June 23, 2005

Mr. D. M. Jamil
Vice President
Catawba Nuclear Station
Duke Energy Corporation
4800 Concord Road
York, SC 29745

SUBJECT: CATAWBA NUCLEAR STATION, UNITS 1 AND 2 RE: REQUEST FOR RELIEF 04-CN-004, PRESSURE REQUIREMENT AT CERTAIN CLASS 1 INSERVICE INSPECTION PRESSURE TEST BOUNDARIES (TAC NOS. MC3276 AND MC3277)

Dear Mr. Jamil:

By letters dated May 18, 2004, January 27 and May 16, 2005, Duke Energy Corporation, the licensee for Catawba Nuclear Station (Catawba), Units 1 and 2, submitted a request for relief, Relief Request No. 04-CN-004, from the American Society of Mechanical Engineers (ASME), Boiler and Pressure Vessel Code, Section XI, 1989 Edition requirement of Paragraph IWB-5221(a). This paragraph mandates performance of a system leakage test at a test pressure equivalent to the nominal operating pressure associated with 100 percent rated reactor power for certain Class 1 piping segments connected to the Reactor Coolant System. The licensee's proposed alternative is to perform the system leakage test at a test pressure corresponding to the operating pressure of the component.

The enclosed Safety Evaluation contains the Nuclear Regulatory Commission (NRC) staff's evaluation and conclusions. Based on the information provided in the relief request, the NRC staff has determined that for these portions of the Class 1 boundary, compliance with the ASME Code as stated in Paragraph IWB-5221, used in conjunction with ASME Code Case N-498-1 with regard to the required pressure during the system leakage test, would result in hardship or unusual difficulty without a compensating increase in the level of quality and safety.

The NRC staff concludes that the licensee's proposed alternative test pressures provide reasonable assurance of leak tightness and structural integrity of the subject portions of piping. Furthermore, the subject segments of piping receive a volumetric examination, surface examination, or both, in accordance with ASME Code requirements which provide additional assurance of leak tightness and structural integrity of the subject segments of piping.

Therefore, pursuant to Title 10 of the *Code of Federal Regulations*, Section 50.55a(a)(3)(ii), the licensee's proposed alternative is authorized for Catawba Nuclear Station, Units 1 and 2 for the second 10-year inspection interval. All other requirements of the ASME Code, Section III and XI for which relief has not been specifically requested remain applicable, including third party review by the Authorized Nuclear Inservice Inspector.

Sincerely,

/RA/
Evangelos C. Marinos, Chief, Section 1
Project Directorate II
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket Nos. 50-413 and 50-414

Enclosure: As stated

cc w/encl: See next page

Therefore, pursuant to Title 10 of the *Code of Federal Regulations*, Section 50.55a(a)(3)(ii), the licensee's proposed alternative is authorized for Catawba Nuclear Station, Units 1 and 2 for the second 10-year inspection interval. All other requirements of the ASME Code, Section III and XI for which relief has not been specifically requested remain applicable, including third party review by the Authorized Nuclear Inservice Inspector.

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OFFICIAL RECORD

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

REQUEST FOR RELIEF NO. 04-CN-004

CATAWBA NUCLEAR STATION, UNITS 1 AND 2

DUKE ENERGY CORPORATION

DOCKET NOS. 50-413 AND 50-414

1.0 INTRODUCTION

By letters dated May 18, 2004, January 27 and May 16, 2005 (Agencywide Documents Access and Management System (ADAMS), Accession Nos. ML041490116, ML050890117, and ML051440365), Duke Energy Corporation, the licensee for Catawba Nuclear Station (Catawba), Units 1 and 2, submitted a request for relief, Relief Request No. 04-CN-004, from the American Society of Mechanical Engineers (ASME), Boiler and Pressure Vessel (B&PV) Code, Section XI, 1989 Edition requirements of Paragraph IWB-5221(a) for the second 10-year interval inservice inspection (ISI). Paragraph IWB-5221(a) mandates performance of a system leakage test at a pressure equivalent to the nominal operating pressure associated with 100 percent rated reactor power for certain Class 1 piping segments connected to the reactor coolant system (RCS).

2.0 REGULATORY EVALUATION

Licensees perform ISI of the ASME B&PV Code Class 1, 2, and 3 components in accordance with Section XI of the ASME Code "Rules for Inservice Inspection of Nuclear Power Plant Components," and applicable addenda as required by Title 10 of the *Code of Federal Regulations* (10 CFR) Section 50.55a(g), except where specific relief has been granted by the Nuclear Regulatory Commission (NRC) pursuant to 10 CFR 50.55a(g)(6)(i).
10 CFR 50.55a(a)(3) states that alternatives to the requirements of paragraph (g) may be used, when authorized by the NRC, if: (i) the proposed alternatives would provide an acceptable level of quality and safety or (ii) compliance with the specified requirements would result in hardship or unusual difficulty without a compensating increase in the level of quality and safety.

Pursuant to 10 CFR 50.55a(g)(4), ASME Code Class 1, 2, and 3 components (including supports) shall meet the requirements, except the design and access provisions and the pre-service examination requirements, set forth in the ASME Code, Section XI to the extent practical within the limitations of design, geometry, and materials of construction of the components. The regulations require that ISI examination of components and system pressure tests conducted during the first ten-year interval and subsequent intervals comply with the requirements in the latest edition and addenda of Section XI of the ASME Code incorporated by reference in 10 CFR 50.55a(b) 12 months prior to the start of the 120-month interval, subject to

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the limitations and modifications listed therein. The applicable ASME Code of record for the second 10-year ISI interval for Catawba Nuclear Station, Units 1 and 2 is the 1989 Edition of the ASME B&PV Code, Section XI. The Catawba Nuclear Station, Unit 1 second 10-year ISI interval began on June 29, 1995, and ends on June 29, 2005. For Catawba Nuclear Station, Unit 2 the second 10-year ISI interval began on August 19, 1996, and ends on August 19, 2006.

3.0 TECHNICAL EVALUATION

3.1 ASME Code Component Affected

Systems Designation Legend:
NC - Reactor Coolant System (or RCS)
NV - Chemical Volume and Control System
ND - Residual Heat Removal System [(RHR)]
NI - Safety Injection System
WL - Liquid Waste Recycle System

Relief is requested for portions of ASME Code Class 1 piping and components connected to the RCS that are normally isolated from direct RCS pressure (2235 [pounds per square inch gauge] psig) during their normal operation. They are isolated from the reactor coolant loop by their location, either upstream of a check valve, between 2 check valves or between 2 closed valves that must remain closed during the unit's operation (or Startup) in Modes 3, 2 or 1. The specific portions of piping for which relief is requested are described below.

