UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

March 30, 2011

Mr. Lawrence J. Weber
Senior Vice President and
Chief Nuclear Officer
Indiana Michigan Power Company
Nuclear Generation Group
One Cook Place
Bridgman, MI 49106

SUBJECT: DONALD C. COOK NUCLEAR PLANT, UNITS 1 AND 2 – EVALUATION OF INSERVICE INSPECTION RELIEF REQUESTS ISIR-4-01, -02, -03, AND -04 (TAC NO. ME4495 AND ME4496)

Dear Mr. Weber:

By letter dated March 12, 2010, as supplemented by letter dated November 12, 2010, Indiana Michigan Power Company (the licensee) submitted, among other things, four inservice inspection (ISI) relief requests, identified as ISIR-4-01, -02, -03, and -04 to the Nuclear Regulatory Commission (NRC) for relief from certain requirements of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code).

For Relief Request ISIR-4-01, the NRC staff concludes that the licensee's proposed risk-informed/safety-based ISI program will provide an acceptable level of quality and safety pursuant to Title 10 of the *Code of Federal Regulations* (10 CFR) 50.55a(a)(3)(i) for the proposed alternative to the piping ISI requirements with regard to (1) the number of locations, (2) the locations of inspections, and (3) the methods of inspection. Therefore, the proposed risk-informed ISI program is authorized for the fourth 10-year ISI interval pursuant to 10 CFR 50.55a(a)(3)(i) on the basis that this alternative will provide an acceptable level of quality and safety.

For Relief Requests ISIR-4-02, -03, and 04, the NRC staff concludes that the licensee provided sufficient technical basis to find that compliance with the current requirements would cause an unnecessary burden on the licensee without a compensating increase in the level of quality and safety. Therefore, the licensee's proposed alternative is authorized pursuant to 10 CFR 50.55a(a)(3)(ii) for the fourth 10-year ISI interval.

Details of the NRC staff's review are set forth in the enclosed Safety Evaluation.

If you have any questions, please contact the Project Manager Mr. Peter Tam at (301) 415-1451.

Sincerely,

Robert J. Pascarelli, Chief
Plant Licensing Branch III-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. 50-315 and 50-316

Enclosure:
Safety Evaluation

cc w/encl: Distribution via ListServ

UNITED STATES
NUCLEAR REGULATORY COMMISSION
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SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

INSERVICE INSPECTION RELIEF REQUESTS IS-IR-4-01, -02, -03, AND -04

INDIANA MICHIGAN POWER COMPANY

DONALD C. COOK NUCLEAR PLANT, UNITS 1 AND 2 (CNP)

DOCKET NO. 50-315 AND 50-316

1.0 INTRODUCTION

By letter dated March 12, 2010 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML100750680), Indiana Michigan Power Company (the licensee) submitted to the Nuclear Regulatory Commission (NRC) Relief Requests ISIR-4-01, -02, -03, and -04, applicable to the CNP units' fourth 10-Year inservice inspection (ISI) intervals. The requests were part of CNP's fourth 10-year interval inservice inspection program plan. By letter dated November 12, 2010 (ADAMS Accession No. ML103270092) the licensee provided supplemental information. These four relief requests (RRs) are evaluated in the following sections.

2.0 RELIEF REQUEST ISIR-4-01

The licensee requested to implement a risk-informed/safety-based inservice inspection (RIS_B) program based, in part, on American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) Case N-716, "Alternative Piping Classification and Examination Requirements, Section XI Division 1," dated April 19, 2006. The provisions of N-716 may be used in lieu of the requirements of IWB-2420, IWB-2430, Table IWB-2500-1 (Examination Categories B-F and B-J), IWC-2420, IWC-2430, and Table IWC-2500-1 (Examination Categories C-F-1 and C-F-2) for inservice inspection of Class 1 or 2 piping and IWB-2200 and IWC-2200 for preservice inspection of Class 1 or 2 piping, or as additional requirements for Class 3 piping or Non-Class piping, for plants issued an initial operating license prior to December 31, 2000. The N-716 requirements are expected to reduce the number of inspections required but also define additional requirements for Class 3 piping or non-Class piping.

