Xcel Energy®

Monticello Nuclear Generating Plant
2807 W County Road 75
Monticello, MN 55362

October 26, 2012

L-MT-12-087
10 CFR 50.55a(g)

ATTN: Document Control Desk
U. S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Monticello Nuclear Generating Plant
Docket 50-263
Renewed Facility Operating License No. DPR-22

Response to Request for Additional Information Regarding 10 CFR 50.55a Request RR-005 TAC ME8071)

References: 1) Letter from Northern States Power Company, a Minnesota corporation (NSPM), d/b/a Xcel Energy to Document Control Desk, "10 CFR 50.55a Requests Associated with the Fifth Ten-Year Inservice Inspection Interval", dated February 28, 2012.

2) NRC Request for Additional Information on ISI Relief Request RR-005 Regarding Code Case N-661-2 (TAC ME8071)(ADAMS Accession No. ML12178A557), dated June 26, 2012.

Pursuant to 10 CFR 50.55a(g), Northern States Power Company, a Minnesota corporation, d/b/a Xcel Energy (hereafter "NSPM"), the licensee for the Monticello Nuclear Generating Plant (MNGP), requested NRC authorization or approval of 10 CFR 50.55a requests associated with the Fifth Ten-Year Inservice Inspection Interval (ISI) for MNGP (Reference 1). Subsequently, the U. S. Nuclear Regulatory Commission (NRC) issued a Request for Additional Information (RAI) regarding ISI Relief Request RR-005 (Reference 2). The NSPM response to the NRC RAI is provided in the Enclosure.

Summary of Commitments

This letter makes no new commitments and no revisions to existing commitments.

Should you have questions regarding this letter, please contact Mr. Randy Rippy at (612) 330-6911.

Anne E. Ward acting for Mark Schimmel

Mark A. Schimmel
Site Vice President, Monticello Nuclear Generating Plant
Northern States Power Company – Minnesota

Enclosure

cc: Administrator, Region III, USNRC
Project Manager, Monticello, USNRC
Resident Inspector, Monticello, USNRC

ENCLOSURE

MONTICELLO NUCLEAR GENERATING PLANT
RESPONSE TO NRC REQUEST FOR ADDITIONAL INFORMATION
RELIEF REQUEST RR-005
DATED JUNE 26, 2012

NRC Question:

1. ***The NRC staff notes that alternative pressure requirements for leak testing of bolted joints has been authorized for specific cases (e.g. see Accession No. ML12025A010), but is unaware of generic authorization for alternate leak testing pressure requirements for welded repairs. The NRC staff acknowledges that authorization of the proposed alternative for welded repairs could be supported on a case-by-case basis, but can envision cases, such as when the segment being tested is isolable and can be independently pressurized, where determination of hardship to support the relief may not be possible. In addition, the NRC staff questions whether pressurization of welded repairs to pressures less than that corresponding to 100 percent of normal operating pressure provides reasonable assurance of the structural integrity of the welded repair. Please provide justification for the generic use of the proposed alternative pressure requirement for leak testing of welded repairs and demonstrate that the structural integrity of welded repairs is ensured.***

Monticello Response:

Northern States Power – Minnesota (NSPM) acknowledges that the alternative referenced by the NRC in Question 1 above (ADAMS Accession No. ML12025A010) and the example of a precedent referenced in section 7 of the 10CFR50.55a Request, NRC Safety Evaluation "Monticello Nuclear Generating Plant – One Time Inservice Inspection Program Plan Relief Request No. 8 for Leak Testing the "B" and "G" Main Steam Safety Relief Valves" (ADAMS Accession No. ML031640464), were cases for authorization of leakage tests specifically on a mechanical joint. In both cases, in lieu of the requirements specified in the American Society of Mechanical Engineers (ASME) Section XI Code, the NRC authorized these acceptable alternatives to perform post repair/replacement testing and examination at a pressure less than 100% operating pressure during normal plant start-up sequence.

As mentioned in Question 1 above and Section 3.0 of the Request, the alternative described in Code Case N-795 may be applied to welded repairs, excluding the reactor vessel. With regards to isolation of a repair for testing, while some locations within the Class 1 boundary may be isolable for testing a welded repair at 100% normal pressure, several factors described in the submitted request, including existing plant conditions, ALARA, and personnel safety may impose undue hardship or prove to be unusually difficult without a compensating increase in quality or safety. These factors need to be considered when determining potential test lineups and pressurization capabilities to comply with the requirement to test the repair at 100% normal operating pressure.

Under certain conditions, isolations may require Residual Heat Removal (RHR) Shutdown Cooling (SDC) to be removed from service to perform repairs or testing, which can be operationally challenging during a short duration or forced shutdown when decay heat levels are high. Under these unusually difficult conditions, keeping SDC out of service for the extended period of time needed to perform post-repair leakage test activities at 100% normal operating pressure would prolong operational risks during an already challenging plant configuration. Although not expected, there is some inherent risk that once SDC is isolated and, a mechanical, control, or operational problem could occur which could delay returning SDC to service.

Additionally, isolations may require use of manual valves for a test boundary. A manual valve, for instance one that is the first valve between the reactor and downstream piping, may have little, if any, maintenance history due to inability to disassemble because of its direct communication with the reactor. It is possible that manual valves such as these, if relied on for isolation under test conditions, may not be able to maintain seat leakage to levels required to obtain full test pressure. These seat leakage conditions may not become evident until testing is attempted at test pressure, thereby resulting in personnel receiving unnecessary exposure to radiation and industrial safety hazards for no benefit, further complicating challenging conditions, and necessitating alternative means to perform a test that will provide reasonable assurance of detecting leakage.

With regard to requesting generic authorization of the alternative rather than on a case by case basis, NSPM prefers to have generic authorization for using the alternatives in the Code Case, as presented in the submitted Request, to be able to consider all applicable factors in determining the plant configuration for testing repairs within the Class 1 boundary without undue hardship or delays in returning the unit to its normal configuration. NSPM may choose to isolate a repair for testing when practicable, but if plant conditions such as decay heat, dose rate, personnel safety, valve seat leakage, or other conditions are not conducive to reasonably performing the test in that manner, MNGP could implement the generically approved alternative to proceed with testing at slightly reduced pressures during normal startup conditions, as needed. NSPM believes that testing under the alternative conditions of the Code Case, and using the additional hold times and pressure specified in the Request, provides reasonable assurance of detecting any leakage for both mechanical joints and welded repairs.

With respect to structural integrity, during the development of Code Case N-416, "Alternative Pressure Test Requirements for Welded or Brazed Repairs, Fabrication Welds or Brazed Joints for Replacement Parts and Piping Subassemblies, or Installation of Replacement Items by Welding or Brazing, Classes 1, 2, and 3" and Code Case N-498, "Alternative Requirements for 10-Year System Hydrostatic Testing for Class 1, 2, and 3 Systems", the ASME concluded that the hydrostatic test (a test using pressure higher than a system leakage test) was not a structural integrity test, but a leakage test. The fact that the hydrostatic test was not verifying structural integrity served as the basis for replacing the hydrostatic test with the system leakage test for both periodic and post-repair/replacement activity pressure testing. Revisions of both Code Cases are conditionally approved by the NRC via Regulatory Guide 1.147, Table 2.

The technical basis that supports Code Case N-416 and N-498 is documented in an ASME White Paper "Inservice Inspection Pressure Testing in Class 1, 2 and 3 Systems" prepared for the Special Working Group on Pressure Testing (Attachment 1 to this response). The information in the White Paper demonstrates that both the Section XI hydrostatic test and the system leakage test is a leakage test and not a structural integrity test.