Note: Valve/component numbers (even where unit numbers are listed) correspond for both units 1 and 2.

Portion 1: 2 inch NV Class 1 piping and components upstream of Auxiliary Spray inboard check valve NV-38 up to and including outboard RCS isolation valves NV-37A (globe valve) and NV-861 (check valve).

Portion 2: 12 inch and 3/4 inch Class 1 piping and components on the ND Suction line between the RCS double isolation gate valves 1ND-1B and 1ND-2A (A Train ND suction) and Valves ND-36B and ND-37A (B Train ND suction) up to and including their gates.

Portion 3: On each of the 4 RCS loops, 1½ inch NI Class 1 piping and components between double isolation check valves (and including the second isolation check valves) for NC Cold Leg Boron Injection. Double isolation check valve pairs are:

NI-15 and NI-351 for Loop A
NI-17 and NI-352 for Loop B
NI-19 and NI-353 for Loop C
NI-21 and NI-354 for Loop D

Portion 4: On each of the 4 RCS loops, 10 inch, 6 inch, 2 inch, 1 inch, and 3/4 inch NI Class 1 Cold Leg Injection Piping and components upstream of the 10 inch RCS isolation check valves, and going back to and including the following:

a.) Cold Leg Accumulator (CLA) isolation "block valve" (gate valve), 1 inch, and 3/4 inch piping flow element and vent valves, AND

b.) NI pump and ND pump discharge isolation check valves (and associated 3/4 inch piping):

NI-171 and NI-175 for Cold Leg C,
NI-169 and NI-176 for Cold Leg D,
NI-167 and NI-180 for Cold Leg B,
NI-165 and NI-181 for Cold Leg A

Portion 5: 8 inch, 6 inch, 4 inch, 2 inch and 3/4 inch Class 1 piping and components in the Safety Injection (NI) System up stream of the Hot Leg Injection isolation check valves NI-157, NI-134, NI-126 and NI-160 (for Hot Legs A, B, C, and D respectively) and back to and including the following:

a.) NI pump B discharge isolation check valve NI-156 and associated 3/4 inch line with flow restrictor (for Hot leg A).

b.) NI Pump A discharge isolation check valve NI-128 and ND Pump(s) discharge isolation check valve NI-129 and associated 3/4 inch line with flow restrictor (for Hot leg B).

c.) NI Pump A discharge isolation check valve NI-124 and ND pump(s) discharge isolation check valve NI-125 and associated 1/4 inch line with flow restriction (for Hot Leg C).

d.) NI Pump B discharge isolation check valve NI-159 and associated 3/4 inch line with flow restrictor (for Hot Leg D).

Portion 6: 2 inch NC Class 1 piping and components between (and including) double isolation globe valves isolating NC Loop from WL system piping routed to Reactor Coolant Drain Tank Pump (One segment is on each of 4 Loops). Segment boundaries are:

NC-4, NC-5 and Flow Restrictor for Loop A,
NC-94, NC-95 and Flow Restrictor for Loop B,
NC-13, NC-106 and test drain NC-115 for Loop C,
NC-19, NC-20, and test drain NC-111 for Loop D.

Portion 7: The 3/4 inch, 1 inch, and 3 inch NC Class 1 piping between (and including) the following RCS double isolation valve pairs on the Reactor Vessel Head vent line:

NC-298 and NC-299, (3 inch)
NC-311 and NC-312, (3/4 inch)
NC-250A, NC-251B, NC-252B, and NC-253A, (1 inch)

3.2 Applicable ASME Code Requirement

The 1989 Edition of the ASME B&PV Code, Section XI, Table IWB-2500-1, Examination Category B-P; Item No. B15.51, Class 1 piping system hydrostatic test, to be conducted once either at or near the end of each Inspection Interval. (Reference Table [IWB-2500-1] Note 6[1]).

Code Case N498-1: Alternative Rules for 10-year System Hydrostatic Testing for Class 1, 2 and 3 Systems. Section XI, Division 1:

(a) It is the opinion of the Committee that as an alternative to the 10 year system Hydrostatic test required by Table IWB-2500-1, Category B-P, the following rules shall be used.

(1) A system leakage test (IWB-5221)* shall be conducted at or near the end of each inspection interval, prior to reactor startup.

(2) The boundary subject to test pressurization during the system leakage test shall extend to all Class 1 pressure retaining components within the system boundary.

(3) Prior to performing the VT-2 visual examination, the system shall be pressurized to nominal operating pressure for at least 4 hours for insulated systems and 10 minutes for non-insulated systems. The system shall be maintained at nominal operating pressure during performance of the VT-2 visual examination.

(4) The VT-2 visual examination shall include all components within the boundary identified in (a)(2) above.

*IWB-5221 System Leakage Test

(a) The system leakage test shall be conducted at a test pressure not less than the nominal operating pressure associated with 100% rated reactor power.

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1. Table Note 6 refers to the ASME Code, Section XI, Table IWB-2500-1, Category B-P which states: The system hydrostatic test (IWB-5221) shall be conducted prior to plant startup following each reactor refueling outage.

The application of the above ASME Code requirements, along with those of Code Case N-498-1, would require Class 1 piping, that either at or near the end of each 10-year ISI Interval, a system leakage test be performed that would extend a test pressure equal to the nominal operating pressure associated with 100% rated reactor power (i.e., 2235 psig) to all Class 1 pressure retaining components connected to the Reactor Coolant System (RCS).

3.3 Licensee's Code Relief Request

In accordance with the requirements of 10 CFR 50.55a(a)(3)(ii), relief is requested from the '89 [1989] ASME Section XI Code requirement of Par. [Paragraph] IWB-5221(a) that mandates performance of a system leakage test at a test pressure equivalent to the nominal operating pressure associated with 100% rated reactor power (i.e. 2235 psig) for certain Class 1 piping connected to the RCS.

Specifically, relief is requested from the requirement to extend 2235 psig as a test pressure (for holding time and VT-2 examination) to certain portions of ASME Code Class 1 piping and components connected to the RCS, that are normally isolated from receiving direct RCS pressure (2235 psig) during their normal operation for the unit. These portions of piping are isolated from the reactor coolant loop piping by their location either upstream of a check valve, between 2 check valves or between 2 closed valves that must remain closed during the unit's operation (or Startup) in Modes 3, 2 or 1 when RCS pressure is either at or approaching 2235 psig.