N-716 has not been endorsed by the NRC for generic use. The licensee's RR refers to the methodology described in N-716 instead of describing the details of the methodology in the RR. The licensee has, however, modified the methodology described in N-716 while developing its proposed RIS_B program. When the methodology used by the licensee is accurately described in N-716, this safety evaluation (SE) refers to the details found in N-716. When the methodology used by the licensee deviates or expands upon the methodology described in N-716, this SE refers to the licensee's submittals cited above. Therefore, N-716 is incorporated in this SE only as a source for some of the detailed methodology descriptions as needed and the NRC staff is not endorsing the use of Code Case N-716 via this SE.

Enclosure

2.1 Regulatory Evaluation

Pursuant to Title 10 of the *Code of Federal Regulations* (10 CFR) 50.55a(g), ASME Code Class 1, 2, and 3 components (including supports) shall meet the requirements, "except design and access provisions and preservice examination requirements" set forth in the Code to the extent practical within the limitations of design, geometry, and materials of construction of the components. Paragraph 10 CFR 50.55a(g) also states that ISI of the ASME Code, Class 1, 2, and 3 components is to be performed in accordance with Section XI of the ASME Code and applicable addenda, except where specific relief has been granted by the NRC. The objective of the ISI program, as described in Section XI of the ASME Code and applicable addenda, is to identify conditions (i.e., flaw indications) that are precursors to leaks and ruptures in the pressure boundary of these components that may impact plant safety.

The regulations also require, during the first 10-year ISI interval and during subsequent intervals, that the licensee's ISI program complies with the requirements in the latest edition and addenda of Section XI of the ASME Code incorporated by reference into 10 CFR 50.55a(b) 12 months prior to the start of the 120-month interval, subject to the limitations and modifications listed therein. CNP is currently in its fourth 10-year ISI interval which began March 1, 2010.

Pursuant to 10 CFR 50.55a(g), a certain percentage of ASME Code Category B-F, B-J, C-F-1 and C-F-2 pressure retaining piping welds must receive ISI during each 10-year ISI interval. The ASME Code requires 100 percent of all B-F welds and 25 percent of all B-J welds greater than 1-inch nominal pipe size be selected for volumetric or surface examination, or both, on the basis of existing stress analyses. For Categories C-F-1 and C-F-2 piping welds, 7.5 percent of non-exempt welds are selected for volumetric or surface examination, or both. According to 10 CFR 50.55a(a)(3), the NRC may authorize alternatives to the requirements of 10 CFR 50.55a(g), if an applicant demonstrates that the proposed alternatives would provide an acceptable level of quality and safety, or that compliance with the specified requirement would result in hardship or unusual difficulty without a compensating increase in the level of quality and safety. The licensee has proposed to use an RIS_B program for ASME Code Class 1 and Class 2 piping (Examination Categories B-F, B-J, C-F-1 and C-F-2 piping welds), as an alternative to the ASME Code, Section XI requirements. As stated in Section 1.0 of this safety evaluation, the provisions of N-716 are expected to reduce the number of required examinations but may also define additional requirements for Class 3 piping or non-class piping. The application states that this proposed program will be substituted for the current program in accordance with 10 CFR 50.55a(a)(3)(i) by alternatively providing an acceptable level of quality and safety.

The licensee stated that N-716 is founded in large part on the risk-informed inservice inspection (RI-ISI) process as described in Electric Power Research Institute TR-112657 Revision B-A, "*Revised Risk-Informed Inservice Inspection Evaluation Procedure*," (EPRI TR) (ADAMS Accession Number ML013470102), which was previously reviewed and approved by the NRC. The NRC staff has reviewed the development of the proposed RIS_B RI-ISI program using the following documents:

Regulatory Guide (RG) 1.174, "*An Approach for Using Probabilistic Risk Assessment In Risk-Informed Decisions On Plant-Specific Changes to the Licensing Basis*" (ADAMS Accession Number ML023240437),

RG 1.178, "*An Approach For Plant-Specific Risk-Informed Decisionmaking - Inservice Inspection of Piping*" (ADAMS Accession Number ML032510128), and

RG 1.200, Revision 1, *"An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities"* (ADAMS Accession Number ML070240001).

RG 1.174 provides guidance on the use of probabilistic risk analysis (PRA) findings and risk insights in support of licensee requests for changes to a plant's licensing basis. RG 1.178 describes a RI-ISI program as one that incorporates risk insights that can focus inspections on more important locations while at the same time maintaining or improving public health and safety. RG 1.200 describes one acceptable approach for determining whether the quality of the PRA, in total or the parts that are used to support an application, is sufficient to provide confidence in the results, such that the PRA can be used in regulatory decision-making

2.2 Technical Evaluation

N-716 is founded, in large part, on the RI-ISI process as described in the EPRI TR, which was previously reviewed and approved by the NRC. In general, the licensee simplified the EPRI TR method because it does not evaluate system parts that have been generically identified as high-safety-significant (HSS), and uses plant-specific PRA to evaluate in detail only system parts that cannot be screened out as low-safety-significant (LSS).