With adherence to ASME Section XI repair/replacement requirements, the structural integrity of a pressure boundary welded or brazed joint or repair is derived from the design and fabrication requirements of the Construction Code, including the Construction Code nondestructive examinations used for the repair/replacement activity, not the subsequent leakage test. As such, a condition of the NRC's approval of Code Case N-416 requires use of examination methods and acceptance criteria of the 1992 Edition of ASME Section III or later for welds or brazes that are pressure tested using the leakage test when the original Construction Code is other than Section III. A similar condition is provided in 10 CFR 50.55a(b)(2)(xx)(B) by mandating application of paragraph IWA-4540(a)(2) from ASME Section XI, 2002 Addenda when using the 2003 Addenda through the latest Edition/Addenda referenced in 10 CFR 50.55a(b)(2).

Based on the research performed by ASME as well as previous justifications for alternatives authorized by the NRC for post-repair/replacement pressure tests at slightly reduced pressures, NSPM concludes that the effect of testing at a pressure that corresponds with 90% of rated power versus 100% of rated power is not a reduced validation of structural integrity, but rather a potential in leakage rate reduction, including testing for welded repairs.

Research described in the attached White Paper performed by Argonne National Laboratory, as commissioned by the NRC, indicates that the relationship of leakage and pressure is relatively linear. Therefore, NSPM concludes that leakage rates associated with pressure at 90% of normal operating pressure would be approximately 10% less than a leakage rate at 100% of normal operating pressure. However, any reduction in leakage rate is more than compensated for by the increase in hold times proposed by NSPM versus the hold times required by IWA-5213(b) (increased by 600% for noninsulated and 200% for insulated). Other research cited in the attached White Paper supports the conclusions of Argonne National Laboratory.

NRC Question:

2. ***Please describe the methods for attaining 100% of normal operating pressure required by IWB-5221(a) in order to perform the Code-compliant system leakage test and describe the hardship or unusual difficulty associated with each.***

Monticello Response:

In the 10CFR50.55a Request listed as a precedent in Section 7.0 of this Request (ADAMS Accession No. ML031750517), which was authorized for one-time use by the NRC in the MNGP 4th ISI Interval, Nuclear Management Company (NMC) identified three methods that comply with IWB-5221(a) for performing the system leakage test at a pressure corresponding to 100% rated power subsequent to a repair/replacement activity that occurs during a maintenance or forced outage (other than a refuel outage). The conditions associated with such testing represent an imposition on personnel safety, personnel radiation exposure, challenges to the normal mode and manner of equipment operation, or may cause excessive outage durations without a compensating increase in the level of quality and safety.

Method No. 1 would perform the pressure test and VT-2 exam during normal startup procedures. During normal startup with normal power ascension, nominal operating pressure of 1000 psig is reached at a reactor power level of approximately 85%. If access to containment were permitted at this power level, personnel would be exposed to excessive radiation levels, including significant exposure to neutron radiation fields, which is contrary to station ALARA practices.

Establishing the 1000 psig test condition at a more moderate power level (e.g. during plant startup at approximately 5% reactor power) and in the manner needed to address radiation concerns would require altering the normal operational mode of the steam pressure control system.

During the performance of plant startup procedures, the electric and mechanical pressure regulator (EPR and MPR) set points are established within their normal operational ranges (approximately 910 psig). Their primary function is to regulate the main steam system pressures as sensed near the inlet of the high-pressure turbine. Reactor pressure control at the nominal 1000 psig is achieved at higher reactor power levels as a function of the pressure control system and the induced differential pressure across the main steam isolation valves and main steam piping.

While it is potentially technically feasible to manipulate these controls to establish the nominal system pressure of 1000 psig at lower power levels, there is no nuclear analysis that supports this mode of operation, and doing so will affect core reactivity and could challenge plant safety systems, such as the reactor protection system (RPS). MNGP has not previously operated the EPR and MPR in this manner. Changing the setpoints outside of the normal range of operation for the purpose of performing this test at nominal operating pressure poses several operational challenges. The lack of experience and predictability of setting pressure regulators outside the normal range of operation challenges operations with the potential risk of adversely impacting reactor safety.

Method No. 2 would implement the reactor coolant pressure boundary system leakage test conducted to meet the requirements of Table IWB-2500-1, Category B-P. The reactor pressure vessel (RPV) is filled with coolant and the steam lines are flooded to provide a water-solid condition. Use of this method would result in multiple operational challenges. Extensive valve manipulations, system lineups, and procedural controls are required in order to heat up and pressurize the primary system to establish the necessary test pressure, during plant outage conditions, without the withdrawal of control rods. The testing is expected to take approximately 1 day of outage time, and the additional valve lineups and system reconfigurations necessary to support this test impose an additional challenge to the affected systems. After completion of the testing and subsequent recovery from the test procedure, normal plant startup then occurs.

For Method 2 during a short duration shutdown or forced outage, the higher decay heat creates a significant challenge to the operations staff while performing pressurization for the test. To support the test pressurization evolution, the normal decay heat removal system, RHR-SDC, would be required to be removed from service and isolated from the vessel pressurization boundary because the RHR-SDC system is not designed to withstand pressures greater than 185 psig. Thus, the remaining system available for decay heat removal is the reactor water cleanup system (RWCU). Pressurization for the test would be provided by decay heat and the reactor recirculation pumps, with pressure balancing performed by the control rod drive (CRD) system and RWCU.

The decay heat load for this configuration adds temperature control challenges to the operations staff, further increasing the risk of an operating event. During a past short duration shutdown at MNGP, application of ANSI / ANS -1994 decay heat code indicated a significant level of decay heat load. The ratio of decay heat input versus the heat removal capacity provided by RWCU was approximately 4:1. Therefore, the decay heat generated by the reactor core would surpass the capacity of RWCU. The heat up rate of the vessel water would cause the temperatures to surpass 212° F prior to the initiation of the inspections.

Method 2 could present other operational challenges as well. During test pressurization, the pressure increase would be obtained by balancing the flow into the vessel, which is provided by the control rod drive (CRD) system, with the flow out of the vessel provided by the RWCU system via the dump flow control valve and flow controller. This is the method used during refueling outages to complete the RPV system leakage test. A failure of a component, such as the dump valve or flow controller, would cause the interruption of dump flow and would cause the RPV pressure to increase. The RPV pressure would increase until operator action would require the operating CRD pump to be tripped. Due to the amount of decay heat being generated and the RWCU systems heat removal capacity, the RPV may continue to pressurize and may require further operator action to depressurize the RPV. Operator actions may include one or more of the following: reestablishing RWCU dump flow if the failure mechanism was no longer present, opening the main steam line drain valves, head vent line, or SRVs. Any of the last 3 of these actions would likely cause a rapid depressurization of the RPV.

Method No. 3 would maintain the RPV at its normal level and use decay heat to produce sufficient steam pressure to conduct the test at nominal operating pressure.

However, while the decay heat load is too high for the water-solid method discussed above (Method 2), as observed during a recent short duration forced shutdown at MNGP, there may not be sufficient decay heat available to perform the test at 1000 psig within a reasonable time period, if at all.

In summary, each of the three methods discussed above that comply with IWB-5221(a) requirements for testing at 100% normal operating pressure present a hardship or unusual difficulty to MNGP without a compensating increase in quality and safety.

NRC Question:

3. ***Please describe the method for attaining 90% of normal operating pressure in order to perform the proposed alternative leakage test.***

Monticello Response:

The method to obtain 90% of the pressure that corresponds to 100% rated power is the same as Method 1 described in response to the NRC's Question 2, using normal startup procedures with normal power ascension, except that the test condition (a minimum of 900 psig) can be achieved at approximately 5% power. At this power level, personnel can enter the containment for short durations to perform the VT-2 examination of a repair/replacement activity.