3.4 Licensee's Proposed Alternative

Discussions with [the Duke Energy Corporation] Civil/Structural Engineers and Systems Engineers concerning Reduced Pressure Testing of piping for visible "through wall" leakage [the engineers] agreed that through wall leakage that would occur at higher pressures such as RCS pressure would also reveal itself at lower pressures when a significant "reduced pressure ratio" exists for the reduced pressure used. It may take longer for some leaks to propagate through the piping wall at lower pressures, but generally, during reduced pressure testing, the resulting leak rates would be reduced, but the leakage would still be visible to VT-2 examination.

In support of this, [Duke Energy Corporation] Engineering revealed that leakage through a fixed area orifice varies proportional to the square root of the ratio ofthe differential pressures (ref. CRANE Technical Paper #410[2]). For example, if a leak L were projected to be present at 2235 psig, that same leak would be present at 250 psig, but with a magnitude of

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2. The Crane Technical Paper No. 410 is published by Crane Valve Company of Signal Hill, Ca and is not included in this safety evaluation. For a fee the Crane Technical Paper No. 410 may be purchased from the Crane Valve Company of Signal Hill, Ca.

$$\sqrt{\frac{250}{2235}}xL = .33L$$

Inspections that reveal <u>no leakage</u> at 250 psig (where 33% of the leakage produced by 2235 psig pressures would be present for detection during VT-2 examination) therefore give high confidence that no leakage would be present at 2235 psig.

The pressure values used in the reduced pressure testing performed as alternative pressure tests for [Catawba] unit 1 that are covered in this request for relief, range from 250 psig to $800 psig, except for Portion 6 and 7 where actual pressure is unknown. Pressures that range from approximately 250 psig to $800 psig are sufficient to provide for the detection of any through wall leakage in the tested piping and components during the performance of the alternative tests.

Therefore, pursuant to the 10 CFR 50.55a(a)(3)(i) requirement, the pressure tests and VT-2 examinations performed at the lower pressures indicated in the following alternative pressure tests are determined to provide an acceptable level of assurance of the quality, safety and structural integrity of the tested piping.

The [Catawba] Unit 2 piping for all Portions will undergo the same alternative testing as was performed for the Unit 1 piping as described above.

<u>Portion 1 - Alternative testing:</u>

During [Catawba] Unit Shutdown an alternative test will be performed on the Portion 1 piping in accordance with the requirements of [ASME] Code Case N-498-1 for ISI Pressure Testing of Class 1 piping, except that the alternate (lower) pressure will be used as opposed to RCS operating pressure of 2235 psig., for both the 4 hour hold time and the VT-2 examination. Test will be done with auxiliary spray from RHR inservice. Expected pressure is 250-350 psig.

Later in the Start-up process, the piping will be VT-2 examined again with the RCS in its normal alignment and at full temperature and pressure (after a 4 hr hold time) during the 10 year Class 1 Leakage Test performed per [ASME] Code Case N-498-1 during Startup.

<u>Portion 2 - Alternative Testing:</u>

ND suction piping operating pressure is subject to the following restrictions:

a.) The open permissive for ND-1B and 2A and ND-36B and ND-37A is < 425 psig.

b.) Relief valve ND-3 and ND-38 has a nominal lift set point of 450 psig.

c.) ND Operating Procedures limit NC pressure to less than 385 psig.

As a practical operating pressure, ND suction is nominally maintained at 325 psig when NC is pressurized.

Since 325 psig is considered to be the typical operating pressure, an alternative test pressure of 325 psig (for hold time and VT-2 examination for leakage) fulfills the same purpose as the test pressure required by ’89 ASME Section XI, Paragraph IWB-5221 by checking for component leakage at pressures equaling the typical operating pressure of the tested piping.

Portion 3 - Alternate Testing:

During a refueling outage, this piping can be pressurized and VT-2 examined running an ND pump "piggy back" to the Centrifugal Charging (NV) Pump aligned to all four cold legs, which provides a minimum pressure of 800 psig at the NV pump discharge. The piping between the check valves would see pressure <800 psig due to piping losses and throttle valve pressure drop.

However, pressures greater than 800 psig can be (and have been) applied to this piping using other sources for the test pressure. For example, residual leakage past any one of the pairs of check valves can result in pressures >800 psig on the back side of all 4 of the check valve pairs. However, such "other sources" are not always repeatable.

This alternate testing uses pressures for hold times and VT-2 examinations $800 psig, which are sufficient to provide for detection of any through wall leakage and provides an acceptable level of assurance in structural integrity of the piping.

Portion 4 - Alternative testing:

During unit startup, the Portion 4 piping is expected to see pressures in the range of 600 psig for > 4 hours. These pressures reflect those seen by this piping during it's normal operation.

585 psig is the minimum pressure each Portion 4 segment of piping will see when the CLAs are required to be operable per the Tech Spec [Technical Specification] 3.5.1 requirement.

During [Catawba] Unit Start-up, an alternative pressure test and VT-2 examination will be performed on the Portion 4 piping in accordance with the requirements of [ASME] Code Case N-498-1 for ISI Pressure Testing of Class 1 piping, except that the alternate (lower) pressure of 585 psig will be used for both the 4 hour hold time and the VT-2 examination.

Portion 5 - Alternative testing:

The alternative pressure test of the Portion 5 piping can be performed in the unit startup process during the Pressure Isolation Valve (PIV) testing performed per Tech. Spec Surveillance Requirements.

The Portion 5 piping is not insulated, so both the hold time requirement of 10 minutes and the VT-2 examination can be performed at the alternate test pressure while the testing engineer "holds" the back side check valve "set" pressure for the time required for hold time and VT-2 examination.

Testing of the Unit Portion [5] piping will be performed in this manner during unit Start-up. Hold time and VT-2 examination pressure will be approximately 327 psig.

<u>Portions 6 & 7- Alternate Testing:</u>

The Portion 6 NC piping between valves on double isolation vent and drain assemblies, as well as the Rx [reactor] Head Vent Line valves (listed above) could be pressurized to RCS pressure by opening the inside valve during startup. However, this would be a hardship, encountering similar problems as described in the above discussion [see under ASME Code Component Affected above]. Stationing individuals at these open "inside" RCS isolation valves inside Lower Containment would pose a significant safety hazard and considerably increase radiation exposure to station personnel.

Regarding use of a hydro pump in No Mode [no fuel in reactor vessel], there are 4 piping sections with double isolation vent and/or drain valve assemblies that would have to be tested individually (by hydro pump) during No Mode due to their diverse locations inside Lower Containment. This would result in a substantial increase in radiation exposure to station personnel. For the remaining 3 piping sections, no isolation is possible from either the Reactor Vessel or the Pressurizer Relief Tank without significant modification, and no connections exist between the valve pairs for connection, testing of the Reactor Head vent pipe by hydro pump or temporary jumper is not possible.