An acceptable RI-ISI program replaces the number and locations of nondestructive examination (NDE) inspections based on ASME Code, Section XI requirements with the number and locations of these inspections based on the RI-ISI guidelines. The proposed RIS_B program permits alternatives to the requirements of IWB-2420, IWB3-2430, IWB-2500 (Examination Categories B-F and B-J), IWC-2420, IWC-2430, and IWC-2500 (Examination Categories C-F-1 and C-F-2), or as additional requirements for Subsection IWD, and may be used for ISI and preservice inspection of Class 1, 2, 3, or Non-Class piping. All piping components, regardless of risk classification, will continue to receive ASME Code-required pressure and leak testing, as part of the current ASME Code, Section XI program.

The EPRI TR RI-ISI process includes the following steps which, when successfully applied, satisfy the guidance provided in RGs 1.174 and 1.178.

- Scope definition
- Consequence evaluation
- Degradation mechanism evaluation
- Piping segment definition
- Risk categorization
- Inspection/NDE selection
- Risk impact assessment
- Implementation monitoring and feedback

These processes result in a program consistent with the concept that, by focusing inspections on the most safety-significant welds, the number of inspections can be reduced while at the same time maintaining protection of public health and safety. In general, the methodology in N-716 replaces a detailed evaluation of the safety significance of each pipe segment with a generic population of high safety-significant segments, followed by a screening flooding analysis to identify any plant-specific high safety-significant segments. The screening flooding analysis is performed in accordance with the flooding PRA approach that is consistent with Section 4.5.7 of

ASME RA-Sb-2005, Standard for Probabilistic Risk Assessment for Nuclear Power Plant Applications, Addendum B to ASME RA-S-2002 (ASME, New York, New York, December 30, 2005), as endorsed in RG 1.200. As described below, the acceptability of the licensee's proposed RIS_B program is evaluated by comparing the processes it has applied to develop its program with the steps from the EPRI-TR process.

2.2.1 Scope Definition

The scope of evaluation to support RIS_B program development and of the proposed changes includes ASME Code Class 1, 2, 3 and Non-Class piping welds. Standard Review Plan (SRP) 3.9.8 and N-716 address scope issues. The primary acceptance guideline in the SRP is that the selected scope needs to support the demonstration that any proposed increase in core damage frequency (CDF) and risk are small. The scope of CNP's evaluation included all piping where ASME inspections could be discontinued providing assurance that the change in risk estimate would, as a minimum, capture the risk increase associated with implementing the RIS_B program in lieu of the ASME program. RG 1.178 identifies different groupings of plant piping that should be included in a RI-ISI program, and also clarifies that a "full-scope" risk-informed evaluation is acceptable. The scope of the RIS_B program as defined in N-716 is consistent with the definition of full-scope in RG 1.178. Therefore, the NRC staff concludes that the "full-scope" extent of the piping included in the RIS_B program changes satisfies the SRP and RG guidelines and is acceptable.

2.2.2 Consequence Evaluation

The methodology described in RG 1.178 and the EPRI TR divide all piping within the scope of the proposed EPRI RI-ISI program into piping segments. The consequence of each segment failure must be estimated as a conditional core damage probability (CCDP) and conditional large early release probability (CLERP) or by using a set of tables in the EPRI TR that yield equivalent results. The consequences are used to determine the safety significance of the segments.

In contrast to the EPRI TR methodology, N-716 does not require that the consequence of each segment failure be estimated to determine the safety-significance of piping segments. Instead, N-716 identifies portions of systems that should be generically classified as HSS at all plants. A consequence analysis is not required for system parts generically classified as HSS because there is no higher safety significance category to which the system part can be assigned and degradation mechanisms, not consequence, are used to select inspection locations in the HSS weld population. The licensee's PRA is subsequently used to search for any additional, plant-specific HSS segments that are not included in the generic HSS population.

