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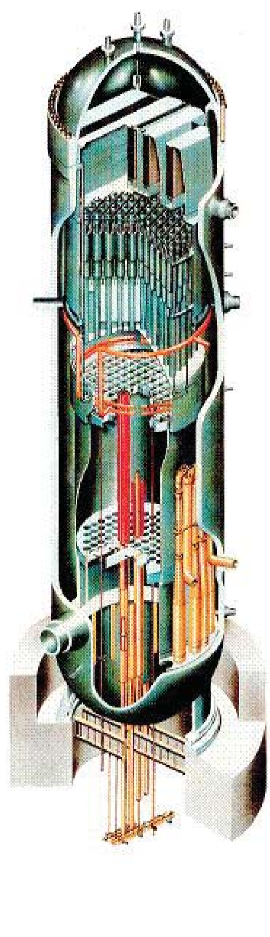
BWRVIP-192: BWR Vessel and Internals Project BWR System Pressure Test Limitations



BWRVIP-192: BWR Vessel and Internals Project

BWR System Pressure Test Limitations

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Technical Report, June 2008

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REPORT SUMMARY

This report examines the issues and limitations on performing the BWR pressure test at high temperatures and discusses options for managing the issue.

Background

The system pressure and leakage test must be performed at pressures and temperatures defined by the ASME Section XI, Appendix G method. In some cases, BWR plants may have to perform the system pressure test at elevated temperatures (exceeding 212°F) in order to maintain the ASME Code safety margins for prevention of vessel brittle fracture. Performing the pressure test at such high temperatures may be difficult and could pose additional safety concerns for workers inside the containment.

Objectives

- To examine the issues and limitations on performing the BWR pressure test at temperatures exceeding 212°F
- To understand the real limitations to perform the pressure test at higher temperatures in BWRs
- To consider plant-specific or generic options for managing the pressure test issue.

Approach

The project team reviewed the prior ASME Code changes that provided direct relief to the BWRs for performing the pressure test. These included ASME Code Case N-640 for use of the K_{IC} reference toughness curve to reduce hydrotest temperatures and Code Cases N-416 and N-498 for reduced hydrotest pressures. These Code Cases have now been codified and approved for use by NRC. The review also included several NUREG reports that gave utilities more options for dealing with the BWR system pressure test and hydrotest issue by allowing for improved Technical Specifications. The project team surveyed a number of BWR utilities to understand how these improvements have already been implemented to overcome the system pressure test limitations. Aside from administrative limits on the pressure test temperature that may be overcome by implementing the Code changes and improved Technical Specifications, there are other hardships, personnel risks, or economic considerations that may dictate the highest temperature that the system pressure test could be performed for a specific BWR plant. This study considered options available to utilities facing increases in the pressure test temperature due to extended plant life or higher projected levels of radiation embrittlement of the vessel beltline materials.

Results

The results of the evaluation suggest that pressure tests at higher temperatures (exceeding 212°F) can be performed in BWRs and there are no inherent difficulties that cannot be overcome using available technology. However, there are some additional costs associated with performing system pressure tests at a higher temperature as well as a recognized risk of exposure to plant personnel. One option for improving this situation is the use of a risk-informed approach for developing P-T limit curves, including an alternative method for calculating the system pressure test curve limits that would reduce the pressure test temperature. This risk-informed approach is several years from completion and approval by the ASME Code, but it may offer the best option for managing the difficulties associated with the increasing pressure test temperatures in BWRs. Another possibility may be to justify the use of a smaller reference flaw size for the ASME Section XI, Appendix G analysis. Both options would help reduce the pressure test temperature to manageable levels while assuring sufficient fracture margins.

EPRI Perspective

EPRI has funded several proof-of-concept studies to determine the best approach to apply risk-informed methods for defining P-T limits and pressure test temperatures. Additional work is continuing to develop the risk-informed methodologies for improved P-T limits. The EPRI studies are being performed now so that more options will be available for BWRs before the increases in pressure test temperatures start to become significant hardships.

Keywords

Reactor pressure vessel integrity
ASME Code, Appendix G
Pressure testing
Reactor vessel embrittlement
Boiling water reactor
Pressure-temperature limits
Technical specifications

ACKNOWLEDGEMENTS

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1 INTRODUCTION

The ability to perform the Boiling Water Reactor (BWR) system pressure test and meet the ASME Code margins is one of the conditions that must be evaluated for plants when revising the pressure-temperature (P-T) limit curves. In some cases, plants may have to perform the system pressure test at temperatures exceeding 212°F (i.e., boiling at atmospheric pressure) in order to maintain the ASME Code safety margins for prevention of vessel brittle fracture. Performing the pressure test at such high temperatures is very difficult and could pose safety concerns for workers looking for leakage inside the containment. This study examines the issues and limitations on performing the pressure test at high temperatures and discusses options for managing the BWR pressure test issue.

1.1 Implementation Requirements

This report is provided for information only. Therefore, the implementation requirements of Nuclear Energy Institute (NEI) 03-08, Guideline for the Management of Materials Issues, are not applicable.

2 BACKGROUND

Class 1 nuclear systems must undergo periodic system pressure and associated leakage tests, in order to demonstrate system integrity and leak tightness. Limitations on BWR system pressure test conditions were a concern in the 1980's when Regulatory Guide 1.99, Revision 2 [1] was implemented by the NRC. At that time, and with the higher predicted RT_{NDT} shifts under Regulatory Guide 1.99, Rev. 2 for the limiting vessel beltline materials, the required temperature for system pressure tests in many cases exceeded 212°F. This temperature posed significant operational problems for utilities in performing those tests. A survey performed by the BWR Owners Group (BWROG) in 1986 characterized the difficulties in performing the pressure test at higher temperatures [2]. Fortunately, changes to the ASME Code and NRC regulations in the 1990s provided some relief. However, the potential for further increases in the pressure test temperatures for BWRs raises many of the same concerns that were identified previously in the BWROG survey.

The potential impact on BWR operations derives from three factors: 1) visual inspection for leaks during the pressure test at temperatures exceeding 212°F is difficult inside the drywell and extremely difficult and time consuming at other locations; inspections for leakage under these adverse circumstances makes them less effective and less reliable; 2) residual decay heat and pump heat is used to raise the temperature, and the rate of increase in temperature is only a few degrees per hour at the higher temperatures; therefore, system pressure and leakage testing is likely to be performed on the critical path for restart, which prolongs the outage and results in lost power production with its associated cost; and 3) many plant Technical Specifications require that the drywell head must be in place, the containment closed and the safety systems operable when coolant temperature exceeds 200°F. Therefore, the pressure test must be done at the end of the outage when the time to run the test and the time to correct any observed leakage also adds to the outage time and cost.

In order to address the issue of elevated temperature pressure testing, BWR pressure test limitations in operating plants were again reviewed and evaluated based on the current plant conditions. This recent evaluation was conducted to understand whether BWR plants have made adjustments that would allow the system pressure test to be performed at temperatures exceeding 212°F. In particular, the current review asked the following questions in interviews with a number of utility personnel:

1. What is the maximum temperature at which the pressure test could be performed in BWRs while assuring reliable inspections for leaks?
2. Are there additional risks, costs, or safety concerns for having to perform the system pressure test at temperatures above 212°F?

3. What are the additional difficulties in performing the pressure test at temperatures above 212°F?

The main issue for BWR plants is the ability to perform the system pressure test at higher temperatures without causing additional risks to the public and plant personnel, and without causing major costs or delays in the plant outage schedule. Changes to the ASME Code Section XI, Appendix G [3] and Subsection IWA-5000 criteria [4] have relieved some of the restrictions to performing the pressure test. However, the issue of increasing pressure test temperatures is becoming a concern again.

Several options for managing or resolving the BWR pressure test limitation issue were developed previously, including changes to the ASME Code and to the NRC regulations for performing hydrostatic pressure tests. These changes have relieved some of the restrictions to performing the pressure test and have reduced the hardships associated with the test by effectively minimizing the temperature increase associated with Revision 2 to Regulatory Guide 1.99. Most of the BWR plants have implemented these changes in their operating procedures in order to obtain relief.

In the future, BWR plants may need additional relief from pressure test temperatures that are too high. The methods or approaches that may be used to address this issue are described in this report, along with recommendations for plants that may be affected by significant increases in the temperature to perform the system pressure test.

3
REVIEW OF BWR PRESSURE TEST ISSUE

3.1 History of BWR Owners' Group Efforts on the Pressure Test Issue

In May 1988, the NRC issued Revision 2 to Regulatory Guide 1.99, "Radiation Embrittlement of Reactor Vessel Materials" [1]. This change in the Regulatory Guide caused an increase in the calculated adjusted reference temperature (ART) for many BWRs, because of the revised trend curve formula for embrittlement based on combined copper and nickel content and fluence. This increase in ART required a corresponding increase in the plant pressure test temperature, as shown in Figure 3-1. As shown in the figure, this increase was of the order of 90°F. As a result, many BWR plants were facing a significant hardship in the ability to perform the ASME Code Section XI pressure and leak tests at the temperature required to meet the ASME Section XI, Appendix G margins for prevention of brittle fracture of the vessel.