Duke Power Company (CNS) [Catawba Nuclear Station] proposes as an acceptable alternative test, the VT-2 examination of the Portion 6 and 7 piping by VT-2 qualified QC [Quality Control] Inspectors after the piping has undergone a 4 hour hold time with the NC system at RCS pressure and temperature (2235 psig @ 557 EF.) with all affected double isolation valves and test/drain valves in their normal operating position (closed). Duke believes the through-wall integrity of the Portions 6 and 7 piping under its normal operating conditions is adequately tested/verified by this VT-2 examination after a 4 hour hold time at RCS pressure, and that incurring the previously listed dosage, personnel hazards and risks in order to apply and verify RCS pressure (2235 psig) on this piping for 4 hours prior to VT-2 examination, would pose a hardship for the station.

<u>Licensee’s Basis for Relief Request</u>

The following discussion provides the basis for the requested relief and approval of the proposed alternative testing in accordance with the provisions in 10 CFR 50.55a(a)(3)(ii) due to the hardship that would be imposed by complying with the Code requirement.

Applying RCS operating pressure (2235 psig) to Portions 1, 2, 3, 4, 5, 6, and 7 of the Class 1 piping listed in Section I[3] of this document would result in a hardship by exposing station personnel to:

- personal safety hazards ranging from immediate physical exposure to temporary connections whose medium is pressurized to 2235 psig (and in some cases at 557 EF. temperature) to their being "stationed" at opened manual valves in Lower Containment at or near vent/drain valves serving as RCS single isolation pressure and temperature barriers in order to maintain the RCS boundary redundant valve protection requirement of 10 CFR 50.55a(c)(ii) during the test

- additional radiation exposure from activities in Lower Containment such as transporting, connecting, performing testing activities with, and removing hydro pump or temporary jumper materials; scaffold erection and tear down where needed; insulation removal and replacement where needed; valve internals removed and replaced where needed; and valve gags installed and removed where needed. Unknown delays in any of these activities could occur in Lower Containment, which would increase the additional radiation exposure.

Portion 1

Introducing NC system operating pressure (2235 psig) to the Portion 1 piping upstream of the Pressurizer Isolation Check Valve NV-38 during Unit Start-up with NC system at normal operating pressure and temperature would pose a hardship for the station because of the high risk of an Inadvertent Pressurizer Auxiliary Spray Initiation to the pressurizer at normal NC system operating temperature and pressure. This "Upset Condition" design transient (defined in UFSAR Section 3.9.1.1) is undesirable for the following reasons.

1.) It would force static piping "cold water" contents into the pressurizer spray line and result in an additional thermal design cycle. The plant design only allows for 10 of these over the plant design life (ref. UFSAR Table 3.50 "Design Transients for ASME Code Class 1 Piping").

Portion 2

Opening ND-1B or ND-36B during RCS pressurization to pressurize the Portion 2 piping would pose a hardship for the station because it would breach the 10 CFR 50.55a(c)(ii) required double isolation valve barrier of the RCS boundary from the ND system. This would create an inability to mitigate a Loss Of Coolant Accident (LOCA) if a break was to occur in the 12 inch piping between valves ND-1B and ND-2A, ND-36B , and ND-37A, reducing the plant's margin of safety. Valve ND-1B or ND-36B could not be counted on to close against the postulated flow from the RCS through a 12" [inch] line break. It

3. Section I is contained in the licensee's submittial dated May 18, 2004 and is reproduced in Section 3.1 of this report.

would also subject ND system components to risk of damage with only a single valve isolation from RCS pressure.

Portion 3

On the Portion 3 piping, no intermediate test connection exists on the 3 inch segment of pipe between these check valve pairs to measure the test pressure locally. Aligning an NV Pump to the Boron Injection flow path in Mode 3 (at startup) and cracking open valve NI-3 would constitute a Manual Safety Injection, counting against the allowed Cold Leg Thermal Design Transients (design limit is 50 for the life of the plant). Such action would pose a hardship for the plant. This is also counter-productive to long term piping/weld health. Risking degradation of piping/weld health [i.e., increase the potential for degradation due to thermal fatigue] for the sake of verifying the safety and integrity of that piping is unreasonable.

Portion 4 and 5

Introducing RCS pressure between the PIVs at this time would likely cause the inboard PIV to unseat, placing the station in Tech Spec 3.4.14 LCO Action Condition. The previously completed PIV Leak Rate Test would be voided and Tech Spec action would be required to 1.) isolate the high pressure portion of the affected system from the low pressure portion within 4 hours, AND 2.) perform the PIV Leak Rate Test again within 24 hours AND 3.) restore the RCS PIV to within the leakage limits within 72 hours. It would be ill-advised to expose the unit to such a risk that would likely result in the hardships for the station described above.

The PIV’s serve as the RCS pressure boundary (ref. 10 CFR 50.2 and 10 CFR 50.55a(c)). The limit on allowable PIV leakage rate (discussed above) prevents over pressurization to the low pressure portions of the connecting NI System piping as well as the loss of integrity of a fission product barrier. Failure consequences could be a loss of coolant accident (LOCA) outside of containment, an unanalyzed accident that could degrade the ability of low pressure injection. Note that the 1975 NRC "Reactor Safety Study" (ref. WASH-1400 (NUREG-75/014), Appendix V, October 1975) identified potential intersystem LOCAs as a significant contributor to the risk of core melt.

Using a hydro pump to pressurize Portion 4 or Portion 5 piping during No Mode [no fuel in reactor vessel] would in either case, require all 4 of the inboard NI check valves interfacing the NC system (10" [inch] for Portion 4 and 6" [inch] for Portion 5) be temporarily gagged closed to provide a pressurization boundary. Gagging closed these check valves to hold 2235 psig would pose a substantial risk of damage to the component from the loads that would be transferred to the valve body by a gagging apparatus to hold the valve seat shut for the test. The seat is approximately 6 inches in diameter for both the 10" [inch] and the 6" [inch] valves. The load force against the valve seat at RCS pressure would exceed 63,000 lbs. The geometry of these valve bodies make it difficult to transfer such loads to appropriate areas of the valve body via a gag apparatus.

It would be prohibitive to attempt to use such an apparatus on an ASME Class 1 valve serving as part of the RCS pressure boundary (due to the high risk of damaging the components) without following up with volumetric examination of the valve body. UT [ultrasonic examination] would not suffice (surface contours and nonparallel valve walls), leaving only RT [radiography examination] to employ. Even if each valve tested OK, the extra radiation exposure alone from gagging, testing, reassembling, and performing RT on each valve would constitute a considerable hardship for the station.