Sections 2(a)(1) through 2(a)(4) in N-716 provide guidance that identifies the portions of systems that should be generically classified as HSS based on a review of almost 50 RI-ISI programs. These previous RI-ISI programs were all developed by considering both direct and indirect effects of piping pressure boundary failures and the different failure modes of piping. This is consistent with the guidelines for evaluating pipe failures with PRA described in RG 1.178, the EPRI TR, and SRP 3.9.8, and, therefore, the generic results are derived from acceptable analyses. Section 2(a)(5) in N-716 provides guidance that defines additional, plant-specific HSS segments that should be identified using a plant-specific PRA of pressure boundary failures.

Each of the licensee's consequence evaluations (the generic and the plant-specific flooding analysis) considers both direct and indirect effects of piping pressure boundary failures and the different piping failure modes to systematically use risk insights and PRA results to characterize the consequences of piping failure. This is consistent with the guidelines for evaluating pipe failures with PRA described in RG 1.178 and the EPRI TR and is, therefore, acceptable.

2.2.3 Degradation Mechanism Evaluation

Section 3.4 of the EPRI TR, including its subsections, addresses the identification and evaluation of degradation mechanisms of interest to a RI-ISI program. This section of the EPRI TR notes that there is no correlation between design stresses and piping failures. It further notes that most piping failures are the result of active degradation mechanisms in concert with loading conditions. This section, therefore, places significant emphasis on identifying all applicable degradation mechanisms for all piping segments and appropriately addressing their significance. This section of the EPRI TR fundamentally provides a three step process to identify and evaluate degradation mechanisms:

(a) Based on industry experience, identify all possible degradation mechanisms

(b) Based on plant operating experience, assign degradation mechanisms to piping segments

(c) Based on the degradation mechanisms present assign pipe rupture potential and expected leak conditions to each pipe segment.

This section of the EPRI TR identifies, and contains a description of the conditions required for all applicable degradation mechanisms. The section also characterizes pipe rupture potential as high, medium, or low and the expected leak conditions as large, small, or none. Although not specifically addressed in this section, these classifications are used to assign pipe failure probabilities which are used in determining the pipe failure frequency. This section of the EPRI TR admonishes the user to pay particular attention to the subject of water hammer during the plant operating experience review. Two reasons are cited: first, the occurrence of water hammer is highly plant-specific; and second, the presence of water hammer may necessitate changing the rupture potential category of a given pipe segment from medium to high.

The approaches employed by the EPRI TR, the code case, and the RR with respect to the evaluation of degradation mechanisms are generally similar. Based on the general similarity, the NRC staff accepts the licensee's conceptual approach to this topic. Despite the general similarity between these approaches, there are some significant differences. These are described below.

The EPRI TR and Code Case differ in the number of pipe segments which are evaluated. The EPRI TR requires the evaluation of each pipe segment to determine all applicable degradation mechanisms. This is then used to determine the safety significance of the segment. Alternatively, the Code Case identifies a generic population of piping segments to be assigned to the HSS category without evaluation, followed by a search for plant-specific HSS welds. The Code Case approach is at least as conservative as the EPRI TR approach because it identifies as HSS each piping segment which would have been so identified by the EPRI TR and because it may identify additional piping segments as being of HSS. Based on this conservatism, the NRC finds the use of this aspect of the Code Case acceptable.

In lieu of conducting a degradation mechanism evaluation for all the LSS piping, the licensee conservatively assigned all locations to the medium-failure potential for the purpose of assigning a failure frequency to be used to calculate the change in risk. This results in an equal or greater estimated increase in risk from discontinued inspections because the failure frequencies would always be equal to or less than those used in the licensee's analysis if the susceptibility of all LSS welds to all degradation mechanism was determined. The NRC finds this approach acceptable because the assumed degradation mechanism will always result in the assignment of a failure probability at least as high as the complete analysis required by the EPRI TR methodology.

The EPRI TR and the Code Case both consider a long and identical list of degradation mechanisms. Both of these lists include primary water stress corrosion cracking (PWSCC). In its November 12, 2010, letter the licensee stated that PWSCC of dissimilar metal welds is addressed through a separate augmented inspection program designed to specifically address Alloy 600 welds which are susceptible to PWSCC. The basis for this program is contained in MRP-139, "Materials Reliability Program: Primary System Piping Butt Weld Inspection and Evaluation Guideline," Revision 1 (December 2008, Electric Power Research Institute, Palo Alto, California). The NRC staff finds that the inclusion of these welds in a plant augmented inspection program designed to meet the requirements of MRP-139 acceptable because these welds will be adequately inspected under the augmented program.