NRC Question:

4. ***The Basis for Use of the proposed alternative states that the core decay heat during a maintenance outage is much higher than that after a refueling outage, and that the heat load is difficult to control once shutdown cooling is removed from service.***

    a. ***What are the temperature and pressure limits for use of shutdown cooling?***

    b. ***Given these limits, please explain why pressurization to 90 percent normal operating pressure, with a hold for up to 8 hours, is possible but pressurizing to 100 percent normal operating pressure is unusually difficult.***

Monticello Response:

a. When taking suction from the reactor vessel, the RHR System cannot be placed into operation in the shutdown cooling mode until the reactor pressure interlock on the shutdown cooling suction valves has been reset. This is at a reactor dome pressure of 74 psig which corresponds to 113 psig RHR pump suction pressure. The 74 psig reactor pressure corresponds to a saturation temperature of approximately 320°F. The shutdown cooling system is designed for a maximum pressure of 185 psig at a temperature of 330°F.

b. As described in response to Question 2, two of the three methods to obtain a test pressure that corresponds with 100% rated power either causes the unit to be placed in abnormal conditions that challenge plant and/or personnel safety or exposes personnel to excessive radiation. The third method results in unreasonable delay from outage recovery and can substantially postpone restart. By performing the VT-2 examination at 900 psig, this allows the plant to secure from the outage and proceed with a normal restart. Once power level has reached approximately 5% (a minimum of 900 psig), the unit can suspend power ascension to allow for the 1 hour uninsulated or 8 hour insulated hold time by using normal pressure and temperature control methods. At this power level with a corresponding pressure of ≥900 psig, personnel will be able to enter the containment to perform the VT-2 examination without undue safety hazards or excessive radiation exposure.

MONTICELLO NUCLEAR GENERATING PLANT
RESPONSE TO NRC REQUEST FOR ADDITIONAL INFORMATION
RELIEF REQUEST RR-005
DATED JUNE 26, 2012

ATTACHMENT 1

(37 pages to follow)

Inservice Inspection Pressure Testing
in
Class 1, 2 and 3 Systems

Prepared

for

Special Working Group Pressure Testing

December 10, 1990

S. R. Gosselin, P.E.

Southern California Edison Company

TABLE OF CONTENTS

ASME Section XI
Inservice Inspection Pressure Testing
Class 1, 2 and 3 Systems

Numerous Code inquiries prompted the formation of a Special Working Group on Pressure Testing (SWGPT) to review the current pressure testing requirements in Section XI. These requirements are divided into two main groups: 1) pressure testing at the completion of repair and/or replacement activities, and 2) routine pressure testing (leak tests and hydrostatic tests) which are performed during the course of each inservice inspection (ISI) interval. The SWGPT has initially concentrated its efforts on the latter.

1.0 ISI PRESSURE TESTING REQUIREMENTS

During each ISI inspection interval (approximately every 10 years) routine pressure tests are required to be performed on all Code Class 1, 2 and 3 systems and components. These tests may be classified into one of two types; system leakage tests and hydrostatic pressure tests. System leakage tests are conducted at nominal system operating pressure. They may also be referred to as functional tests or inservice tests. Usually they are performed during normal system operation. Hydrostatic pressure tests are conducted at some pressure above nominal operating pressure. The required frequencies for both type tests are contained in Tables IWB-2500-1, IWC-2500-1 and IWD-2500-1.

Class 1

As Described in IWB-5000, the inservice inspection (ISI) interval pressure tests for Class 1 systems are conducted at a frequency and method stated in Table IWB-2500-1 Category B-P. Accordingly, a System Leakage Test (IWB-5221) is performed each refueling outage and a System Hydrostatic Test (IWB-5222) once every inspection interval (approximately once every 10 years).

The system leakage tests is conducted at a test pressure not less than nominal operating pressure (P_o) associated with 100% reactor power. Unlike the leak test, the hydrostatic test pressure requirements are dependent upon test temperature (reactor coolant system (RCS) temperature). These test pressures, identified in Table IWB-5222-1, range from as high as 1.1 x P_o in "cold" condition (<100 °F) to as low as 1.02 x P_o in a "hot" (>500 °F). For most plants, P-T limits (Appendix G) in the plant Technical Specifications prevent pressurizing the RCS to P_o when RCS temperature is low. Additionally, performing the hydrostatic test in the hot condition, minimizes the operating procedural impacts and need for temporary test equipment. Consequently, all Class 1 ISI hydrostatic tests are being conducted hot.

These pressure tests are normally conducted at or near the end of a refueling outage. Since these systems are not assessable during normal operation, the testing serves to verify system operability prior to return to service.

Class 2 and 3

The ISI interval pressure tests for Class 2 and 3 systems are conducted at a frequency and method stated in Tables IWC-2500-1 Category C-H and IWD-2500-1 respectively. System leakage tests at nominal operating pressures are conducted a minimum of once each inspect period (i.e. every 36-40 months). As in the case of the Class 1 systems, a system hydrostatic test is required once every inspection interval.

The rules for the system hydrostatic test are the same for Class 2 and 3. For these systems, the hydrostatic test is required to be conducted at 1.1 x P_{sv} for systems with design temperatures <200 ^{o}F, and 1.25 x P_{sv} for systems with design temperatures >200 ^{o}F. P_{sv} represents the lowest setting among the safety and relief valves provided for overpressure protection. For most systems, P_{sv} is equal to system design pressure, P_{Design}.

2.0 DEMONSTRATION OF STRUCTURAL INTEGRITY

In October 1986, D. R. Pitcairn of Structural Integrity Associates submitted his report entitled "Post-Repair Pressure Testing" to the Section XI Working Group on Repairs and the SubGroup on Containment. He suggested that, in light of the reduction in system hydrostatic test pressures permitted in Table IWB-5222-1, the Code committee should review the technical bases for all elevated pressure testing. Pitcairn went on to conclude that all ASME Section XI system pressure tests are basicly leak tests and do not impose a significant challenge to the structural integrity of the system.

Similar conclusions were reached in a recent study by R. Gamble of NOVETECH in his evaluation prepared for the Special Working Group on Pressure Testing (SWGPT) dated, February 1990. Gamble's analysis considered an irradiated PWR reactor vessel, 8.7" wall thickness and 183" outside diameter. Cooldown curves were conducted using the procedures in Appendix G of Section XI. The vessel was pressurized in an isothermal condition, similar to the expected during a plant hydrostatic test.

The results, summarized in Figure 1, indicate that the current ASME Section XI Class 1 hydrostatic test could at best demonstrate that the reactor vessel did not have a crack >80% through wall and a material toughness $<K_{IR}$. This assumes that

the pressure test is conducted at 110% of nominal design operating pressure (2700 psi) and a test temperature of $RT_{NDT}+90^{\circ}F$ (below $RT_{NDT}+90^{\circ}F$ PWR plant technical specifications require LTOP protection be established). Since the RT_{NDT} used to determine could include the 2 sigma term in Regulatory Guide 1.99 Rev. 2, then the hydrostatic test also indicates that RT_{NDT} is no more than the mean minus 2 standard deviations. Gamble points out that the combination of these variables is a very low probability event; consequently, the current hydrostatic test tells little about the vessel structural condition.

Gamble's results confirm recently obtained EPRI PRA and probabilistic fracture mechanics analyses for BWR hydrostatic tests (EPRI report, to be published). These studies show that the failure probability associated with a Section XI hydrostatic pressure and temperature requirements was extremely low. At current hydrostatic test pressures, temperature would have to be reduced as much as 50-60°F in order to produce failure probabilities in the range of 10^{-6}.