<u>Portion 6 and 7</u>

RCS pressure could be applied to the Portion 6 and Portion 7 piping [or both] by opening the "inside" NC loop isolation valves at the onset of NC system pressurization. Each of these valves is the first of a series of two valves maintaining double isolation of the RCS pressure boundary either from other piping or from the containment atmosphere.

Opening these valves to pressure test this piping at RCS pressure would eliminate the double valve protection required by 10 CFR 50.55a(c)(ii) for the RCS boundary, creating a "single valve barrier" between the RCS pressure boundary and non-code piping. The piping on the discharge side of these "single valve barriers" is <u>non-code piping</u>, and not designed to serve as part of the RCS double isolation pressure boundary.

Opening the inner manual isolation valve would constitute a hardship since station personnel would have to be stationed at or near the "opened" valve(s) in Lower Containment with RCS at normal operating pressure. They would be exposed to the personal hazards of occupying a close proximity to the tested piping/components subjected to RCS pressure <u>and temperature</u> (2235 psig at 557 EF.), with a nearby drain valve serving as a single valve RCS pressure isolation barrier.

Since no [test] connections exist between the valve pairs for test connection, testing of the piping between the Reactor Head vent pipe double isolation valves by hydro pump or temporary jumper is not possible.

Duke Power Company (CNS) believes that any increase in confidence of the Portions 1 through 7 piping integrity attained by pressurizing the piping to 2235 psig would not be commensurate with the increase in radiation exposure and/or safety hazards that station personnel would be subjected to, as well as the risk imposed on both the unit's safe operation and the structural integrity of the nuclear safety related piping and components.

If a leak were to develop at any of the piping locations discussed in this relief request, the instrumentation available to the operators for detection and monitoring of RCS leakage would provide prompt qualitative information to permit them to take immediate corrective action. If any through wall leakage should develop in any of the locations covered in this relief request, the following systems are in place with indications and/or alarms in the Control Room for prompt detection and general location of the leakage:

- EMF monitors 38 and 39 - Containment Atmosphere Gaseous and Particulate Radioactivity Monitoring System.

- EMF monitor 40 - Containment Atmosphere Iodine Monitor.

- Containment Floor and Equipment Sump Level and Flow Monitoring Subsystem where unidentified accumulated water on the containment floor would be monitored and evaluated as sump level changes;
- Containment Ventilation Unit Condensate Drain Tank Level Monitoring Subsystem which collects and measures (as unidentified leakage) the moisture removed from the containment atmosphere.

Plant Technical Specifications require that a reactor coolant system water inventory balance be performed on a regular basis. This computer based mass balance is performed at a minimum every 72 hr. as required by the Tech. Specs. or whenever the operators suspect any leakage. Plant Technical Specification 3.4.13 requires that the unidentified leak rate be returned within the 1 gpm [gallon per minute] limit in 4 hours, or the plant be put in Hot Standby (Mode 3) within 6 hours and in Cold Shutdown within 36 hours. Through wall leakage as discussed in this request for relief would show up as unidentified leakage and be subject to the 1 gpm limit.

There are other leakage detection methods available to the operator which include:

- Volume Control Tank (VCT) level changes.
- VCT make-up frequencies[.]
- Cold Leg Accumulator level changes[.]

At the beginning of a refueling outage, plant personnel enter the Reactor Building in Mode 3 with the RCS still at high energy and inspect for any anomalies that would require re-work, repair or further examination. This includes any evidence [sic] of leakage or of boron residues that would indicate RCS pressure boundary leakage. Through wall leakage in the RCS pressure boundary would be evident by the existence of boron or boron residues on the piping components and/or insulation.

Reduced Pressure Testing of piping for visible “through wall” leakage, reveals that through wall leakage that would occur at higher pressures such as RCS pressure would also reveal itself at lower pressures when a significant "reduced pressure ratio" exists for the reduced pressure used. It may take longer for some leaks to propagate through the piping wall at lower pressures, but generally, during reduced pressure testing, the resulting leak <u>rates</u> would be reduced, but the leakage would still be visible to VT-2 examination. (See Alternative Testing Discussion.)

Inspections that reveal no leakage at lower testing pressures of a significant ratio to 2235 psig (where a leak rates percentage of $30% of the leakage rate produced by 2235 psig pressures would be present for visual detection during VT-2 examination) therefore give high confidence that no leakage would be present at 2235 psig.

The pressure values used in the reduced pressure testing performed as alternative pressure tests for the piping covered in this request for relief, range from approximately 250 psig to $800 psig. Pressures that range from approximately 250 psig to $800 psig are sufficient to provide for the detection of through wall leakage in the tested piping and components during the performance of the alternative test. Therefore, the pressure tests and VT-2 examinations at the lower pressures indicated, provide an acceptable level of assurance of the quality, safety and structural integrity of the piping.

Each alternate test indicated in this RFR [request for relief] will be performed using quantified, reduced pressures for hold times and VT-2 examinations to detect the existence of any through wall leakage on the tested piping. The tested piping boundaries included all the piping segments listed in Section I[4] as part of this Request for Relief.

Each portion of piping listed in this request for relief will be VT-2 examined during Startup process with the RCS at full temperature and pressure and in its normal alignment (after a 4 hr hold time) during the 10 year Class 1 Leakage Test performed per [ASME] Code Case N-498-1 during startup at the end of outage.

Also, these segments of piping are within the scope of the Inservice Inspection Program and thus undergo both volumetric and surface examinations as required on a periodic basis.

Additional Information provided by the licensee’s letter dated May 16, 2005:

Portion 6:

A VT-2 qualified QC [Quality Control] Inspector will examine the piping after a four hour hold time with the Reactor Coolant System (NC) at RCS pressure and temperature (2235 psig @ 557EF) with all affected double isolation valves and test/drain valves in their normal operating position (closed). These portions of piping could see a range of pressures dependent on valve leakage during the pressure test. With leakage through valves NC4, NC13, NC19 and NC94 for Portion 6, the high end of the range is RCS pressure. For the unlikely case of no leakage through these valves, the pressure in these portions of piping could be near atmospheric.

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4. See Section 3.1 of this safety evaluation for listing of piping segments for the licensee’s request for relief.