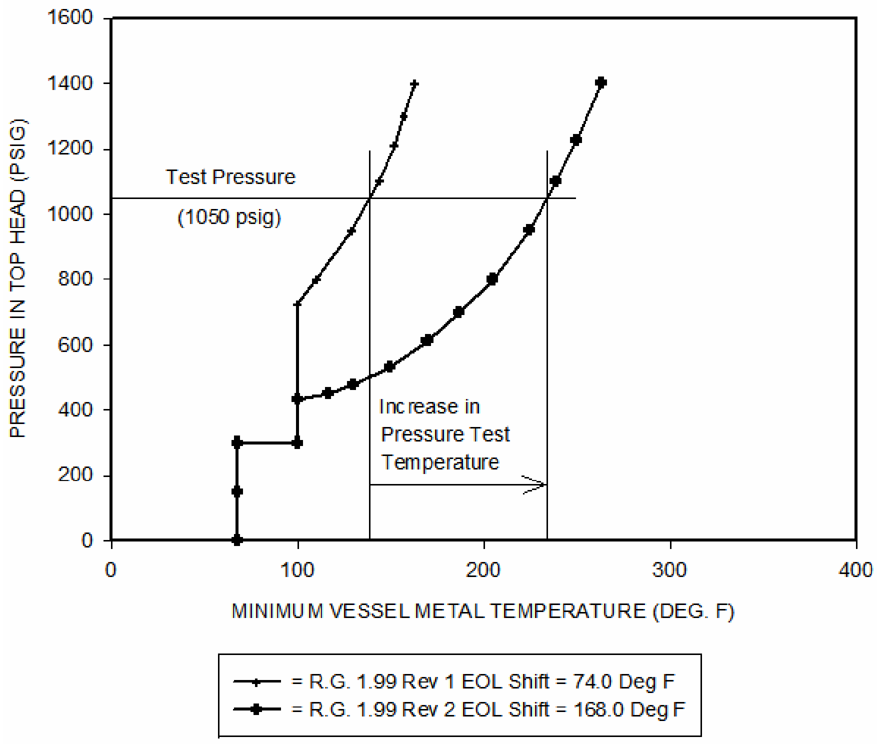

Figure 3-1
Example of a BWR Pressure Test Curve Categorized as "Changed"

Prior to the publication of Revision 2 of Regulatory Guide 1.99, the requirements to perform the pressure test could be met without exceeding the Mode 3 (Cold Shutdown) limit of approximately 200°F for all BWRs. After the implementation of Regulatory Guide 1.99, Rev. 2, the pressure test temperatures for a few plants exceeded 212°F, and many more plants were projected to exceed this test temperature prior to their end-of-license date. This created regulatory difficulties related to containment integrity and ECCS operability for those plants, and it resulted in a major effort by the BWROG to develop a generic resolution for the affected plants. The results of the BWROG evaluation are described in Reference [2]. The key objectives of the BWROG Pressure Test Group and the results of the evaluation are summarized below.

3.1.1 Impact of RG 1.99 Rev. 2 on Pressure Test Temperatures

A key objective of the BWROG effort at that time was to determine the impact on hydrostatic pressure test temperatures due to the increased RT_{NDT} shift and higher ART values resulting from implementation of RG 1.99 Rev. 2.

The results of the evaluation of the impact of RG 1.99 Rev. 2 showed that the pressure test temperatures (based on using Section XI, Appendix G with K_{Ia} reference toughness) at the end of the 40-year design life exceeded 200°F in 19 out of 35 BWRs evaluated. This indicated that the impact of the change in the predictive model (from RG 1.99 Rev. 1 to Rev. 2) was significant.

3.1.2 Operational Concerns Resulting from the Higher Pressure Test Temperatures

An important part of the BWROG activity was to document the operational concerns and personnel hardships related to the higher temperature pressure tests. In order to assess the operational issues, a questionnaire was sent to operating US BWRs. The questions and the responses are described in this section.

The operational concerns identified in [2] were based on answers from BWR plants on a questionnaire on system pressure test operating procedures. The list included questions such as: Is a system pressure test above 200°F possible? Can the system be heated to temperatures above 200°F with only decay heat and/or pump heat? What are the operational problems associated with pressure tests above 200°F? Can the impact of the pressure tests under ‘hot shutdown or startup conditions’ be quantified in terms of cost, time, and personnel safety? Similar questions were also asked about a pressure test at 220°F. Other questions included the feasibility of using nuclear heating and the potential for the use of auxiliary heaters.

The first set of questions addressed the operational issues arising from a 200°F pressure test. Responses were received from 15 plants. The following summarizes the responses:

a. 12 out of 15 plants said that a 200°F test was possible but difficult. The three plants which felt that the hot shutdown or startup test was not possible concluded that restrictive plant technical specification requirements were the reason. The operational problems included the possibility of pump cavitation; in order to avoid cavitation conditions, additional pressurization of the system may be required.
b. Since pump heat is needed to achieve the higher temperatures, the time required to achieve the required temperature was 12 - 48 hours, which added directly to the outage critical path.
c. Increased pump operation time, especially at lower pressures, may cause premature seal failure.
d. There is higher risk of burns for inspection personnel during the leakage examinations.
e. The inspection for leaks is less reliable if the pressure test temperature exceeds 212°F and leakage is in the form of steam.
f. The incremental cost (compared to cold shutdown pressure test) ranged from $100K - $400K per test, based on replacement power costs in 1986 dollars.

Similar problems were cited in response to questions related to the 220°F pressure tests, except that the severity was higher. The following summarizes the specific responses:

a. Seven out of 15 plants felt that a 220°F test was not possible, again due to technical specification requirements. The time required to achieve the required temperature was higher for the 220°F test, ranging from 12 - 96 hours.
b. A more significant operational problem for tests in excess of 212°F was that primary containment isolation was required, which meant that almost no work could be performed in parallel in the containment. This made the pressure test a critical path event in the outage.
c. Other operational problems included the requirement that ECCS and other safety systems be operational during the test.
d. There was also the concern that operational safety relief valves may lift during hydrostatic pressurization.
e. The most significant concern was that leak detection would be difficult and dangerous because the leakage would be steam; burn risks to personnel would be greater and more radiation gear may be required.
f. The incremental cost (compared to a cold shutdown pressure test) ranged from $150K - $1,330K more per test based on replacement costs in 1986 dollars, although the upper range of these costs may be very conservative.

The nuclear heat option was judged to be possible only by 3 out of 15 plants. In large part, the technical specification requirements were the primary reasons for inability to perform the system pressure test using nuclear heating.

3.1.3 Alternatives to Appendix G for Determining Pressure Test Temperature

A key task in the generic BWROG effort to resolve the issue was to suggest alternatives to ASME Section XI, Appendix G that would result in reducing the impact of RG 1.99 Rev. 2 on pressure test temperatures. The alternatives that were proposed are summarized here:

Change in the Postulated Flaw Size: This proposal allowed the use of a smaller postulated flaw size for hydrostatic pressure tests when the core is not critical. The factor of 1.5 on K_{Ia} would still be maintained. There is precedent for this in that smaller postulated flaws are allowed as long as the inspection methods are qualified (e.g. smaller flaws are postulated in the vessel and vessel head flange region). Appendix K also allows smaller postulated flaws (1 inch instead of the typical ¼ T or 1.5 inches). Use of a one-inch flaw would result in a reduction of 20°F when compared to that for a ¼ T flaw.

Pressure Test Based on K_{Ic}: The use of K_{Ic} instead of K_{Ia} reference toughness curve can provide a significant reduction in the pressure test temperature. Typically, the use of K_{Ic} results in a reduction of 50°F in the pressure test temperature.

Use of ART_{NDT} + 60°F as an Upper Limit for the Pressure Test: The ASME Section XI, Appendix G procedure with the ¼ T flaw and K_{Ia} would still be maintained, but the maximum test temperature would not exceed ART_{NDT} + 60°F. This results in a reduction of 40° - 50°F in the pressure test temperature.

Use of the Appropriate Stress Level for the Postulated Flaw in a Weld Seam: Unlike the procedure (at that time) which required the use of the circumferential stress and axially oriented reference flaw regardless of whether the weld is circumferentially or axially oriented, this concept would allow the use of the axial stress for a postulated flaw in the circumferential weld. While this does not solve the problem on a generic basis, there may be relief in some cases where the circumferential weld chemistry is controlling.

3.1.4 NRC Position on the BWROG Proposals

The NRC did not approve the BWROG proposal, citing the concern that there was not enough surveillance test data to provide confidence that the proposed relief concepts would not reduce the fracture margins to unacceptable levels. As described later, the NRC and the ASME Code did approve one of the suggested alternatives in the BWROG program (i.e., pressure test based on use of the K_{IC} reference toughness) later in February 1999. However, in the process of resolving this issue, several plants were prohibited from using nuclear heat to heat the primary coolant to the required elevated test temperature. This caused additional burdens for plants trying to maintain the ASME Code margins while performing the pressure test.