If one is to assume that the intent of Section XI pressure testing is to demonstrate a predefined integrity condition prior to returning the plant to service, then significant changes to the existing hydrostatic test requirements would be required. Testing would need to be conducted at very low temperatures and high pressures ($>1.25 \times P_{Design}$). For the PWR vessel in Figure 1, test pressures would need to be increased to approximately 3200 psia at a test temperature of $RT_{NDT}+90^{\circ}F$ in order to demonstrate vessel integrity to Appendix G criteria. The SWGPT concluded that, any benefits derived from a periodic pressure test of this magnitude were insignificant when compared to the extreme operational hardships, high costs, and personnel/equipment safety concerns it would impose on the utility.

Many other types of loadings are present (thermal expansion, seismic, mechanical vibration etc.) which cannot be simulated merely by testing at increased pressures. Additionally, actual reactor vessel material toughness is not as low as K_{IR} which further lessens the effectiveness of the this test as and accurate indicator of structural integrity.

Unlike the Class 1 systems, Class 2 and 3 systems are tested to 1.1 x P_{SV} (for systems with design temperature >200°F) or 1.25 x P_{SV} (for systems with a design temperature <200°F). For most systems, $P_{SV} = P_{Design}$; which may be significantly greater than nominal system operating pressure. Despite this, the ability of the Class 2 and 3 hydrostatic tests to detect "hidden" flaws is similar to the Class 1 test. These systems generally have a much lower design pressures and are not subjected to radiation embrittlement. In fact, experience has demonstrated that failures are <u>not</u> being discovered as a result of a hydrostatic test pressures propagating a preexisting flaw through wall.

Failures, except in rare instances, are being found when the system at normal operating pressure.

Much of this can be attributed to failure mechanisms which have not manifested themselves in Class 1 systems. Operating experience has shown that moderate energy systems used for cooling are subject to degradation by various phenomena such as corrosion, microbiological induced corrosion (MIC), cavitation etc. Further, high energy feed and steam systems are also subject to erosion-corrosion. Some Class 3 systems may not be redundant (i.e. contain common supply/return headers) and may not be able to be isolated for hydrostatic testing in an operating plant. Consequently, Section XI hydrostatic pressure testing is not considered effective or reliable for detecting this degradation.

The SubGroup on Water Cooled Systems and the SubGroup on Nondestructive Evaluation need to pay specific attention to these issues; At this time, the Code has not established ISI standards in this area; however, utilities are implementing erosion-corrosion and MIC programs despite the absence of Code requirements. Continuing to require a Class 3 hydrostatic test every 10 years is not a solution; final or interim. Frequent system walkdown inspections by plant operators combined with a routine system leakage test is an effective and practical approach.

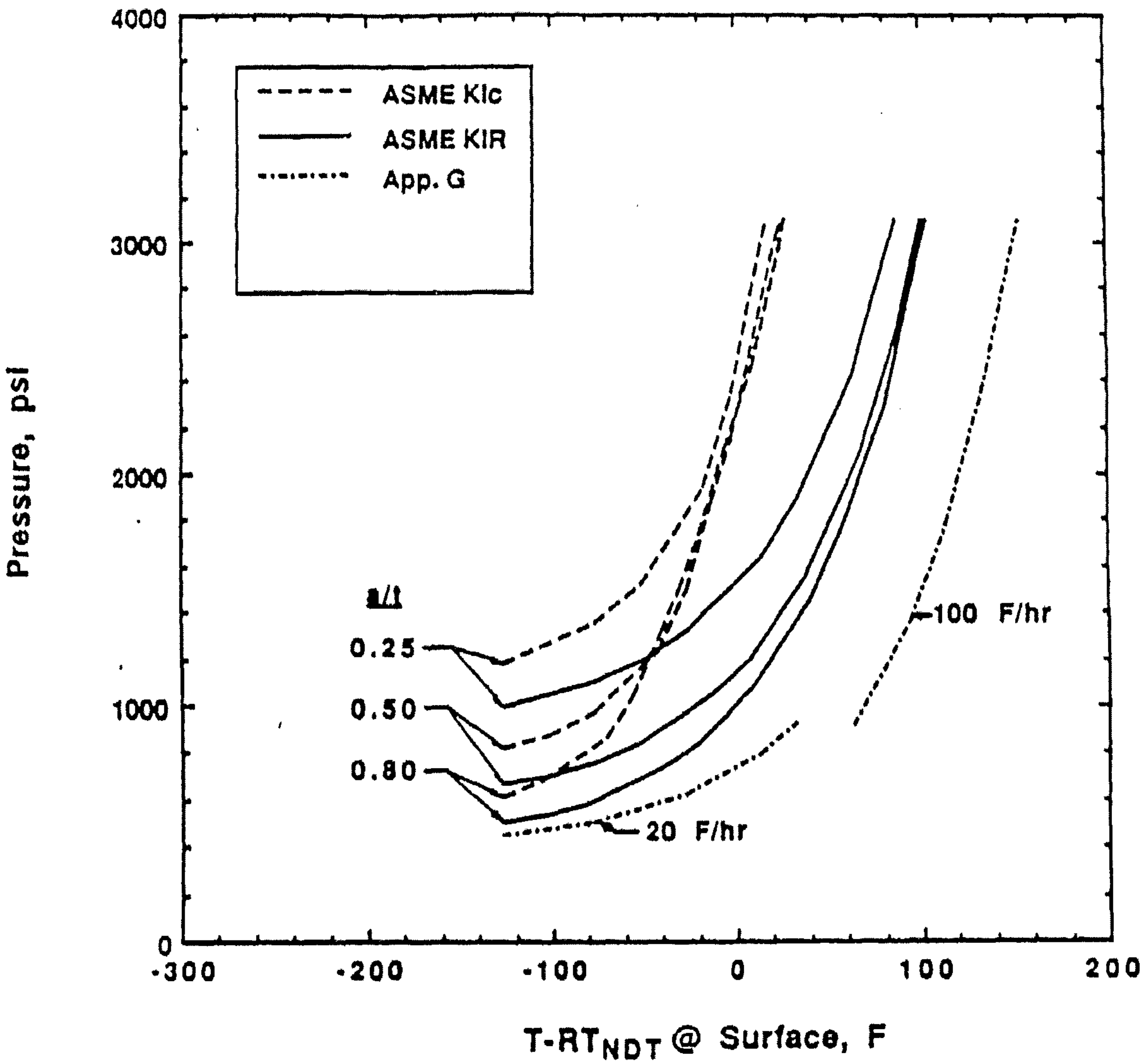


Figure 1. Pressure-Temperature Limit Curves for Various Surface Crack Depths and Toughnesses Compared With the ASME Section XI Hydrotest Condition: PWR, t = 8.7-inch, OD = 183-inch

3.0 LEAKAGE DETECTION

The SWGPT concluded that the purpose of pressure testing in Section XI is the find leaks. When testing insulated systems, the Code has always relied upon a 4 hour hold time to allow leakage to accumulate and become visible to the VT-2 inspector. The technical bases for this time is not know; however, experience has shown it to be effective.

Argonne National Laboratory, was commissioned by the NRC to experimentally measure flow rates through intergranular stress corrosion cracks (IGSCC). In doing so, they attempted to examine the pressure dependency of leakage through 3 field induced IGSCC. Measurements were obtained at 72 °F and 200°F. The largest flaw was approximately 1 inch long at the outside surface of a 10 inch pipe. The data collected at 200°F was somewhat more reproducible than that collected at room temperature.