This alternative provides reasonable assurance of structural integrity because these lines are water filled and it is expected that any leak on these portions of piping would be identified by active leakage or boric acid deposits observed during the pressure test. Any leakage during the previous operating cycle would be indicated by boron deposits on the outside surface of the uninsulated piping regardless of valve leakage during the pressure test inspection. Furthermore, the pipe and fitting material is stainless steel as indicated in the response to question 7 in the January 27, 2005 letter. The piping and valve connections are socket welded and have been qualified for all design conditions including pressure, thermal, and seismic loadings. There is a significant margin in the required wall thickness for this 2” schedule 160 piping based on pressure loadings. (The required wall thickness for 2” schedule 160, SA376, TP304 pipe at a pressure of 2235 psig and a temperature of 650EF is 0.155”; the provided wall thickness is 0.343”.) There are no common degradation mechanisms associated with Grade 304 stainless steel in the pressurized water reactor primary water environment as indicated by the response to question 7. The segment lengths of piping within the scope of this request are small (an average of approximately 3 feet of piping for each loop) and the associated number of socket welded joints are also small (an average of approximately 8 welds per loop). Past surface examinations of a subset of these welds have not identified any reportable indications. Based on these reasons, this alternative provides reasonable assurance of the structural integrity of this piping.

<u>Portion 7</u>:

A VT-2 qualified QC Inspector will examine the piping after a four hour hold time with the NC system at RCS pressure and temperature (2235 psig @ 557EF) with all affected double isolation valves and test/drain valves in their normal operating position (closed). These portions of piping could see a range of pressures dependent on valve leakage during the pressure test. With leakage through valves NC298, NC311, NC250A and NC252B for Portion 7, the high end of the range is RCS pressure. For the unlikely case of no leakage through these valves, the pressure in these portions of piping could be near atmospheric.

This alternative provides reasonable assurance of structural integrity because these uninsulated line lengths are small, the number of welded joints is few, the margin in pipe wall thickness is large for the operating pressure, and the piping and fitting materials have been very reliable for applications under pressurized water reactor primary system conditions.

During operation, the piping segments associated with valves NC298, NC311, NC250A, and NC252B are air filled. However, any leakage through these valves and subsequent leakage of the pressure boundary would quickly purge the relatively small air volumes associated with these segments. A four hour hold time at operating temperature and pressure prior to the pressure test further ensures that any leakage would be identified.

It is expected that any leak on these segments of piping would be identified during the pressure test in the form of boric acid deposits. Even with extremely low valve leakage, these segments are expected to pressurize over the operational cycle. If a pressure boundary leak occurs, any air would be subsequently purged from the volume, followed by the leak out of primary system water and the accumulation of boron residue as the water evaporates in the ambient containment environment. Thus, any leakage during the previous operating cycle would be indicated by boron deposits on the outside surface of the uninsulated piping and identified during plant walkdowns or the alternative pressure test.

Table 1

Segment (1)	Initial Operational Fluid	Pipe Size	t_n (provided pipe wall thickness, in)	t_{req} for 2235 psig @ 650EF, in	Piping Segment Length	Number of Welded Conn	Weld Type
NC298	air	3" sch 160	0.437	0.229	6"	2	butt
NC311	air	3/4" sch 160	0.218	0.069	6"	2	socket
NC250A & NC252B	air	1" sch 160	0.250	0.086	4' - 6"	10 total	socket

(1) only the inboard reactor coolant loop valve has been listed here to identify the Portion 7 segment

The Portion 7 piping and valve connections are welded joints as indicated in Table 1 above and have been qualified for all design conditions including pressure, thermal, and seismic loadings. For pressure loads, there is a significant margin in the required wall thickness for these piping segments as indicated above. There are no common degradation mechanisms associated with Grade 304 stainless steel in the pressurized water reactor primary water environment as indicated by the response to question 7 in the January 27, 2005 letter. The segment lengths of piping within the scope of this request are small and the associated number of welded joints is also small. Past surface and volumetric examinations of a subset of these welds have not identified any reportable indications. Based on these reasons, this alternative provides reasonable assurance of the structural integrity of this piping.

4.0 NRC STAFF EVALUATION

The NRC staff has evaluated hardship to the licensee in performing the ASME Code-required system leakage tests of those components listed in the submittal, at a test pressure corresponding to the pressure associated with 100 percent of rated reactor power. The components in each case are connected to the RCS but are normally isolated from direct RCS pressure during normal operation. They are isolated from the reactor coolant loop by their location, either upstream of a check valve, between two check valves, or between two closed valves that must remain closed during the unit's operation (or startup) in Modes 3, 2, or 1. The licensee has separated the various systems and components in to seven different portions based on test pressure and function of the portion piping of the system.

For all the portions of piping, there would personal safety hazards ranging from immediate physical exposure to temporary connections whose medium is pressurized to 2235 psig and temperatures as high as 557 EF. Operators will have to be stationed at opened manual vent/drain valves serving as RCS single isolation pressure and temperature barriers in order to maintain the RCS boundary redundant valve protection requirement of 10 CFR 50.55a(c)(ii) during the test. In addition, the station operators setting up system leakage testing activities and positioned near subject valves during the testing would be subject to radiation exposure. The radiation exposure would range from 75 - 500 mrem/hr on contact in the areas where the subject portions of piping are located.

The material for the subject portions is austenitic stainless steel. The licensee noted that these stainless steel piping segments have performed without evidence of general corrosive attack in pressurized water reactor service and there are no known concerns with flow accelerated corrosion, erosion, or boric acid corrosion. At Catawba, Units 1 and 2, the licensee has implemented restrictive controls on the RCS chemistry, including control of oxygen and chlorides, during startup and operation along with periodic flushes during refueling outages. In addition, the licensee noted that Catawba has no history of corrosion degradation of the subject portions of these lines. Furthermore, the licensee's ASME Code-required volumetric and/or surface examinations of the welds within the portions of the subject piping to date have not indicated any reportable indications.

Portion 1 is in the chemical volume and control system and is made up of 97 feet of 2 inch, Class 1 piping and components upstream of the auxiliary spray inboard check valve NV-38 up to and including outboard RCS isolation valves NV-37A (globe valve) and NV-861 (check valve). If the licensee pressurizes the chemical volume and control system piping to 2235 psig upstream of the pressurizer isolation check valve NV-38 during Catawba, Unit 1 or Unit 2 startup with the RCS at normal operating pressure and temperature, it would pose a significant hardship because of the risk of an inadvertent pressurizer auxiliary spray initiation. This would cause an upset condition design transient.