3.2 Subsequent ASME Code Actions to Provide Relief on the BWR Pressure Test Temperature Issue

Eventually, the ASME Code implemented several changes that provided direct relief to the BWRs for performing the pressure test. The specific ASME Code changes that were credited by those plants with BWR pressure test limitations included:

- ASME Code Case N-640 [5] for use of the K_{IC} reference toughness curve to reduce pressure test temperatures; and
- Code Cases N-416 [6] and N-498 [7] for reduced system leak test pressures

NRC also issued several NUREGs that gave utilities more options for dealing with the BWR pressure test issue by allowing for improved Technical Specifications. These included:

- Standard Technical Specifications, General Electric Plants, BWR/4 [8]; and
- Standard Technical Specifications, General Electric Plants, BWR/6 [9]

Currently, all BWRs are using a combination of the above methods to achieve reductions in the temperature and pressure required to perform the system pressure and associated leak test. Other options have been examined for developing an alternative ASME Code Section XI type criterion for determining BWR pressure test temperatures based on probabilistic fracture mechanics; however, these methods have not yet been accepted by the ASME Code.

3.3 ASME Code Cases N-640 for Alternative Reference Toughness

In 1998, the ASME Section XI Working Group on Operating Plant Criteria developed Code Case N-640 that permitted the alternative use of the K_{IC} reference toughness curve for P-T limits and pressure test temperatures. This Code Case, which eventually was incorporated into the body of the ASME Code, was initially proposed by the BWROG as a solution to resolve the BWR pressure test temperature issue in 1987, but it was rejected by the NRC staff at that time. After Code Case N-640 was finally approved and published in February 1999, the NRC began to accept relief requests by BWR owners early in 2000 to use the Code Case. The benefit to the BWR plants was an immediate reduction in the pressure test temperature of approximately 50°F (as shown in Figure 3-2) and a critical path time reduction as much as 20 – 28 hours.

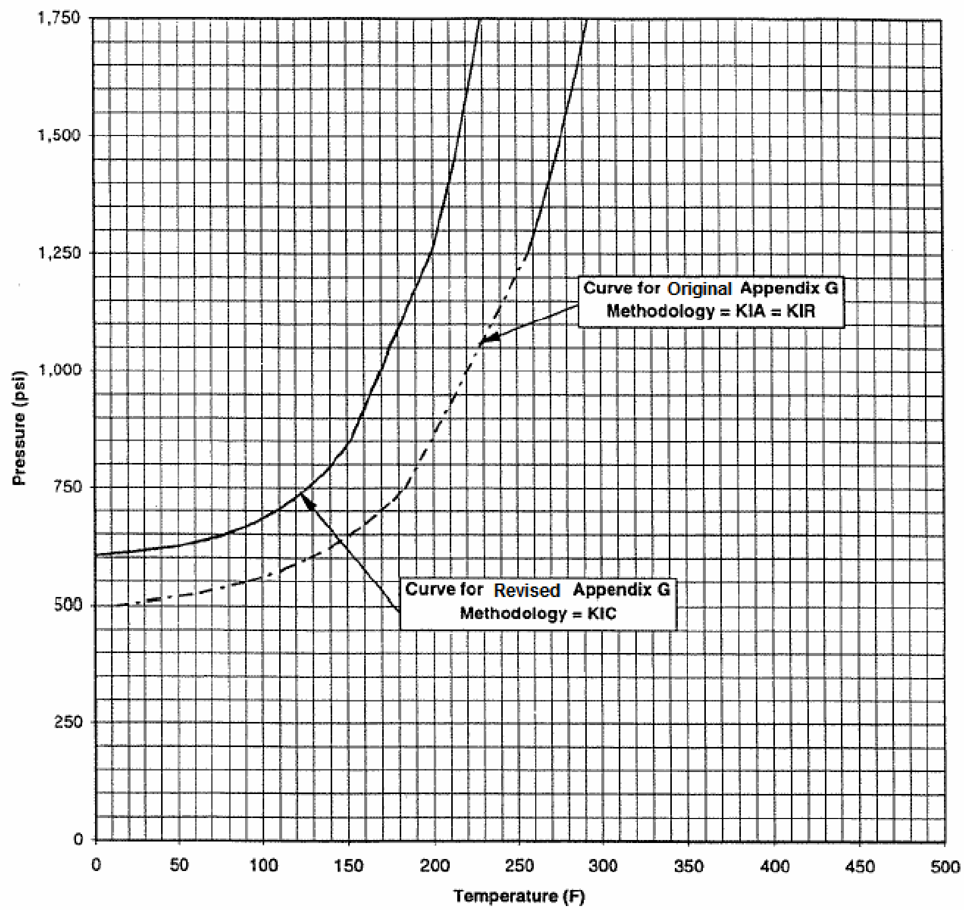

Figure 3-2
Comparison of BWR Pressure Test P-T Curves Using the Original (K_{IA}) and Revised (K_{IC}) ASME Code Reference Toughness Curves

3.4 Code Case N-416 and Code Case N-498 for Pressure Testing

The ASME Code requirements for Class 1 component system pressure tests are found in two locations – the generic requirements in IWA-5000 that apply to all component classes and the requirements in IWB-5000 that apply only to Class 1 components. IWA-5200 distinguishes between test conditions for the system leakage test of IWA-5211(a) and the system hydrostatic test of IWA-5211(b).

Until the mid-1980s, there were several types of pressure tests defined in the ASME Code: a pre-service hydrostatic pressure test at a pressure 125% of the design pressure (times the ratio of the stresses) performed once before the plant is placed into service; a system leakage test conducted at a nominal operating pressure and temperature; and a system hydrostatic test performed at a pressure 110% of the normal operating pressure. The temperature at which the tests are to be conducted must be in accordance with the safety margins defined in ASME Section XI, Appendix G [3].

In the 1980s and 1990s, there were some significant changes made to the ASME Code for performing the system hydrostatic and pressure tests. For example, Code Case N-416, published in 1985, permitted a deferral of the Class 2 system hydrostatic test following repair/replacement activity to the next 10-year hydrostatic test to be performed at the end of each inspection interval. This deferral was justified by performance of a system leakage test at operating pressure following the repair/replacement activity and before plant startup. The basis for this Code Case is that the difference in pressure between the leak test and the hydrotest does not provide sufficient benefits to warrant the difficulty of applying the higher test pressure (and temperature).

Similarly, Code Case N-498, which was approved by the ASME Code in 1991, extended the idea of the near-equivalence of system leakage tests to hydrotests. This Code Case allowed the substitution of system leakage tests for the 10-year hydrostatic pressure tests. The original version of Code Case N-498 was only applicable to Class 1 and 2 systems. A revision of the Code Case around 1994, Case N-498-1, permitted the substitution of system leakage tests for hydrostatic pressure tests in Class 3 systems.

Subsequently, Code Case N-416 was also revised (N-416-1) to eliminate the 110% hydrostatic testing completely for repair/replacement activities for Class 1, 2, and 3 systems. These Code Cases were granted regulatory acceptance under Regulatory Guide 1.147 [13]. The provisions of these Code Cases have now been incorporated into the ASME Code Section XI, Article IWA-4540 (Repair/Replacement Activities) [10] and IWA-5000 (System Pressure Tests) [4]. The corresponding Code Section IWA-5212(f) permits the system hydrostatic test and associated visual examination to replace the system leakage test and associated visual examination. IWB-5220 describes the system leakage test for Class 1 components, while IWB-5230 describes hydrostatic test requirements. The BWR utilities are using these Code provisions to eliminate all system hydrostatic testing at 110% of the operating pressure. Only a leakage test at operating pressure is required after each refueling outage in a BWR, although a leakage test with an extended pressurization boundary is required once every 10 years.

The ASME Code currently provides some additional measure of relief from the visual examination conditions associated with the system pressure (leakage) test in IWA-5245. That paragraph points out that visual examination of system components requiring a test temperature above 200°F (95°C) during the system pressure test may be conducted after the pressure holding period of IWA-5213 has been satisfied, and the pressure has been lowered to a level corresponding with a temperature of 200°F (95°C). In other words, the visual examination may be conducted at a temperature of 200°F (95°C), even though the system pressure test temperature may be considerably higher, provided that the holding period for the system pressure test has been met, and the potential for leakage from system pressure and temperature during that holding period has occurred. In such a case, both evidence of leakage from the higher pressure and temperature, as well as any continuing leakage at the lower pressure and temperature should be part of the visual examination. However, many utilities believe it is not practical to hold the system at a higher temperature and then reduce the temperature in order to perform the leakage inspection.