Leakage as high as 2 ml/min in the 1" crack at approximately 1900 psi was measured. This would result in approximately 1 pint of water over a 4 hour period. Most likely this would be detectable. In general for a given flaw length, the relationship of leakage and pressure was relatively linear and the differences in flow rates at P_o and 1.1 x P_o were typically <25%.

Northeast Utilities compiled various PICEP computer runs to examine the effect of test pressure on leakage rate. A sampling of various Class 2 and 3 piping systems were reviewed. The leak rate through a fatigue type cracks, ranging from 1-10 inches in length, were calculated at the operational leak test pressure and the Section XI hydrostatic test pressure. For many of the Class 2 and 3 systems selected, the nominal operating pressure was much less than the design pressure. Despite this the PICEP results indicated that the relative difference in predicted leakage was small at the smaller crack sizes. In all cases the leakage was sufficiently large enough to be identified.

4.0 UTILITY PERSPECTIVE

The overwhelming opinion of utilities is that the current hydrostatic pressure testing requirements in Section XI place unwarranted hardships on operating power plants. The hydrostatic tests do not provide any additional information necessary to assure safe operation. The costs and operational difficulties associated with these tests overwhelm any benefits which might be obtained.

The Class 1 hydrostatic tests are typically performed on critical path. For PWRs the overall impact on the outage is relatively small. These tests are conducted hot, and at conditions slightly above normal operating pressure. However, this is not the case for the BWR. Typically, the BWR is forced to use reactor heat in order to attain required test temperatures or face long outage extensions. These efforts must be employed in order to perform nothing more than a leak test. A PWR operating at 2250 psia, will conduct a Section XI hydrostatic test at 2295 psia; 45 psia above normal operating pressure. A routine system leakage tests performed at each refueling outage would provide the same information.

Since many of the Class 2 and 3 systems cannot be removed from service during plant operation, the hydrostatic tests must normally conducted during plant outages and typically will at some time be on critical path. Since test pressures are higher than design, they require a significant effort to setup and perform. Special test equipment, valve lineups, and procedure are required. Depending on the plant, the number of Class 2 and 3 hydrostatic tests required to be performed during the inpection interval may number from 19 to 65 or more.

In a recent outage at San Onofre Unit 1, a total of 5 Class 2 and 3 hydrostatic tests were conducted. This effort involved approximately 2100 MHRS (not including planning hours for testing and repairs) and an ALARA cost of 3 MREM. The Section XI program at SONGS 1 contains approximately 65 Class 2 and 3 hydrostatic tests.

A typical Class 2 hydrostatic test will require approximately 5 days to complete. They usually involve 2 engineers, 3-5 maintenance persons, 2 plant operators, and 1-2 quality control inspectors. One day is required to locate and install temporary test equipment. Valve lineups and system fill and vent activities will usually require an additional day. One day is required to recover from the completion of the test. Generally, it will take anywhere from 1-2 days to actually perform the hydrostatic test.

One of the main problems associated with these tests is the rework of plant equipment necessary in order to obtain the higher test pressures. This is due to the fact that pressurizing the system above design pressure places special requirements on plant equipment (valves, pumps, flanged connections etc.) which they would not be exposed to during normal or accident conditions. Hydrostatic test pumps are typically low capacity and test boundary tightness must be relied on by in line equipment. Any significant leakage may render it impossible to attain test pressure. In fact, during normal or accident conditions the pretest tightness of these items is usually adequate. Consequently, the utility is forced to rework equipment so it can perform at a level beyond what the system design would require.

5.0 CONCLUSIONS

Recent PWR and BWR independent studies have concluded that the current Section XI system hydrostatic pressure test requirements tell little about the structural condition of plant components. Unless test temperatures can be significantly reduced and test pressures substantially increased, the Section XI hydrostatic test will not provide any significant information beyond that which could be obtained from a system leak test at normal operating conditions.

The purpose of pressure testing in Section XI is to find leaks. In doing so the utility is able to ascertain the system/component operability, and institute repairs as appropriate. Experience has shown that conducting leakage tests at normal operating pressures will not prevent inspectors from locating external leakage. Establishing a 4 hour hold time for insulated components, should provide adequate time for leakage to accumulate and be visible to a trained VT-2 inspector.

The 10-year hydrostatic pressure tests are placing an extreme hardship on utilities with little to no benefit. The Class 2 and 3 systems are being subjected to service induced failures which do not appear to manifest themselves in Class 1 systems (e.g. erosion corrosion and MIC). The 10-year hydrostatic tests being conducted on these systems do not identify these conditions.

Currently, Class 2 and 3 systems receive system leakage tests once each inspection period. This works out to be approximately every 36-40 months. This frequency appears to be acceptable, especially when one considers that many of these systems routinely receive walkdown inspections by plant operators in addition to the formal testing in Section XI.

6.0 RECOMMENDATIONS

Class 1

The pressure testing Section XI requirements for Class 1 systems, as described in Table IWB-2500-1 Category B-P, should be revised to eliminate the hydrostatic pressure test (IWB-5222). The following should be performed:

(a) A system leakage test should be performed once each refueling outage, prior to reactor startup. The purpose of this test will be to identify system leakage and allow operating staff to assess the system operability prior to return to service.

(b) The boundary subject to test pressurization and accompanying VT-2 visual inspection during the system leakage test should extend to all Class 1 pressure retaining components within the system boundary.

(c) Prior to the start of the system leakage test, the system should be pressurized to nominal operating pressure for a minimum of 4 hours for insulated systems and 10 minutes for noninsulated systems. The system should be maintained at nominal operating pressure during the performance of the visual VT-2 examination.

(d) System leak test temperatures and pressures should not exceed limiting conditions for hydrostatic test curve as contained in the facility Technical Specifications.

<u>Class 2</u>

The pressure testing Section XI requirements for Class 2 systems, as described in Table IWC-2500-1 Category C-H, should be revised to eliminate the hydrostatic pressure test (IWC-5222). The following should be performed:

(a) A system leakage test should be performed once each inspection period.

(b) The boundary subject to test pressurization and accompanying VT-2 visual inspections during the system leakage test should extend to all Class 2 components included in those portions of systems required to operate or support the safety system function up to and including the first normally closed valve (including a safety or relief valve) or valve capable of autoclosure when the safety function is required.

(c) Prior to the start of the system leakage test, the system should be pressurized to nominal operating pressure for a minimum of 4 hours for insulated systems and 10 minutes for noninsulated systems. The system should be maintained at nominal operating pressure during the performance of the visual VT-2 examination.

<u>Class 3</u>

The pressure testing Section XI requirements for Class 3 systems, as described in Table IWD-2500-1, should be revised to eliminate the hydrostatic pressure test (IWD-5223). The following should be performed:

(a) A system leakage test should be performed once each inspection period.

(b) The boundary subject to test pressurization and accompanying VT-2 visual inspections during the system leakage test should extend to all Class 3 components included in those portions of systems required to operate or support the safety system function up to and including the first normally closed valve (including a safety or relief valve) or valve capable of autoclosure when the safety function is required.

(c) Prior to the start of the system leakage test, the system should be pressurized to nominal operating pressure for a minimum of 4 hours for insulated systems and 10 minutes for noninsulated systems. The system should be maintained at nominal operating pressure during the performance of the visual VT-2 examination.

The SubGroup on Water Cooled Systems and the SubGroup on Nondestructive Evaluations should review the Class 3 systems with regard to erosion corrosion and MIC. A sample inspection of locations, subject to these type degradation mechanisms, should be considered for selective Class 3 systems. The Code should not be prescriptive in defining the inspection program in terms of areas to be examined. The program should be developed by the Owner based on the plant specific conditions.

REFERENCES

1. Kupperman, D.S., Argonne National Laboratory, Experimentally Measured Flow Rates Through IGSCC, April 30, 1990, Letter to R. Hermann, USNRC-NRR.