As an alternative to the ASME Code requirements, the licensee proposes that, during shutdown, a system leakage test will be performed on the subject piping at a lower pressure, between 250-350 psig, in lieu of the RCS operating pressure of 2235 psig. After a 4 hour hold time the licensee will perform a VT-2 visual examination. In addition, the subject segments of this piping receive a surface examination in accordance with the ASME Code. Therefore, the NRC staff determined that to require the licensee to use the operating pressure as the system leakage test pressure is an unusual hardship without a compensating increase quality and safety. The licensee's proposed alternative to use a lesser test pressure, with the addition of the ASME Code-required nondestructive examination (NDE) provides reasonable assurance of leak tightness and structural integrity of the subject Portion 1 piping segments.

Portion 2 is in the residual heat removal system and is made up of 302 feet of 12 inch and 3/4 inch Class 1 piping and components on the suction line between the RCS double isolation gate valves 1ND-1B and 1ND-2A (A Train) and valves ND-36B and ND-37A (B Train) up to and including their gates. If the licensee were required to perform the system leakage test at the operating pressure of 2235 psig, opening valve ND-1B or ND-36B during RCS pressurization to pressurize the Portion 2 piping would cause an unusual hardship without a compensating increase in quality and safety. Testing Portion 2 piping at operating pressure would violate the requirement of the double isolation valve barrier of the RCS boundary from the ND system.

Performing the system leakage test at operating pressure could also cause the licensee to lose the ability to mitigate a loss-of-coolant if a break were to occur in the 12 inch piping between valves ND-1B and ND-2A, ND-36B, and ND-37A. However, valve ND-1B or ND-36B may not be able to close due to the flow from the RCS through a 12 inch line break. This condition could also expose the residual heat removal system components to an unnecessary risk of damage with only a single valve isolation as the barrier between RCS pressure and non-code piping.

As an alternative to the operating pressure, the licensee proposes to use 325 psig which is the practical operating pressure of the residual heat removal system suction that is nominally maintained when the RCS is pressurized. The licensee also had to consider the restrictions of the residual heat removal system suction piping at operating pressure including: the open permissive pressure for ND-1B and 2A and ND-36B and ND-37A is < 425 psig; relief valves ND-3 and ND-38 have a nominal lift set point of 450 psig; and residual heat removal system operating procedures limit RCS pressure to less than 385 psig. In addition to the system leakage test, the Portion 2 segments of piping receive an ASME Code-required volumetric and surface examination. Therefore, the NRC staff determined that the alternative test pressure of 325 psig with the proposed hold times, VT-2 examination for leakage and the ASME Code-required NDE examinations provide reasonable assurance of leak tightness and structural integrity of the subject Portion 2 piping segments.

Portion 3 is in the safety injection system and is made up of 32 feet of 1½ inch Class 1 piping and components on each of the 4 RCS loops and between the double isolation check valves, including the second isolation check valves, for the RCS cold leg boron injection system. The Portion 3 piping has no connections with which to pressurize the piping segment with a local pump. In order to pressurize Portion 3, one of the charging pumps must be aligned to inject cold borated water into the RCS resulting in a potential cold leg thermal design transient and, thus, potentially affecting the plant's design operating life. Therefore, the NRC staff determined that to require the licensee to perform the system leakage test on Portion 3 piping at operating pressure would cause a significant hardship without a compensating increase in quality and safety.

As an alternative to the operating pressure, the licensee proposes to pressurize the Portion 3 piping to $800 psig. The NRC staff determined that the licensee’s proposed use of $800 psig as the system leakage test pressure during testing along with its proposed holding times provides reasonable assurance of leak tightness and structural integrity of the subject Portion 3 piping. Furthermore, the Portion 3 segments receive a surface examination in accordance with the ASME Code requirements which provides further assurance of leak tightness and structural integrity of these segments of piping.

Portion 4 is in the cold leg safety injection system piping and components upstream of the 10 inch RCS isolation check valves on each of the 4 RCS loops. The Portion 4 piping segment is made up of 10 inch, 6 inch, 2 inch, 1 inch, and 3/4 inch ASME Class 1 piping with a total of 765 feet of piping. Portion 5 is in the hot leg safety injection system piping and components up stream of the hot leg injection isolation check valves for hot legs A, B, C, and D, respectively; back to the respective discharge isolation check valve and associated 3/4 inch line with flow restrictor for each train of piping. Portion 5 is made up of 8 inch, 6 inch, 4 inch, 2 inch, and 3/4 inch ASME Class 1 piping and components with a total of 383 feet of piping.

If the ASME Code requirements were imposed on the licensee, it would have to introduce RCS pressure between the pressure isolation check valves (PIVs) that would likely cause the inboard PIV to unseat, placing the station in a Technical Specification action condition. The PIVs serve as the RCS pressure boundary and have allowable leakage rate limits that prevent overpressurization to the low pressure portions of the connecting safety injection system piping as well as the loss of integrity of a fission product barrier. Furthermore, if the licensee used a hydro pump to pressurize Portion 4 or Portion 5 piping, all 4 of the inboard safety injection system check valves interfacing the RCS would have to be temporarily gagged closed to provide a pressurization boundary. Gagging the subject check valves to hold 2235 psig would pose a substantial risk of damage to the components from the loads that would be transferred to the valve bodies. Therefore, the NRC staff determined that to require the licensee to perform the ASME Code-required test on Portions 4 or 5 would be an usual hardship without a compensating increase in quality and safety.

As an alternative to the operating pressure, the licensee proposes to pressurize the Portion 4 piping segment to 585 psig and to pressurize the Portion 5 piping segment to 327 psig. The NRC staff determined that the licensee’s proposed use of 585 psig and 327 psig as the system leakage test pressure for the respective cold and hot leg segments of the safety injection system piping during testing along with its proposed holding times provides reasonable assurance of leak tightness and structural integrity of Portions 4 and 5. Furthermore, Portions 4 and 5 receive a volumetric and surface examination in accordance with the ASME Code, that further provides assurance of leak tightness and structural integrity of these segments of piping.

Portion 6 is made up of 2 inch RCS Class 1 piping and components between and including the double isolation globe valves isolating the RCS loop from the liquid waste recycle system piping routed to the reactor coolant drain tank pump. There is one segment on each of the 4 loops of the units. Portion 7 (20 feet long) is made up of 3/4 inch, 1 inch, and 3 inch RCS Class 1 piping between and including the double isolation valve pairs on the reactor vessel head vent line.

If the ASME Code requirements were imposed on the licensee, it would have to test both Portions 6 and 7 at RCS pressure by opening the inside RCS loop isolation valves at the onset of RCS pressurization. However, these valves are the first of a series of two valves maintaining double isolation of the RCS pressure boundary either from other piping or from the containment atmosphere. Opening these valves to pressure test this piping at RCS pressure would eliminate the double valve protection, creating a single valve barrier between the RCS pressure boundary and non-code piping. The piping on the discharge side of these single valve barriers is non-code piping and not designed to serve as part of the RCS double isolation pressure boundary.