3.5 Technical Specification Improvements

The U. S. Nuclear Regulatory Commission (NRC) has made provisions for plants to better manage plant operations through standardized and improved Technical Specifications. For example, NUREG-1433 [8] and NUREG-1434 [9] were issued as Standardized Technical Specifications for BWR plants. These guidelines for improved Technical Specifications were published to achieve some consistency throughout the industry to manage risk. One method for accommodating the increased hydrostatic and leakage test temperature requirements, while continuing to essentially maintain existing procedures, is to implement a Limiting Condition of Operation (LCO) through the Technical Specification improvement process. The NRC staff have provided, and continue to provide – through periodic updates – a Limited Condition of Operation (LCO) mechanism for allowing BWR hydrostatic pressure testing, and associated in-service leakage test visual examinations, when the adjusted reference temperature of the reactor pressure vessel requires the pressure testing to be performed at temperatures > 200°F [8, 9]. This mechanism is based on revisions to Standard Technical Specifications by the affected nuclear power plant, through Section B 3.10, Special Operations, and, in particular, B 3.10.1, Inservice Leak and Hydrostatic Testing Operation.

A number of BWR/4 plants and BWR/6 plants have taken advantage of the NRC staff evaluation and analyses that are included in References [8] and [9], especially the Background and Bases sections of those references. (The BWR/5 plants use a hybrid combination of the BWR/4 and BWR/6 Standard Technical Specifications.)

For example, NUREG-1433, Section 3.10.1 for Special Operations of Inservice Leak and Hydrostatic Testing Operation, states [8]:

> "3.10 SPECIAL OPERATIONS
>
> LCO 3.10.1 The average reactor coolant temperature for MODE 4 may be changed to "NA", and operation considered not to be in MODE 3; and the requirements of LCO 3.4.9, "Residual Heat Removal (RHR) Shutdown Cooling System – Cold Shutdown," may be suspended, to allow performance of an inservice leak or hydrostatic test provided the following MODE 3 LCOs are met:
>
> a. LCO 3.3.6.2, "Secondary Containment Isolation Instrumentation," Functions [1, 3, 4, and 5] of Table 3.3.6.2-1,
>
> b. LCO 3.6.4.1, "Secondary Containment,"
>
> c. LCO 3.6.4.2, "Secondary Containment Isolation Valves (SCIVs)," and
>
> d. LCO 3.6.4.3, "Standby Gas Treatment (SGT) System."
>
> APPLICABILITY: MODE 4 with average reactor coolant temperature > 200°F."

The Background section in Reference [8] states that:

> "The purpose of this Special Operations LCO is to allow certain reactor coolant pressure tests to be performed in MODE 4 when the metallurgical characteristics of the reactor pressure vessel (RPV) require the pressure testing at temperatures > 200°F (normally corresponding to MODE 3).
>
> Inservice hydrostatic testing and system leakage pressure tests required by Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (Reference [1]) are performed prior to the reactor going critical after a refueling outage. Recirculation pump operation and a water solid RPV (except for an air bubble for pressure control) are used to achieve the necessary temperatures and pressures required for these tests. The minimum temperatures (at the required pressures) allowed for these tests are determined from the RPV pressure and temperature (P-T) limits required by LCO 3.4.10, "Reactor Coolant System (RCS) Pressure and Temperature (P-T) Limits." These limits are conservatively based on the fracture toughness of the reactor vessel, taking into account anticipated vessel neutron fluence.

With increased reactor vessel fluence over time, the minimum allowable vessel temperature increases at a given pressure. Periodic updates to the RPV P-T limit curves are performed as necessary, based upon the results of analyses of irradiated surveillance specimens removed from the vessel. Hydrostatic and leak testing will eventually be required with minimum reactor coolant temperatures > 200°F."

The Bases section states that:

"Allowing the reactor to be considered in MODE 4 during hydrostatic or leak testing, when the reactor coolant temperature is > 200°F, effectively provides an exemption to MODE 3 requirements, including OPERABILITY of primary containment and the full complement of redundant Emergency Core Cooling Systems. Since the hydrostatic or leak tests are performed nearly water solid, at low decay heat values, and near MODE 4 conditions, the stored energy in the reactor core will be very low. Under these conditions, the potential for failed fuel and a subsequent increase in coolant activity above the LCO 3.4.7, "RCS Specific Activity," limits are minimized. In addition, the secondary containment will be OPERABLE, in accordance with this Special Operations LCO, and will be capable of handling any airborne activity or steam leaks that could occur during the performance of hydrostatic or leak testing. The required pressure testing conditions provide adequate assurance that the consequences of a steam leak will be conservatively bounded by the consequences of the postulated main steam line break outside of primary containment described in *Reference 2*. Therefore, these requirements will conservatively limit radiation releases to the environment.

In the event of a large primary system leak, the reactor vessel would rapidly depressurize, allowing the low pressure core cooling systems to operate. The capability of the low pressure coolant injection and core spray subsystems, as required in MODE 4 by LCO 3.5.2, "ECCS – Shutdown," would be more than adequate to keep the core flooded under this low decay heat load condition. Small system leaks would be detected by leakage inspections before significant inventory loss occurred.

For the purposes of this test, the protection provided by normally required MODE 4 applicable LCOs, in addition to the secondary containment requirements required to be met by this Special Operations LCO, will ensure acceptable consequences during normal hydrostatic test conditions and during postulated accident conditions.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases."

This background information and elements of the Bases have been used by BWR/4 and BWR/6 plants to support the incorporation of the LCO into their individual plant Standard Technical Specifications.

It should be pointed out that the four Mode 3 LCOs that must be met in order to apply LCO 3.10.1 in Mode 4 are all related to control of potential radioactive material, in particular fission gases, by the secondary containment system in the event of a leak from primary containment during the hydrostatic and leakage testing exercise. LCO 3.3.6.2 concerns the functionality of the Secondary Containment Isolation Instrumentation while in Mode 4, which automatically closes the Secondary Containment Isolation Valves (SCIVs) and starts the Standby Gas Treatment (SGT) system. The function of the Secondary Containment (and the SCIVs) is to contain, dilute, and stop radioactivity that might leak from primary containment following a design-basis accident. The function of the two SGT trains is to ensure that any radioactive materials that might leak from the primary containment into the secondary containment following a design-basis accident are filtered and absorbed prior to exhausting to the environment. LCOs 3.6.4.1, 3.6.4.2, and 3.6.4.3 establish requirements for the operability of the Secondary Containment, the SCIVs, and the two SGT trains. Therefore, these four LCOs are intended to provide protection against a potential leak of radioactive material while the plant is in Mode 4 for the hydrostatic and leakage testing operation.

An example of the generic BWR Technical Specification for system pressure testing is shown in Appendix A, and an example of an improved Technical Specification to take credit for the provisions of the LCO for Special Operations is shown in Appendix B.

4
EVALUATION OF BWR PRESSURE TEST LIMITATIONS

4.1 Safety Significance of Increased Pressure Test Temperature

From the latest inquiries of plant owners, the maximum temperature to perform the BWR system pressure test was determined to be as high as 275°F to 300°F, depending on the plant. There is no fixed upper temperature limit if the LCO for Special Operations is used to increase the pressure test temperature above 212°F, although one BWR plant has increased the applicability to 300°F. The LCO for Special Operations allows the reactor to be considered to be in cold shutdown with reactor coolant temperature between 212°F and 300°F. Thus, the applicability of this improved Technical Specification is for Mode 4 with average reactor coolant temperature > 212°F.

The temperature allowance of up to 300°F is based on plant-specific analyses of secondary containment capability and may be different for other plants. Inservice leak and pressure tests are very controlled evolutions involving strict procedural compliance. The minimum temperatures (at the required pressures) allowed for these tests are determined from the plant P-T limits from Curve A for pressure tests. Operations must ensure that these minimum temperature conditions are met for the pressure test. However, the maximum temperature limitations are based on other considerations such as containment integrity or temperature drift. The specified upper limit on pressure test temperature determines how much flexibility the operators have to perform the test. The 300°F upper limit was chosen based on a conservative plant-specific analysis. The analysis postulated a recirculation line break and examined the capability of the secondary containment to remain intact with the primary containment breached during a pressure test with the reactor coolant temperature as high as 300°F. The results of this analysis indicated that the secondary containment would remain intact.

During a refueling outage (in Modes 4 and 5), the reactor coolant pressure boundary is not required to be intact. The inservice hydrostatic testing and system leakage pressure tests required by Section XI of the ASME Code are performed to ensure the integrity of the reactor coolant system prior to the reactor going critical after a refueling outage. This testing is only performed after the reactor coolant pressure boundary is known to be sound, by ensuring that all work on the system is cleared and testing approved by the plant staff in conformance with strict administrative procedures. This test is a verification of reactor coolant system integrity. Therefore, the Special Operations LCO and the corresponding Required Actions and Completion Times of the affected LCOs are considered to be acceptable from a safety standpoint, since performing this test is not considered to cause a safety-challenging event to occur. Therefore, the risk of allowing this option is also considered small. The system pressure or leak tests are performed nearly water solid at low decay heat values, and near Mode 4 conditions, thus the stored energy in the reactor core will be very low. Under these conditions, the potential for failed fuel and a subsequent increase in coolant activity above operating limits is minimized. In addition, small steam leaks would be detected by inspections before significant inventory loss has occurred. These studies have shown that there is no significant increase in risk to the public health and safety when performing the pressure test at temperatures > 212°F. However, there may be a higher risk of exposure and burns for inspection personnel during the leakage examinations.