2. Gosselin, S. R., Southern California Edison Co., Minutes for Task Group Meeting, August 20, 1990, Committee Correspondence to SWGPT Members.

3. Gamble, R., NOVETECH, Section XI Hydrotest, February 13, 1990, Committee Correspondence to SWGPT Members.

4. Pitcairn, D. R., Riccardella, P., Post-Repair Pressure Testing, October 1986, Prepared for the Working Group Repairs and SubGroup on Containment.

5. ASME Boiler and Pressure Vessel Code, Section XI, 1990 Edition.

ALTERNATIVE RULES FOR ASME SECTION XI INTERVAL PRESSURE TESTING FOR CLASS 3 COMPONENTS. (REVISION TO CODE CASE N-498)

ABSTRACT

This document presents the argument for the deletion of the Class 3 Interval Hydrostatic Test, required by ASME, Boiler & Pressure Vessel Code, Section XI. This test is required to be performed at the end of each ten year interval. This is a stand alone document but the information presented is written to supplement the information provided in "Inservice Inspection Pressure Testing in Class 1, 2, and 3 Systems", December 10, 1990.

INTRODUCTION

In 1989 a Special Working Group was formed to evaluate the pressure testing requirements of Section XI. A Task Group (TG) was formed to review the Interval Hydrostatic Pressure Test (elevated pressure) of systems every ten years. The results of this group's effort is documented to "Inservice Inspection Pressure Testing in Class 1, 2, and 3 Systems", December 10, 1990, and Code Case N-498 was a product of the group's efforts. When N-498 was written only Class 1 and Class 2 systems were included. The TG had reservations about the inclusion of Class 3 systems into the case until certain issues could be resolved. A new TG was formed to work on those issues.

The new TG focused on four issues. The first two were added to provide background and continuity for this document. The last two, were the issues carried over from the first TG.

- Purpose of Interval Pressure Testing
- Class 3 System Classification (NRC Regulatory Guide 1.26)
- NDE and Impact Testing in Class 3 systems per Section III
- History of failures found during hydrostatic testing

PURPOSE OF INTERVAL PRESSURE TESTING

A pressure test is required to be performed on a system once a Period (3 years) with three Periods per Interval (10 Years). System leakage tests are preformed for the first two Periods with the system hydrostatic (elevated pressure) test being performed in the last or third Period. These tests provide the plant owner a systematic approach to locate leaks in system pressure boundaries.

The original philosophy and reasoning for the ASME, Section XI system hydrostatic pressure test was extracted from the paper titled "DEVELOPMENT OF INSERVICE INSPECTION SAFETY PHILOSOPHY FOR U.S. NUCLEAR PLANTS" written by S.H. Bush and R.R Maccary.

> *"The system hydrostatic test was originally designed to allow inspection for evidence of any leakage that might originate from* ***through-wall*** *cracks of the pressure boundary and to enhance the possibility of timely discovery of small* ***through-wall*** *flaws which, because of leak size, might not be readily detected by the installed leak detection systems. As stated in the referenced document the inservice system hydrostatic pressure test required by ASME Section XI Code reflects the acceptance of the pressure test as, primarily, a means to enhance leakage detection during the examination of components under pressure rather than solely as a measure to determine the structural integrity of the components".*

The focus of the Bush and Maccary paper is on the Class 1 System located in the Reactor Containment where leakage detection systems are used. The idea of performing hydrostatic tests to look for leaks was carried over to the Class 2 and 3 systems. Although the tests are called hydrostatic, the test conditions for Class 1 is different from those of Class 2 and 3.

The Class 1 test is temperature dependent on the nominal operating pressure (Reactor Power of 100%) vice the system design pressure for Class 2 and 3. This difference for Class 1 is due to the Reactor Vessel. Using nominal operating pressure, the vessel is maintained within it's brittle fracture prevention criteria. This difference in test pressure between design pressure and nominal operating pressure could set a precedent for performing the Class 2 and 3 tests at a lower pressure. But the standard argument against this, has been that the lower pressure is off set due to the scope of nondestructive examinations (NDE) required by both Section III and XI on Reactor Vessel and Class 1 systems. An NDE option will be discussed later.

The main point that the reader should get from this section is the pressure test is performed to find through-wall leaks.

CLASS 3 SYSTEM SAFETY CLASSIFICATION

Review of the Nuclear Regulatory Commission's (NRC), Regulatory Guide 1.26, "QUALITY GROUP CLASSIFICATIONS AND STANDARDS OF WATER, STEAM, AND RADIOACTIVE WASTE CONTAINING COMPONENTS OF NUCLEAR POWER PLANTS", Revision 3, 1976, and found plant systems are classified into four safety categories. This review was performed to get an idea of the types of systems that classified as Class 3. Most Class 3 (Category C) systems were found to be low temperature (<200^{0}F) and low pressure (<200 psi). The only exception would be auxiliary feedwater or injection type systems.

The Class 3 systems that have design temperatures under 200^0 F would require the hydrostatic test pressure to be only 10% over the Design Pressure. This category system was the main concern of the first Task Group because there was such a difference between the design versa the operating pressure.

For example a Service Water System with a design pressure of 150 psi would require a hydrostatic test pressure of 165 psi, but operates a pressure of 80 psi (would be the inservice test pressure). This would be in contrast to a Class 2 system with a design pressure of 1500 psi and operates at 1300 psi.

Because of this difference in test pressure concern was expressed that the leakage would be hard to see. Attachment 1 provides the reader a comparison of the leakage flow rates at different test conditions, system pressure only increases the leakage flow rate.

The main point the reader should get out of this section is that the any thing the elevated test pressure provides is a greater leak rate if there is a through-wall flaw.

IMPACT TESTING AND ADDITIONAL NDE TESTING

One of the issues left from the first TG was how is the Class 3 system constructed, including materials and fabrication methods used. Particular concern was express about impact testing of materials. This concern was due to the very low temperatures encountered by some Class 3 system. In order to address this concern the TG reviewed past changes and current requirements of ND-2000 to access the current impact testing requirements and construction rules.

Attachment 2 presents the changes to Section III, ND-2300 and ND-2500 and ND-6000, from the 1972 Winter Addenda to the 1989 Edition of the Boiler and Pressure Vessel Code. From this review the Task Group concluded that no additional testing requirements were needed.

Next the construction codes were reviewed and found that the allowable stress used is temperature dependent for Section III this temperature collation goes down to "-20 - 100^{0}F which should be adequate for a Class 3 Service Water System. B 31.1 also had a methods which factored in a stress for a piping system that would see service at a low temperature.

The TG then reviewed Section XI requirements for Class 3 systems. This review focused on the possible additional of NDE for Class 3 systems as an alternative to performing the hydrostatic pressure test. The TG found that placing a NDE exam requirement on a Class 3 system as an option to the hydrostatic test would not be used by the Owner due to cost. While cost can not or should not be equated to safety. The cost involved with preparing welds and components for NDE examinations would be more than the hydrostatic pressure test. Because of this the addition of NDE was not pursued by the TG.

HISTORY OF FAILURES FOUND DURING HYDROSTATIC TESTING

The last issue to be reviewed was the review of failures (leaks) detected as a result of implementing current Code requirements. Searches were conducted to determine what information was available to build a database. After review of data from the NRC, INPO, and industry surveys the Task Group that there was no enough data to build this base.

Two of the searches produced some interesting results and are noted here. The first is a survey conducted by Mr. J. Leason (Northeast Utilities) and the second is from the INPO NPRDS data base.