In addition, the station personnel would have to be at or near the opened valve(s) in the lower containment area with RCS at normal operating pressure and temperature, which would place the station personnel in hazardous conditions. For Portion 7 there are no connection points for a test connection between the reactor head vent pipe double isolation valves to pressurize the piping by hydro pump or temporary jumper. Therefore, the NRC staff determined that for Portions 6 and 7, imposing the ASME Code requirements would be an unusual hardship without a compensating increase in quality and safety.

For Portion 6, the licensee proposed, as an alternative test pressure, that it will perform a VT-2 examination for evidence of leakage after the subject piping has undergone a 4 hour hold time with the RCS at operating pressure and temperature (2235 psig @ 557 EF) with all affected double isolation valves and test/drain valves in the closed position (normal operating position). This portion of piping could see a range of pressures dependent on valve leakage during the pressure test. With leakage through valves NC4, NC13, NC19 and NC94 for Portion 6, the high end of the range is RCS pressure. For the unlikely case of no leakage through these valves, the pressure in these portions of piping could be near atmospheric. Portion 6 is normally filled with water at atmosphere pressure and it is expected that any leak on this portion of piping would be identified by active leakage or boric acid deposits observed during the pressure test. Furthermore, any leakage during the previous operating cycle would be indicated by boron deposits on the outside surface of the uninsulated piping regardless of valve leakage during the pressure test inspection.

The Portion 6 piping and fitting material is SA376, TP304 stainless steel, and the piping and valve connections are socket welded and have been qualified for all design conditions including pressure, thermal, and seismic loadings. The piping is schedule 160 piping based on pressure loadings of 2235 psig and a temperature of 650 EF. There are no common degradation mechanisms associated with Grade 304 stainless steel in the pressurized water reactor primary water environment. The segment lengths of the subject piping are approximately 3 feet of piping for each loop and the associated number of socket welded joints are approximately 8 welds per loop. The licensee has performed ASME Code-required surface examinations of a subset of the subject welds and did not identify any reportable indications. Therefore, the NRC staff determined that, based on above, the licensee’s proposed alternative provides reasonable assurance of the leak tightness and structural integrity of Portion 6 piping.

For Portion 7, the licensee proposed to perform a VT-2 examination of the reactor vessel head vent line piping after a four hour hold time with the RCS at operating pressure and temperature with all affected double isolation valves and test/drain valves in the closed position (normal operating position). This portion of piping could see a range of pressures dependent on valve leakage during the pressure test. If there is no leakage through these valves, the pressure in these portions of piping would be near atmospheric. Although Portion 7 does not normally contain borated water, if for some reason the valves did leak and was not detected in the Portion 7 piping, the instrumentation available to the licensee for detection and monitoring of RCS leakage would provide prompt information to allow the licensee to take corrective action.

The licensee noted that during operation, the subject piping segments associated with valves NC298, NC311, NC250A, and NC252B are air filled. The licensee also noted that if any RCS leakage through these valves and subsequent leakage of the pressure boundary occurred, it would quickly purge the relatively small air volumes associated with the subject piping segments. If any leakage occurred during the previous operating cycle, boron deposits would be found on the outside surface of the piping and identified during plant walkdowns or during the alternative pressure test.

The Portion 7 piping and fitting material is SA376, TP304 stainless steel, and the piping and valve connections are socket or butt welded and have been qualified for all design conditions including pressure, thermal, and seismic loadings. The piping is schedule 160 and the wall thickness ranges from 0.250 inches to 0.437 inches based on pressure loadings of 2235 psig at a temperature of 650 EF. Based on its operating experience, the licensee found that there are no common degradation mechanisms associated with Grade 304 stainless steel in the pressurized water reactor primary water environment. The lengths of Portion 7 piping range from 6 inches to 4 feet 6 inches and the associated number of welded joints range from 2 to 10 for each segment of piping. The ASME Code required surface and volumetric examinations were performed on the Portion 7 piping and no reportable indications were found. Therefore, the NRC staff determined that based on above, the licensee’s proposed alternative provides reasonable assurance of the leak tightness and structural integrity of Portion 7 piping.

In summary, the NRC staff determined that use of a higher testing pressure for components that would not normally be subject to RCS pressure during 100 percent rated reactor power operation would not result in an increase in assurance of structural integrity commensurate with the potential challenges that would be placed on the facility and plant personnel. In the unlikely event of not detecting a leak in the subject piping segments during the refueling outage, the instrumentation available to the operators for detection and monitoring of RCS leakage would provide prompt qualitative information to permit them to take immediate corrective action during operation. Therefore, the NRC staff has determined that compliance with the ASME Code requirements used in conjunction with invoking ASME Code Case N-498-1 in regard to the required test pressure during system leakage test for the piping segments and components identified in the licensee's relief request would result in unusual hardship without a compensating increase in the level of quality and safety.

Furthermore, the proposed test pressures along with the proposed hold times provide reasonable assurance of leak tightness and structural integrity of the subject piping segments referenced in this relief. In addition, the ASME Code-required NDE performed and routine line walk downs provide additional assurance of leak tightness and structural integrity of the subject piping segments.

5.0 CONCLUSIONS

The NRC staff concludes that for components identified in Relief Request 04-CN-004, performance of the system leakage test conducted at a test pressure corresponding to the operating pressure of the component, as stated in the licensee's proposed alternative, in lieu of testing at the RCS pressure associated with 100 percent rated reactor power as required by the ASME Code, is acceptable. The NRC staff has determined that for these portions of the Class 1 boundary, compliance with the requirements of the ASME Code as stated in Paragraph IWB-5221 used in conjunction with invoking ASME Code Case N-498-1 with regard to the required test pressure during the system leakage test would result in hardship or unusual difficulty without a compensating increase in the level of quality and safety.

The NRC staff concludes that the licensee’s proposed alternative test pressures provide reasonable assurance of leak tightness and structural integrity of the subject portions of piping segments. Furthermore, the subject segments of piping receive a volumetric examination, surface examination, or both, in accordance with ASME Code requirements which provide additional assurance of leak tightness and structural integrity of the subject segments of piping. Therefore, pursuant to 10 CFR 50.55a(a)(3)(ii), the licensee's proposed alternative is authorized for Catawba, Units 1 and 2 for the second 10-year inspection interval. All other requirements of the ASME Code, Section III and XI for which relief has not been specifically requested remain applicable, including third party review by the Authorized Nuclear Inservice Inspector.

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