4.2 Systems Aspects of Increased Pressure Test Temperatures

There may be other factors that limit the ability to perform the pressure test at these higher temperatures. The BWR pressure test is performed on critical path following a refueling outage. The sequence of events during the pressure test is concurrent with other outage activities and therefore must be coordinated to meet the requirements of these tests, including: RPV System Leak Test, Excess Flow Check Valve Test, Control Rod Scram Time Testing, and other outage cleanup activities. The pressure test is to be performed within a temperature “window” defined in the Technical Specifications; the lower temperature limit is defined by the Appendix G pressure temperature curve for pressure test, and the upper limit is the average reactor coolant temperature at which the test must be aborted. After a normal outage for refueling, the core decay heat in conjunction with pump heat is adequate to heat the system to the hydrotest test temperature, or above. The test is performed nearly water solid with a small bubble in the head to control pressure. Pressure is usually controlled by control rod drive (CRD) flow in conjunction with letdown to the condenser through the Reactor Water Cleanup (RWCU) system.

Other factors for temperature monitoring must also be considered when these tests are being conducted. For example, minimum temperature limits for the flange region (as required by 10CFR50, Appendix G [12]) are maintained by monitoring thermocouples on the outside of the vessel head. Excessive drywell cooling can actually cool the head while the primary system is being heated. Because of this, some utilities have to remove the drywell cooling from service to raise the metal temperature of the flange, and that makes the drywell temperature around the head even more unbearable for the inspectors. In addition, the once per 10-year interval pressure test extends the boundary of the inspection region to the outermost isolation valve.

When the pressure test is completed, the reactor goes from a state of high pressure and water solid level to a state of low pressure and reduced water level. Reactor pressure depressurization commences by increasing Reactor Water Cleanup (RWCU) letdown flow. Cooldown is controlled by the Shutdown Cooling System which is designed only for low pressure operation. Therefore, cooldown from the peak temperature can only commence when the system is below the interlock for shutdown cooling – typically below 75 psig. During depressurization the upper plenum region pressure must not drop below the saturation pressure corresponding to the temperature of the water surrounding the core or voids will form in that region. This presents a problem for the operators to know the actual level since the level changes considerably when the system reaches saturation pressure and develops voids and steam bubbles. The relationship between the pressure test temperature and pressure and the saturation curve is shown in Figure 4-1. At temperatures below 212°F there is little potential for the system to form voids following the test, except within the superheated region of the core. However, as the pressure test temperature increases above 212°F, the saturation temperature and pressure also increases as shown in the figure, and the potential to form voids becomes greater when the test is completed.

This has resulted in reactor water level indication problems in some BWRs when a loss of water level indication existed during the pressure reduction period. Procedure guidance, reactor water instrument configuration control and operator training must address this condition to minimize the possibility that the water level in the vessel could drop too low. One solution may be to use the Main Steam Line drains for pressure reduction to eliminate the potential for reactor water level to become too low.

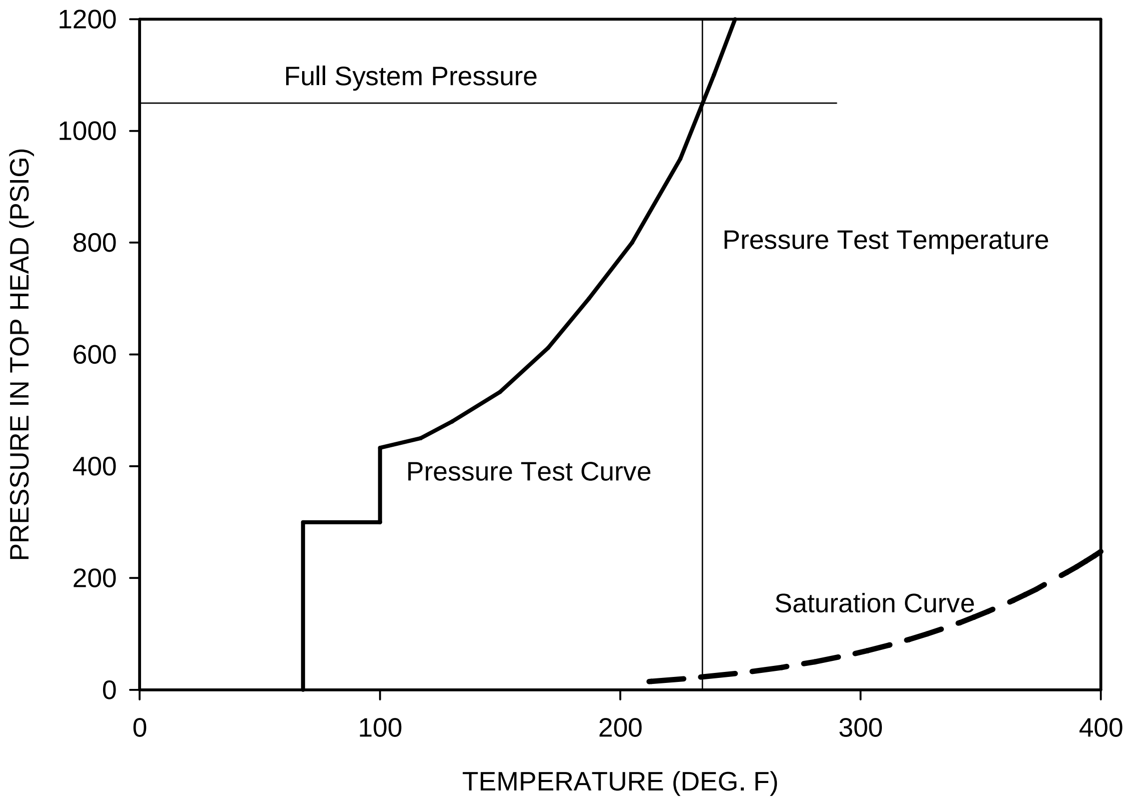

Figure 4-1
Comparison of a BWR Pressure Test Curve and the Saturation Curve

4.3 Other Significant Concerns

There may be other factors to consider regarding performing the BWR pressure test at higher temperatures.

1) Are there additional risks, costs, or safety concerns for having to perform the pressure test at these high temperatures that could be the basis to seek regulatory relief if adequate safety margins could be justified?

The answer to this question is "Yes, but mostly personnel safety risks." The personnel safety relates to personnel working in the containment during the pressure test. In a BWR there is a small opening in the bellows shield for the inspector to access the head area. He then has to open the insulation access panel to look at the head vents. If there was a steam leak in this area, it would be very difficult for him to exit the area quickly. If he was injured from the venting steam, rescue would also be difficult. The consensus from plant operators who have faced these concerns is that the risks to plant personnel are somewhat greater if the primary system temperature is above 212°F. However, some operators reported that these are not significantly worse than the risks involved in performing the pressure test at temperatures below 212°F for adequately trained inspection personnel with the proper equipment. In addition to personnel safety concerns, there are additional operational concerns that should not be overlooked. The increased likelihood of pump cavitation and premature pump seal failure from running longer times at lower pressures are real concerns for plant maintenance and operability. These two concerns can be addressed best by incorporating additional precautions for maintaining adequate net suction head pressure margins for the recirculation pumps when using pump heat to provide pressure test temperatures. Appropriate net suction head pressure margin will prevent recirculation pump cavitation and subsequent pump seal damage.

Two additional concerns arise as the result of performing the system pressure and leakage testing at temperatures > 200°F, even under the NRC-approved LCO. These concerns were anticipated many years ago, as the result of a request for regulatory guidance on the ASME Code Section XI hydrostatic and leak testing requirements. This guidance was published in 1986 as Part 9900 of the NRC Inspection Manual. The relevant text of that guidance states that.

> "The position of NRR is that the system pressure tests (leakage and hydrostatic) are to be performed before the reactor goes critical after a refueling outage. The system leakage test is a test to determine if any abnormal leakage is occurring in the reactor coolant pressure boundary after its opening and closing. The hydrostatic test is a proof test of repairs on the reactor coolant pressure boundary or other components. Prudence dictates that both of these tests be performed at the lowest temperatures that are consistent with the fracture prevention criteria for the reactor vessel or other component so that stored energy can be minimized during testing conditions by having the system water solid. The temperature correction terms are provided to account for changes in material properties when the vessel must be heated for fracture prevention. NRR does not believe that the temperature corrections are an invitation to perform the testing at higher temperatures to minimize the test pressures. The pressurizing medium is to be

reactor coolant rather than steam. NRR recognizes that some flashing to steam of any potential leakage could occur when temperatures in excess of boiling are necessary for testing. ***NRR believes that the Code section which allows testing below 200°F for corresponding pressures is prudent for the visual examination in that the risk to plant personnel is reduced and any leakage would be liquid and, therefore, more rapidly detectable***."

The last sentence of this technical position is both highlighted and italicized, since it represents the crux of the current concerns, which can be paraphrased in two questions:

1. Does system pressure and leak testing at temperatures > 200°F constitute a greater and more significant hazard to plant personnel, as stated in the NRC technical position?