In 1990, J. Leason (Northeast Utilities) conducted a Utility survey on various topics which involve hydrostatic pressure tests. The results of the 41 Utilities who responded found that only a very small percentage of these tests found leakage that would not have been found using the system leakage test. Presented as Attachment 3 the survey also addressed questions involving Repairs and Replacements.

There were several other surveys from utilities but trying to determine the type of pressure test used proved to be impossible. This was due to in most cases the pressure test being called a "hydrostatic test" when from the data an inservice test was run. This is especially true of the INPO data base.

The INPO data base identified 25 failures, not a great deal information, but in most cases identified all pressure tests as hydrostatic pressure tests. There was no way to determine if a leakage or hydrostatic test had been performed to find the leak. In some cases a pressure test was not used, the leaks were found by leak detection systems or radiation monitors. While the information selection and collection was not within scientific guidelines, it was interesting to note the components that were identified as having leaks.

CONCLUSION

The performance of the Interval hydrostatic pressure test of Class 3 components places a requirement on the utilities with little benefit. It has been shown that a hydrostatic test only increases the leakage rate from that of a leakage test run nominal operating pressure. Review of industry data, material and construction requirements concerning Class 3 systems supports this position. Therefore, the alternative rules of Code Case N-498, revised to include Class 3, provide an option which provides a reasonable requirement that produces the desired results.

NPDRS DATA

COMPONENTS	NUMBER		PER CENT	
Heat Exchangers	18		72%	
Steam Generator (tubes)		9		36%
Cooling Coils (tubes)		7		28%
Feed Water		2		8%
Pipe	5		20%	
Service Water		3		12%
Class 1		2		8%
Vessel	1		4%	
SI Accumulator		1		4%
Valve	1		4%	
Body		1		4%
Total	25			

REFERENCES

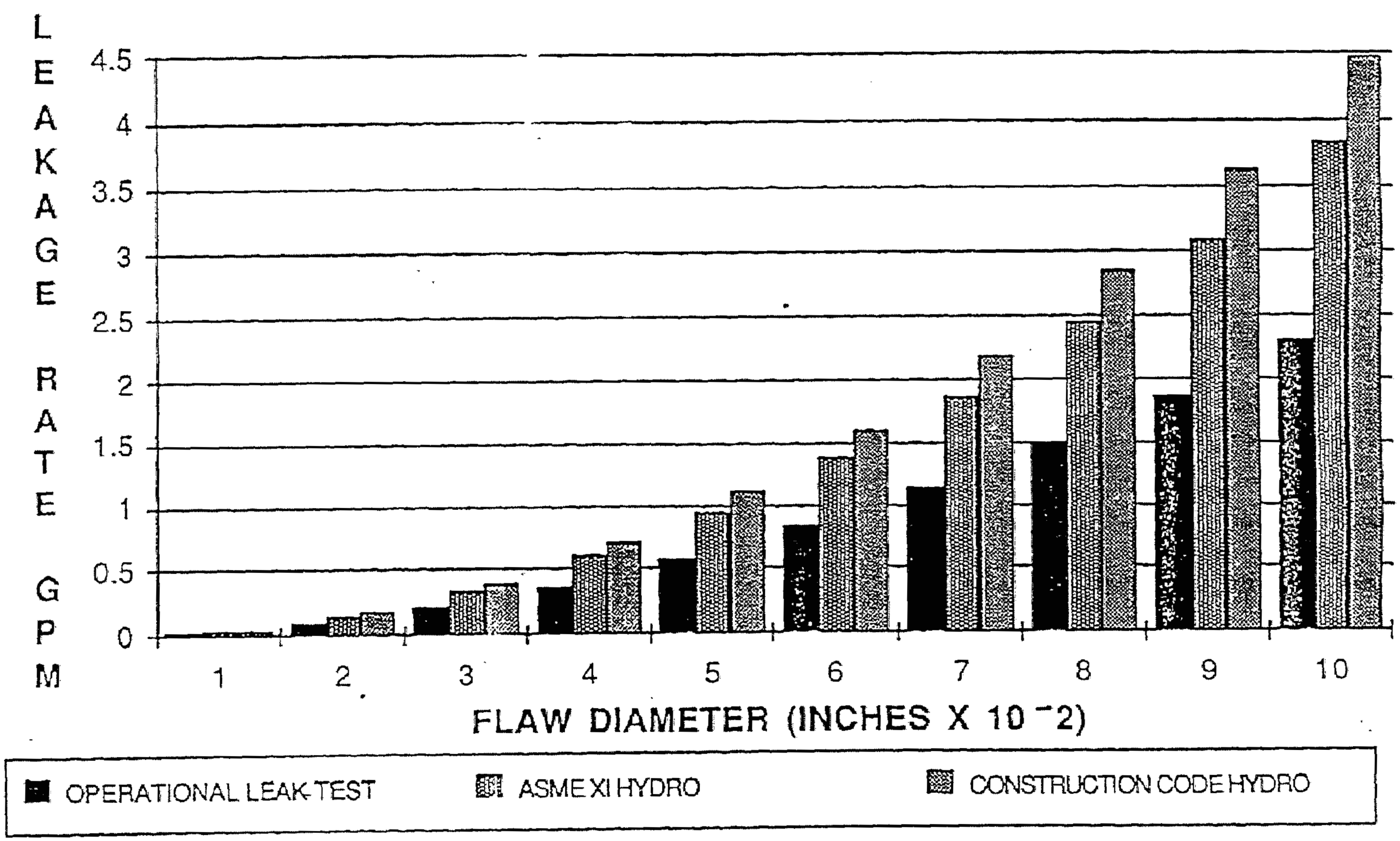
1. Gosslin, S., "Inservice Inspection Pressure Testing in Class 1,2, and 3 Systems", December 10, 1990.

2. Bush, S. H. and Maccary, R. R., Development of Inservice Inspection Safety Philosophy for U.S. Nuclear Plants.

3. Nuclear Regulatory Commission's (NRC), Regulatory Guide 1.26, "QUALITY GROUP CLASSIFICATIONS AND STANDARDS OF WATER, STEAM, AND RADIOACTIVE WASTE CONTAINING COMPONENTS OF NUCLEAR POWER PLANTS", Revision 3, 1976;

4. Leason to Schaaf, May 20, 1990, Memo 90020, Hydro Survey Results and Leakage Rates

SERVICE WATER EROSION / CORROSION



ATTACHMENT 1

066

EROSION / CORROSION LEAKAGE RATES

SYSTEM SERVICE WATER SAFETY CLASS 3

PIPE SIZE 1" SCHEDULE 40 WALL 'T' .133"

MATERIAL A 106 GR B CS DESIGN PRESSURE/ TEMP 150 PSIG / 100 F

OPERATIONAL LEAK PRESSURE / TEMP:	ASME XI HYDRO PRESSURE / TEMP:	CONSTRUCTION CODE HYDRO PRESSURE / TEMP
60 PSIG / 70 F	165 PSIG / 70 F	225 PSIG / 70 F

LEAKAGE RATES (GPM)

FLAW DIA. (INCHES)	OPERATIONAL LEAK TEST	ASME XI HYDRO	CONSTRUCTION HYDRO
.01	.0231	.0383	.0448
.02	.0925	.1534	.1792
.03	.2082	.3453	.4033
.04	.3702	.6139	.7169
.05	.5785	.9593	1.1202
.06	.8330	1.381	1.6132
.07	1.1338	1.8801	2.1957
.08	1.4809	2.4556	2.8679
.09	1.8743	3.1079	3.6297
.10	2.314	3.837	4.4811

