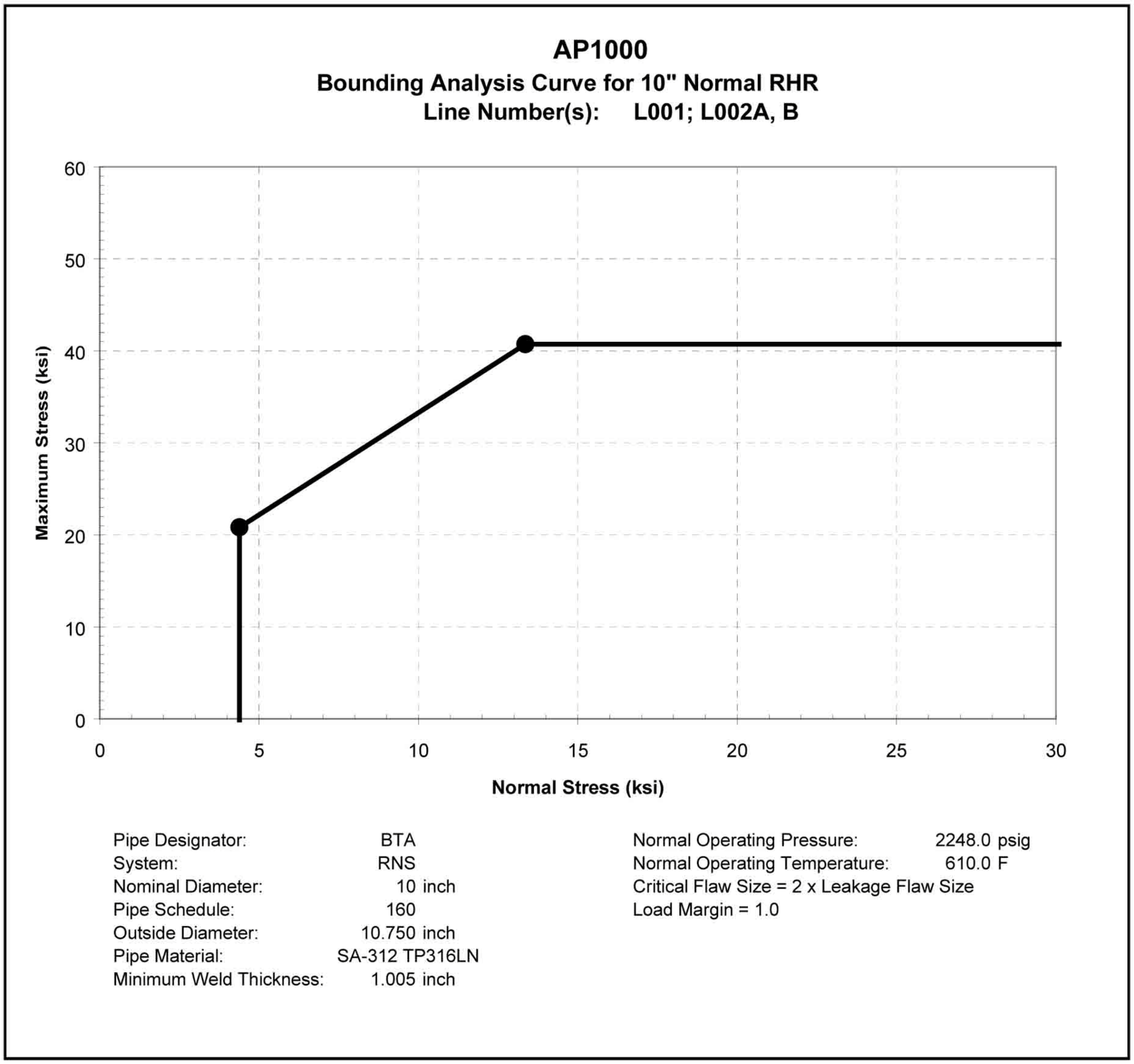
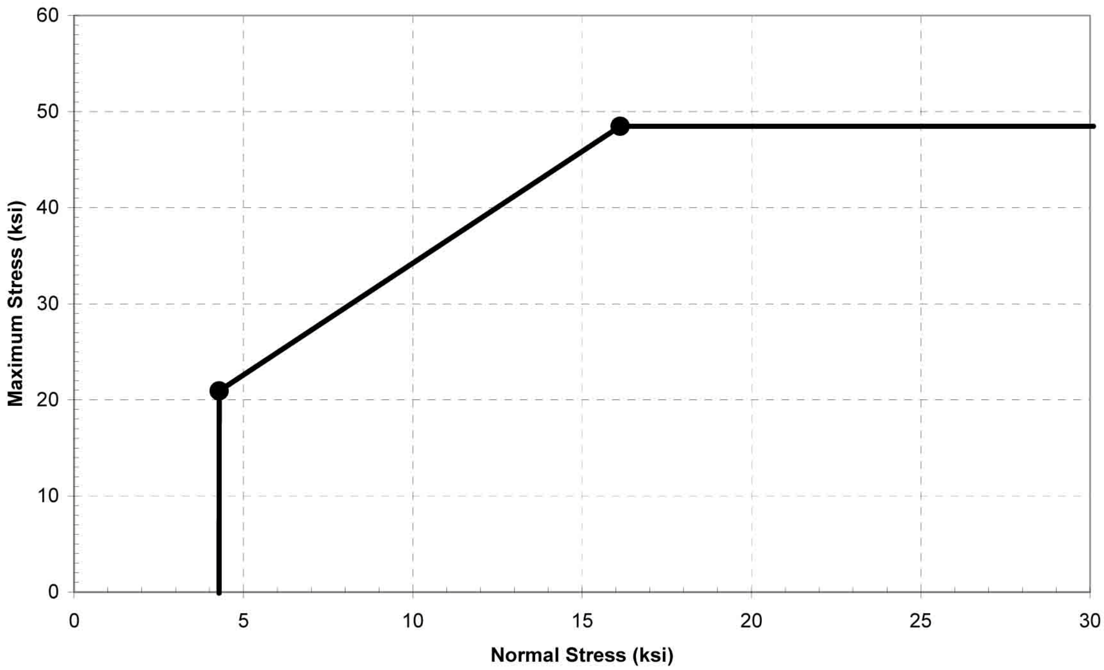


Figure 3B-21 Bounding Analysis Curve for 10″ Normal RHR

AP1000
Bounding Analysis Curve for 8" ADS Stage 2, 3
Line Number(s): L021A,B ; L031A,B



Pipe Designator:	BTA
System:	RCS
Nominal Diameter:	8 inch
Pipe Schedule:	160
Outside Diameter:	8.625 inch
Pipe Material:	SA-312 TP316LN
Minimum Weld Thickness:	0.817 inch

Normal Operating Pressure:	2235.0 psig
Normal Operating Temperature:	250.0 F

Critical Flaw Size = 2 x Leakage Flaw Size
Load Margin = 1.0

Figure 3B-22 Bounding Analysis Curve for 8″ ADS Stage 2, 3