2. Does system pressure and leak testing at temperatures > 200°F reduce the detection capability of the visual examinations that accompany the leakage tests, as stated in the NRC technical position?

These two questions are addressed in the following sections.

4.3.1 Personnel Hazards

The dangers to plant personnel during inspection of steam systems have long been recognized in the fossil energy and petroleum refinery/petrochemical industries as well as the nuclear industry. However, the dangers exist at system operating temperatures that are both above and below 200°F. Severe injury and death to personnel can occur from continuous leakage or from sudden rupture, provided that:

- Ambient temperature in the personnel space adjacent to the leak or rupture exceeds 120°F, and
- Moisture in the personnel space exceeds 12 % steam, by volume.

The concern is the potential for scalding and/or respiratory damage in an enclosed space, or in a space with egress problems (e.g., a long tunnel) that is subject to continuous leakage or a sudden rupture. Therefore, the OSHA regulations in Title 29 of the Code of Federal Regulations, including Part 1910, stress the concept of "permitted entry space" when an enclosed space without adequate ventilation or a long tunnel is entered for any purpose by personnel who may be subjected to either hot water or steam leakage.

In order to address the issue more quantitatively, many organizations have developed specialized guidance for particular industries. An excellent example is the American Petroleum Institute, with API 581 ("Risk-Based Inspection Resource Document," American Petroleum Institute, Washington, DC, 2000). API 581 contains worker safety guidance on potential steam releases and exposure, including the estimation of steam-affected areas around a leakage location. Human burn injury is assumed to occur at a minimum of 60°C (approximately 140°F). Fatal injuries can be caused by either thermal burns or steam inhalation, with the latter being the major contributor to mortality. The API hazard evaluation includes both continuous steam leaks and the potential for instantaneous or near-instantaneous rupture steam exposure.

In spite of this type of guidance, injuries and fatalities from steam exposure continue. The U. S. National Board of Boiler and Pressure Vessel Inspectors accumulate data on injuries and fatalities from fossil plants and industrial steam users every year. In 2001, for example, the National Board reported 84 injuries and 12 fatalities, many of which were due to steam hazards.

The major point here is that some personnel risks exist even for systems operating below 200°F. However, considering the magnitude of the temperature increase, it would appear that the risk for plant personnel would not be that much greater for systems operating at 235°F, or higher. The key consideration is that the leak would be in the form of steam rather than liquid. These risks can be mitigated by proper preparation and training of plant personnel. It should be noted that operators make rounds in areas of high temperature and pressure outside of the containment in the secondary plant; the hazards are well understood and procedures and training already exist.

4.3.2 Leakage Detection

The implication from the NRC Inspection Manual, cited above in the NRR position, is that water leakage is more readily detectable than steam leakage, so that some reduced capability of leakage detection applies at higher system pressure test temperatures. While this may be at least partially true for the case of purely ASME Code Section XI leakage testing visual (VT-2) examinations, it is not true for examination methods that are used in typical steam plant inspections, and which apply to modern nuclear power plant inspections for steam leakage. Some of the same visual examination indicators (evidence of dripping or collected condensate, rust spots on piping, and discoloration of insulation) are still used for the leakage examinations; however, because steam leaks include characteristic acoustic and thermal signatures, visual examination is augmented by infrared thermography and ultrasonic acoustic surveys that are much more sensitive than visual examination, while also providing advance warning of personnel hazards.

Many steam leaks are in fact visible, resembling water vapor. However, the turbulent flow through a leakage site is known to have strong ultrasonic components, enabling the presence of leakage to be audible to appropriate detectors, even in the presence of substantial background noise. Furthermore, since much of the leakage that is observed in nuclear power plants is first detected at locations such as valve stems, valve packing, and at other mechanical (and gasketed) joints, infrared thermography is capable of monitoring anomalies in temperature (e.g. leaking valves) that directly indicate leakage locations.

As a result of the application of combined examination methods, including conventional visual examinations and augmented thermal/acoustic methods, the capability detection of leakage at higher temperatures has not been reduced. The use of instrumentation such as temperature or humidity monitoring may be better at detecting leakage than a visual examination (e.g., VT-2), but the monitoring will not distinguish between benign leaks from packing or valves to more structurally significant leaks such as pipe cracks or stub tube cracking. A VT-2 examination is far better for locating and identifying the source of the leak, once the location has been identified by other means.

4.4 Practical Limit and Costs of Performing the Pressure Test

Aside from the safety concerns, the operational questions may be "what are the practical limits in temperature to perform the pressure test, and what are the additional costs?" The practical limit is the upper temperature that can be reasonably achieved using decay heat from the core and pump heat within approximately 24 hours. If higher temperatures are required to perform the test and these temperatures are unachievable without additional delays, then other options may be sought to provide relief. The practical limit in temperature may be different for each plant and could be very dependent on the available decay heat from the core and other heat sources such as the recirculation pumps.

The recirculation system consists of two (2) recirculation loops. The recirculation pumps are driven by variable speed motors that can control reactor power. As the flow through the loop increases, more voids are swept from the core, resulting in more thermal neutrons being produced. This, in turn, results in increasing power during normal plant operation. Although there is no power produced from the core during the pressure test, the core decay heat and the recirculation pumps can provide continuous heat to the system. Plant operators will use the recirculation pumps to heatup the system to perform the pressure test. With two pumps operating at 90% pump speed, the maximum heatup rate for the system may be as high as 7 – 8°F /hr.

There are both minimum and maximum temperature limits for the pressure test and the other tests that are typically performed at the same time. When the recirculation pumps are running, the temperature increases and, as the temperature increases, these variable speed pumps may need to be throttled to keep the temperature within the acceptable range for the test. However, to overcome system cavitation problems, the recirculation pump speed needs to be high enough to keep a positive pressure (at least 35 psig) to avoid the formation of voids during the test.

The other concern for the recirculation pumps is the increase in seal wear for longer duration, higher test temperature hydrotests. The seal assembly consists of mechanical seals built into a cartridge which can be replaced without removing the motor from the pump. The seal integrity is monitored by the pressure differential across the seals. Each of the seals carries an equal portion of the total pressure differential and is capable of sealing against the maximum pump operating pressure. The normal maintenance interval for the recirculation pump seals would be to replace the seals approximately once every three refueling outages. If the pump seal wear were to increase, it may be necessary to replace the seals once every other outage, or even more frequently.

It is difficult to quantify the costs associated with these plant limitations, but the incremental cost of the pressure test being extended by 12 hours could be equated to the cost of replacement power for that period. Using 2008 estimates for replacement power of $800K - $1,000K per day, a 12 hour delay in plant startup would be about $400K - $500K in replacement power cost per occurrence.

4.5 Potential Approaches to Mitigate the High Temperature Pressure Test Problem

The results of the evaluation suggest that pressure tests at higher temperatures can be performed and there are no inherent problems that cannot be overcome. However, there are costs and personnel risks associated with tests at higher temperature. There are also questions about the effectiveness of leak detection at higher temperatures. Ultimately, the issue comes down to the following question concerning the cost-benefit of the higher temperature tests: "Is the increase in the fracture margin corresponding to the higher temperature commensurate with the increased cost and personnel risks?" While the fracture margin is higher at higher temperatures on a deterministic basis, it is not clear that there is a significant reduction in risk when one considers the fact that vessel inspections in BWRs have found no indications (let alone finding a flaw close to the ¼ T flaw postulated in the development of the P-T curves).

Studies are being conducted by EPRI to develop a new risk-informed procedure for defining P-T limits for normal reactor startup, shutdown and pressure test conditions. In a proof-of-concept study, the risk-informed methodology demonstrated that the equivalent margin on the stress intensity factor for membrane tension in Appendix G could be reduced from 2 to approximately 1 for BWRs without causing a significant increase in the vessel failure frequency [11]. The proof-of-concept study also determined whether the probabilistic concept could be used to develop a risk-informed, deterministic calculation method as an alternative approach for inclusion in ASME Section XI, Appendix G. The results of this initial study were favorable and showed that the approach is feasible. The net effect of these potential changes to the ASME Code are that the hydrotest temperatures for BWRs could be reduced significantly while maintaining Code margins for prevention of brittle fracture of the vessel. Work is continuing in this area to develop the methodology and the technical basis for presentation to the ASME Code. It may be one or more years before this Code action may be approved, but it would provide a significant alternative method to avoid the hardships of the elevated pressure test temperatures in BWRs.

An alternative approach is to justify postulation of a flaw smaller than the ¼ T flaw currently used in Appendix G analysis. There is precedent in this since Appendix G allows use of a smaller flaw provided that there is justification. Smaller flaws have been used to develop P-T curves for other locations, e.g., vessel and closure head flange regions. If inspection techniques can be qualified to detect a smaller flaw in the belt line region, and these improved inspection methods were used for future inspections, it stands to reason that a smaller flaw can be justified for the Appendix G analysis. However, some analytical issues arise with the use of a smaller flaw size, such as possible consideration of residual and cladding stresses.