ATTACHMENT 2

SUMMARY OF CHANGES

ASME SECTION III

CLASS 3

CODE EDITION	IMPACT TESTING (ND-2300)	NDE REQUIREMENTS (ND-2500)	PRESSURE TESTING (ND-6000)
WINTER 72	-No significant changes	-size requiring exam changed from 4" to 2"	-No significant changes
SUMMER 72	-impact testing revised in its entirety -test specimens and orientation of impact test specimens -added requirements and acceptance standards -replaced C_v values of Appendix I w/new table and values -materials exempt from 1/2" thick to 5/8" thick	-No significant change	-No significant change
WINTER 72	-No significant changes	-UT, RT, ET, must cover entire volume of part -method used to examine repair must be method that detected flaw -allowance for P1/P12A material to be examined by MT/PT before PWHT (material 2" and less)	-No significant changes

SUMMER 73	-added requirements for bolting material -changed test temperature on bolting material -impacts separated into Charpy V-Notch and Drop Weight -Drop Weight test not required for martensitic high alloy Chromium Steels -added orientation requirements for Drop Weight Test -changed retest requirements	-No significant changes	-No significant changes
WINTER 73	-No significant change	-increased scope of exam from "cast pressure retaining material" to products -deleted details from angle beam method reference to T-524 Section V, Art. 2 added	-No significant change
WINTER 74	-added requirements for pressure retaining material with 2-1/2" max. thickness	-material less than 3/8" changed to material less than 5/8"	-No significant change
WINTER 75	-No significant change	-added SA-134 tubular products -RT added	-No significant change
WINTER 76	-added precipitation hardening steels to materials requiring impact testing	-No significant change	-No significant change

SUMMER 77	-No significant change	-added requirements exam/repair of wrought seamless and welded tubular products and fittings and pipe and tube -time of exam deleted -added requirements for copper and nickel alloy seamless piping and tubing -added requirements for wrought seamless and welded fittings -add exam for SA-135) SA-155) SA-358) SA-409) tubular product SA-671) SA-672) SA-234) SA-403) fittings SA-420) -extended methods and acceptance standards -deleted reference to ASTM E-71-64 -acceptance requirements of severity level 2 -revised E-280-68 to E-280-72	-No significant change
SUMMER 78	-added Materials exempt from impact testing -added exemptions for impact testing -orientation of impact test specimens revised specimens axis orientation deleted	-SA-691 added to tubular products	-option of using water or service fluid as test medium

	-C_v values for bolting revised		
WINTER 78	-required C_v values for pressure retaining material revised	-revised to include pressure retaining material for ANSI B16.34	-deleted testing relief valves
WINTER 79	-revised the C_V values for pressure retaining material	-revised extent, methods and acceptance standards -revised references to ASTM's -RT exam revised ASTM E-186 was changed to reference the 78 editions -RT exam revised ASTM E-446-72 change to E-446-78	-revised options for using pneumatic testing* *25 psi changed to 25% of the design pressure
SUMMER 80	-No significant change	-exam/repair of cast products (statically /centrifugally) added that cast products shall meet all requirements of SA-613	-No significant change
WINTER 80	-No significant change	-material SA-15 deleted	-No significant change
SUMMER 81	-No significant change	-No significant change	-hydro tests required on all equipment except tanks -holding time requirements added provisions for pumps/valves -revised to include rules for minimum pneumatic test pressure for valves -added test pressure holding time
SUMMER 82	-design spec. should specify lowest service temperature -revised retest requirements	-No significant change	-No significant change

ADDENDA 86	-No significant change	-Pressure retaining material and materials welded to require examination by NDE -added time of examination criteria for MT, PT, of forged and rolled bars -added VT for bolting materials	-No significant change

ATTACHMENT 3

SURVEY RESULTS

CLASS 2 and 3 HYDROSTATIC PRESSURE TESTS

1. Has leakage ever been detected during a Class 2 or 3 10-Year Hydro on the following?
   (A) Stainless steel butt welded joints? Y=0, N=32, ?=9.
   (B) Carbon steel butt welded joints? Y=1, N=31, ?=9.
   (C) Stainless steel socket welded joints? Y=3, N=29, ?=9.
   (D) Carbon steel socket welded joints? Y=2 , N=30, ?=9
   (E) Brazed joints? Y=5, N=27, ?=9.

2. Has leakage ever been detected during a Class 2 or 3 Repair/ Replacement Hydro on the following?
   (A) New stainless steel butt welded joints? Y=0, N=39, ?=2.
   (B) New carbon steel butt welded joints? Y=0, N=41.
   (C) New stainless steel socket welded joints? Y=0, N=41
   (D) New carbon steel socket welded joints? Y=1, N=40
   (E) New brazed joints? Y=3, N=35, ?=3.

3. Has leakage ever been detected on Class 2 or 3 piping or components due to erosion or corrosion during a 10-Year Hydro (i.e. service water)? Y=15, N=23, ?=3.

4. Has leakage ever been detected on closed cooling water systems that have chemical additives (hydrazine) to inhibit corrosion? Y=4, N=32 ?=5.

5. Have there ever been any personnel injuries associated with hydrostatic pressure testing? Y=2, N=37, ?=2.

6. Do you have to take systems out of service, drain them and remove relief valves and install blank flanges for hydros? Y=37, N=3, ?=1.

7. Would you receive more personnel radiation exposure during a Class 2 or 3 hydro than what you would if an Inservice Leakage Test were performed? Y=32, N=6, ?=3.

8. Do you have to rework valve body seats on valves where seat leakage is inconsequential during normal operation in order to achieve a successful Hydro? Y=24, N=13, ?=4.

9. Do Class 2 and 3 hydros take up critical path outage time?
Y=26, N=10, ?=5.

10. Do you have to use additional personnel other than what you normally staff in order to perform Class 2 or 3 hydros?
Y=33, N=4, ?=4.

11. Should the Class 2 or 3 hydrostatic test pressure (1.1 or 1.25 times system design or relief valve setting) be lowered to a pressure just above normal system operating pressure? Y=27, N=12, ?=2.

12 Would a Class 2 or 3 Inservice Leakage Test performed every outage or every inspection period at normal system operating pressure and temperature suffice in lieu of a 10-Year required Class 2 or 3 Hydro? Y=39, N=2 ?=1.

13. Would an Inservice Leakage Test performed at normal system operating pressure and temperature suffice in lieu of a hydro when welded repairs or replacements are performed?
Y=29, N=11, ?=1.

14. Should Repair/Replacement Hydros be eliminated from the Code if a full volumetric examination (UT or RT) for full penetration welds or if a surface examination (PT or MT) for partial penetration welds is performed after welded Repairs or Replacements?
Y=31, N=9, ?=1.

15. Should a Class 2 or 3 10-Year hydro be used in lieu of a Repair/Replacement Hydro? (Ref: Code Case N-416 "Alternate Rules for Hydrostatic Testing of Repair or RePlacement of Class 2 Piping."). Y=18, N=21, ?=2.

16. Should Class 2 or 3 10-year required Hydros be eliminated from the Code entirely? Y=35, N=5 ?=1.

17. Should Class 2 or 3 Repair/Replacement Hydros be deleted from the Code Entirely? Y=22, N=18, ?=1.

18. Should hydrostatic pressure tests be left at the Owners' discretion as an option? Owner=20, Code=15, ?=6.

19. Should the VT-2 required certification be deleted from the Code so that Operations or Maintenance Department Personnel can perform the visual examination in lieu of a qualified VT-2 examinator? **Y=19, N=22.**

20. Do you concur with the present Section XI Hydrostatic Pressure Test Rules and Requirements for Class 2 and 3 systems? **Y=1, N=39, ?=1.**

21. Do you concur with the present Section XI Leakage Test Rules and Requirements for Class 2 and 3 systems? **Y=19, N=22.**