5 SUMMARY

As BWR plants continue to age, the operating utilities may need additional relief from higher required pressure test temperatures. Changes to ASME Code Section XI, Appendix G, and Article IWA-5000 have provided some relief for the calculated pressures and temperatures required to perform the hydrostatic pressure test. Also, the NRC publication of the Standard Technical Specifications for BWR plants provided a means to implement a Limited Condition of Operation to allow the pressure test to be performed at temperatures exceeding 200°F without containment isolation restrictions. Despite these Code and regulatory improvements, the pressure test temperatures may continue to increase due to changes in the vessel beltline material properties with increasing fluence. Because of this, plants will continue to have difficulties with performing the leak test, especially the inspection of the upper head region. The drywell containment design in some cases is very confined and temperatures in the upper head area can become extreme (> 130°F). The plant personnel can only work in this area for short periods of time without becoming fatigued. These problems are aggravated when the pressure test temperatures exceed 200°F.

The results of the evaluation suggest that pressure tests at higher temperatures can still be performed and there are no inherent problems in performing the leak test that cannot be overcome by improved training and protective equipment such as "ice vests" to improve stay time. However, there are additional costs and difficulties associated with performing pressure tests at higher temperatures, and the recognized risk of increased exposure to plant personnel. Also, there are questions about the effectiveness of leak detection at higher temperatures. Clearly, better options for managing this issue (i.e., performing effective leak detection and minimizing costs and personnel risks while maintaining fracture margin) are needed to avoid the additional burden. One promising option is the use of a risk-informed approach for developing P-T limit curves, including an alternative method for calculating the pressure test curve limits that would reduce the pressure test temperature. This EPRI-funded study is one or more years from completion and submission to the ASME Code for approval, but it may offer the best hope for managing the difficulties associated with the increasing pressure test temperatures in BWRs. Another option may be to justify the use of a smaller flaw for the Appendix G analysis. Both options will reduce the pressure test temperature to manageable levels while assuring sufficient fracture margins.

6
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A
EXAMPLE GENERIC TECHNICAL SPECIFICATIONS

TABLE 1.2

OPERATIONAL CONDITIONS

CONDITION	REACTOR SYSTEM MODE SWITCH POSITION	AVERAGE REACTOR COOLANT TEMPERATURE
1. POWER OPERATION	Run	Any Temperature
2. STARTUP	Startup/Hot Standby	Any Temperature
3. HOT SHUTDOWN	Shutdown	> 212°F
4. COLD SHUTDOWN	Shutdown	≤ 212°F
5. REFUELING*	Refuel	≤ 212°F

* Reactor vessel head unbolted or removed and fuel in the vessel.
* See Special Test Exception 3.10.3

SPECIAL TEST EXCEPTIONS

3/4.10.3 SHUTDOWN MARGIN DEMONSTRATIONS

LIMITING CONDITION FOR OPERATION

3/10.3 The provisions of Table 1.2 may be suspended to permit the reactor system mode switch to be in the Startup position and to allow more than one control rod to be withdrawn for SHUTDOWN MARGIN demonstration, provided the following requirements are satisfied.

1. The source range monitors are OPERABLE with the RPC circuitry shorting links removed.

2. Conformance with the SHUTDOWN MARGIN demonstration procedure is verified by a second licensed operator or other qualified member of the technical staff.

3. The "continuous withdrawal" control is not used during movement of control rods.

4. No other CORE ALTERATIONS are in progress.

APPLICABILITY: OPERATIONAL CONDITION 5, during SHUTDOWN MARGIN demonstrations.

ACTION:

With the requirements of the above specification not satisfied, immediately place the reactor system mode switch in the Shutdown or Refuel position.

REACTOR COOLANT SYSTEM

3/4.4.6 PRESSURE/TEMPERATURE LIMITS

REACTOR COOLANT SYSTEM

LIMITING CONDITION FOR OPERATION

3.4.6.1 The reactor coolant system temperature and pressure shall be limited in accordance with the limit lines shown in Figure 3.4.6.1-1 (1) curves A and A' for hydrostatic or leak testing; curves B and B' for heatup by non-nuclear means, cooldown following a nuclear shutdown and low power PHYSICS TESTS; and (3) curves C and C' for operations with a critical core other than low power PHYSICS TESTS, with:

a. A maximum heatup of 100°F in any one hour period,

b. A maximum cooldown of 100°F in any one hour period, and

c. The reactor vessel flange and head flange temperatures greater than or equal to 70°F when reactor vessel head bolting studs are under tension.

APPLICABILITY: At all times.

ACTION:

With any of the above limits exceeded, restore the temperature and/or pressure to within the limits within 30 minutes; perform an engineering evaluation to determine the effects of the out-of-limit condition on the fracture toughness properties of the reactor coolant system; determine that the reactor coolant system remains acceptable for continued operations or be in at least HOT STANDY within 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.4.6.1 During the system heatup, cooldown, and inservice leak and hydrostatic testing operations:

a. The reactor coolant system temperature and pressure shall be determined to be within the heatup and cooldown limits and to the right of the limits of Figure 3.4.6.1-1 curves A and A’, B and B’, or C and C’, as applicable, at least once per 30 minutes.

b. The reactor coolant system temperature at the following locations shall be recorded at least once every 5 minutes until 3 successive readings at each location are within ± 5°F:

1. Reactor vessel bottom drain,

2. Recirculation loops A and B, and

3. Reactor vessel bottom head.

4.4.6.1.2 The reactor coolant system temperature and pressure shall be determined to be to the right of the criticality limit line of Figure 3.4.6.1-1 curves C and C’ within 15 minutes prior to the withdrawal of control rods to bring the reactor to criticality.

4.4.6.1.3 The reactor flux specimens shall be removed at the first normal outage after one year and before the end of two years of initial operation, and examined to determine reactor pressure vessel fluence as a function of time and power level. The results of these fluence determinations, in conjunction with Bases Figure B 3/4.4.6.1-2, shall be used to update the curves of Figure 3/4.6.6-1.

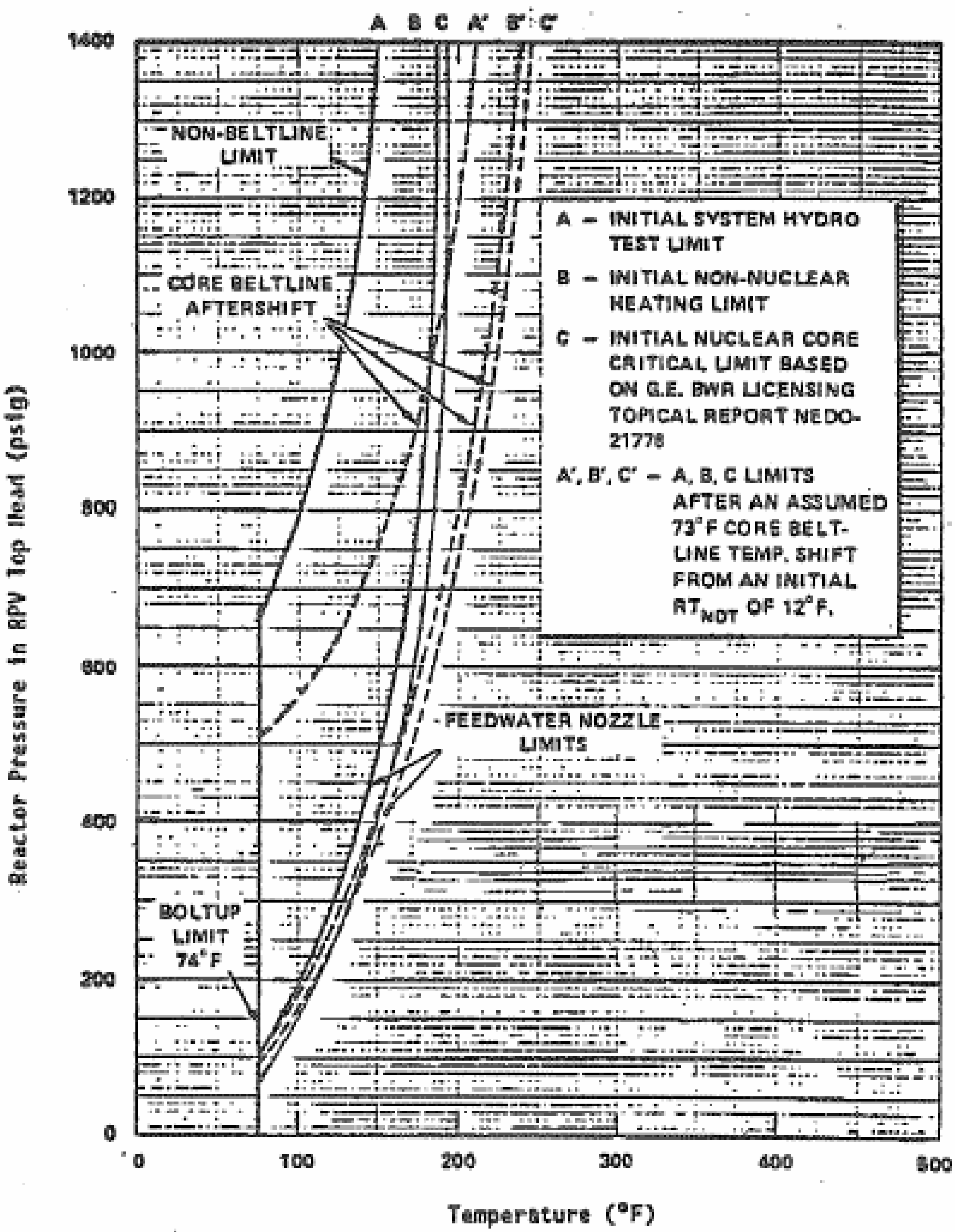
4.4.6.1.4 The reactor vessel flange and head temperature shall be verified to be greater than or equal to 70 F when reactor vessel head bolting studs are under full tension.

a. In OPERATIONAL CONDITION 4 when reactor coolant system temperature is:

1. Less than or equal to 100°F, at least once per 12 hours.

2. Less than or equal to 80°F, at least once per 30 minutes.

b. Within 30 minutes and prior to and at least once per 30 minutes during tensioning of the reactor vessel head bolting studs, except that 10% of the bolting studs may be fully tensioned below 70°F.



MINIMUM TEMPERATURE VS. REACTOR VESSEL PRESSURE

Figure 3.4.6.6-1

B

EXAMPLE IMPROVED TECHNICAL SPECIFICATIONS

LIMITING CONDITIONS FOR OPERATION

3.14 SPECIAL OPERATIONS

A. Inservice Hydrostatic and Leak Testing Operation

Specification

The average reactor coolant temperature specified in the definition of “Cold Shutdown” and “Cold Condition” may be considered “NA”, and operation considered not to be in “Hot Shutdown” or >212°F to allow performance of an inservice hydrostatic test or leak test provided that the following requirements are met:

Table 3.2A	Reactor Low Water Instrumentation
LCO 3.7.B.1	Standby Gas Treatment System (SGTS)
LCO 3.7.C.1	Secondary Containment

Applicability

During performance of inservice hydrostatic testing and system leakage pressure tests of the reactor coolant system with average coolant temperature > 212°F.

Actions

NOTE: Separate Condition entry is allowed for each requirement of the LCO.

A. One or more of the above requirements are not met:

   1. NOTE: Required Actions to be in Cold Shutdown/Cold Condition include reducing average reactor coolant temperature to < 212°F. Immediately enter the applicable Condition of the affected LCO.

SURVEILLANCE REQUIREMENTS

4.14 SPECIAL OPERATIONS

A. Inservice Hydrostatic and Leak Testing Operation

Perform the applicable surveillance requirements for the required LCOs at the frequency specified by the applicable surveillance requirements.

LIMITING CONDITIONS FOR OPERATION (continued)

SURVEILLANCE REQUIREMENTS

OR

2.1 Immediately suspend activities that could increase the average reactor coolant temperature or pressure.

AND

2.2 Reduce average coolant temperature to $\leq$ 212°F within 24 hours.

BASES:

3/4.14.A **INSERVICE HYDROSTATIC AND LEAK TESTING OPERATION**

Background

The purpose of the special operations LCO is to allow certain reactor coolant pressure tests to be performed in Cold Shutdown/Cold Condition when the metallurgical characteristics of the reactor pressure vessel (RPV) require the pressure testing at reactor coolant temperatures close to, or greater than 212°F (normally corresponding to Hot Shutdown).

Inservice hydrostatic testing and system leakage pressure tests required by Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code are performed prior to the reactor going critical after a refueling outage. Recirculation pump operation and water solid RPV (except for an air bubble for pressure control) are used to achieve the necessary temperatures and pressures required for these tests. The minimum temperatures (at the required pressures) allowed for these tests are determined for the RPV pressure and temperature (P-T) limits required by LCO 3.6.A.2, “Primary System Boundary – Thermal and Pressurization Limitations.” These limits are conservatively based on the fracture toughness of the reactor vessel, taking into account anticipated vessel neutron fluence.

With increased reactor vessel fluence over time, the minimum allowable vessel temperature increases at a given pressure. Periodic updates to the RPV P-T limit curves are performed as necessary, based upon the results of analyses of irradiated surveillance specimens removed from the vessel. In the future it is expected that hydrostatic and leak testing will eventually be required with reactor coolant temperatures exceeding 212°F. Even with the minimum temperature requirements below 212°F, the margin between the minimum test temperature and 212°F is not great enough for the operators to perform the test without a challenge to their ability to maintain temperatures below 212°F due to lack of exact control over test temperatures.

Applicable Safety Analyses

Allowing the reactor to be considered in Cold Shutdown/Cold Condition during hydrostatic or leak testing, when the reactor coolant temperature is > 212°F, effectively provides an exception to Hot Shutdown requirements, including OPERABILITY of primary containment and the full complement of redundant Emergency Core Cooling Systems. Since the hydrostatic or leak tests are performed nearly water solid, at low decay heat values, and near Cold Shutdown/Cold Condition, the stored energy in the reactor core will be very low. Under these conditions, the potential for failed fuel and a subsequent increase in coolant activity above the LCO 3.6.B.1, “Coolant Chemistry,” limits are minimized. In addition, the secondary containment will be OPERABLE, in accordance with this Special Operations LCO, and will be capable of handling any airborne radioactivity or steam leaks that could occur during the performance of hydrostatic or leak testing. The required pressure testing conditions provide adequate assurance that the consequences of a steam leak will be conservatively bounded by the consequences of the postulated main steam line break outside of primary containment described in Reference 2. Therefore, these requirements will conservatively limit radiation releases to the environment.

BASES:

3/4.14.A INSERVICE HYDROSTATIC AND LEAK TESTING OPERATION (continued)

In the event of a large primary system leak, the reactor vessel would rapidly depressurize, allowing the low-pressure core cooling system to operate. The capability of the low-pressure coolant injection and core spray subsystems, as required in Cold Shutdown/Cold Condition by LCO 3.5.A.5, “Core Spray and LPCI Systems,” are more than adequate to keep the core flooded under this low decay heat load condition. Small system leaks would be detected by leakage inspectors before significant inventory loss occurred.

For the purposes of this test, the protection provided by normally required Cold Shutdown/Cold Condition applicable LCOs, in addition to the secondary containment requirements, required by this Special Operations LCO, will ensure acceptable consequences during normal hydrostatic test conditions and during postulated accident conditions.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation at reactor coolant temperatures > 212°F can be in accordance with the other Technical Specifications without meeting this Special Operations LCO or its ACTIONS.

This option may be required due to P-T limits, however, which require testing at temperatures > 212°F, and performance of inservice leak and hydrostatic testing would necessitate the inoperability of some subsystems normally required to be OPERABLE when the reactor coolant temperature is > 212°F.

If it is desired to perform these tests while complying with this Special Operations LCO, then the Cold Shutdown/Cold Condition applicable LCOs and the current LCOs specified by LCO 3.14.A must be met. The additional requirements for secondary containment, Standby Gas Treatment system, and reactor low water level instrumentation that initiates Reactor Building Isolation and Control System will provide sufficient protection for operations at reactor coolant temperatures > 212°F for the purpose of performing either an inservice leak or pressure test.

This LCO allows primary containment to be open for frequent unobstructed access to perform inspections, and for outage activities on various systems to continue consistent with the Cold Shutdown/Cold Condition applicable requirements that are in effect prior to and after this operation.

BASES:

3/4.14.A INSERVICE HYDROSTATIC AND LEAK TESTING OPERATION (continued)

Applicability

The Cold Shutdown/Cold Condition definition may only be modified for the performance of inservice leak or hydrostatic tests so that special operation LCO 3.14.A can be considered as in Cold Shutdown/Cold Condition, even though the reactor coolant temperature is > 212°F. The additional operability requirements for secondary containment, Standby Gas Treatment system, and reactor low water level instrumentation that initiates Reactor Building Isolation and Control system when reactor coolant temperature is above 212°F provides conservatism in the response of the unit to any event that may occur. Operations in all other MODES are unaffected by this LCO.

Actions

A Note has been provided to modify the ACTIONS related to inservice leak and hydrostatic testing operation. A Note has been provided that allows separate Condition entry for each requirement of the LCO.

A.1
If an LCO specified in LCO 3.14.A is not met, the ACTIONS applicable to the stated requirements are entered immediately and complied with, Required Action A.1 has been modified by a Note that clarifies the intent of another LCO's Required Action to be in Cold Shutdown/Cold Condition includes reducing the average reactor coolant temperature to < 212°F.

A.2.1. and A.2.2
Required Action A.2.1 and Required Action A.2.2 are alternate Required Actions that can be taken instead of Required Action A.1 to restore compliance with the normal Technical Specification requirements, and thereby exit this Special Operation LCO's Applicability. Activities that could further increase reactor coolant temperature or pressure are suspended immediately, in accordance with Required Action A.2.1, and the reactor coolant temperature is reduced to establish normal Cold Shutdown/Cold Condition requirements. The allowed Completion Time of 24 hours for Required Action A.2.2 is based on engineering judgment and provides sufficient time to reduce the average reactor coolant temperature from the highest

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