The licensee's RR differs from the EPRI TR in the manner in which thermal stratification, cycling, and striping is addressed. The method contained in the EPRI TR does not allow for the consideration of the severity of fatigue. The method proposed by the licensee does. This method has been previously reviewed and accepted by the staff (ADAMS Accession Number ML093220090) and will not be considered further here.

The licensee's RR and the EPRI TR differ on the number of pipe segments evaluated for flow accelerated corrosion (FAC) and water hammer. The EPRI TR states that all pipe segments are to be evaluated for FAC and water hammer as the presence of these degradation mechanisms may affect the failure potential for the piping segment. The licensee stated that it evaluated all piping segments not specified as HSS by the Code Case to determine whether FAC or water hammer was present. The licensee stated that neither FAC nor water hammer was present in the pipe segments considered. The NRC staff finds this approach acceptable as it is consistent with the EPRI TR for those segments considered and it is at least as conservative as the EPRI TR for those segments not fully evaluated as these segments were assumed to be of high safety significance.

2.2.4 Piping Segment Definition

Previous guidance on risk-informed inservice inspection including RG 1.178 and the EPRI-TR centered on defining and using piping segments. RG 1.178 states, for example, that the analysis and definition of a piping segment must be consistent and technically sound.

The primary purpose of segments is to group welds so that consequence analyses can be done for the smaller number of segments instead of for each weld. Sections 2(a)(1) to 2(a)(4) in N-716 identify system parts (segments and groups of segments) that are generically assigned HSS without requiring a plant specific consequence determination and any subdivision of these system parts is unnecessary. Section 2(a)(5) in N-716 uses a PRA to identify plant specific piping that might be assigned HSS. A flooding PRA consistent with ASME RA-Sb-2005 searches for plant specific HSS piping by first identifying zones that may be sensitive to flooding, and then evaluating the failure potential of piping in these zones. Lengths of piping whose failure impacts the same plant equipment within each zone are equivalent to piping segments. Therefore piping segments are either not needed to reduce the number of consequence analyses required (for the generic HSS piping) or, when needed during the plant specific analysis, the length of pipe included in the analysis is consistent with the definition of a segment in RG 1.178.

An additional purpose of piping segments in the EPRI-TR is as an accounting/tracking tool. In the EPRI methodology, all parts of all systems within the selected scope of the RI-ISI program are placed in segments and the safety significance of each segment is developed. For each safety significant classification, a fixed percentage of welds within all the segments of that class are selected. Additional selection guidelines ensure that this fixed percentage of inspections is distributed throughout the segments to ensure that all damage mechanisms are targeted and all piping systems continue to be inspected. N-716 generically defines a large population of welds as HSS. An additional population of welds may be added based on the risk-informed search for plant specific HSS segments. When complete, the N-716 process yields a well-defined population of HSS welds accomplishing the same objective as accounting for each weld throughout the analysis by using segments. The Code Case provides additional guidelines to ensure that this fixed percentage is appropriately distributed throughout the population of welds subject to inspection, all damage mechanisms are targeted, and all piping systems continue to be inspected.

The NRC staff concludes that the segment identification in RG 1.178 as used as an accounting tool is not needed within the generic population of HSS welds. A flooding PRA consistent with ASME RA-Sb-2005 utilizes lengths of piping consistent with the segment definition in RG 1.178 whenever a consequence evaluation is needed. Therefore, the proposed method accomplishes the same objective as the approved methods without requiring that segments be identified and defined for all piping within the scope of the RIS_B program.

2.2.5 Risk Categorization

The licensee's RI-ISI program for the third interval was previously approved (letter, T. L. Tate to M. K. Nazar, September 28, 2007; ADAMS Accession No. ML072620553) and implemented less than two years before submittal of the current RR. The licensee states that no changes were made to the evaluation methodology or conclusions as part of the interval update. The licensee stated that rankings, prorations, and distributions were reviewed and confirmed to meet the requirements of the N-716 program and no major changes were required that would impact the determination of the program's acceptability.

Sections 2(a)(1) through 2(a)(4) in N-716 identify the portions of systems that should be generically classified as HSS, and Section 2(a)(5) requires a search for plant-specific HSS segments. Application of the guideline in Section 2(a)(5) in N-716 identifies plant-specific piping segments that are not assigned to the generic HSS category but that are risk-significant at a particular plant. N-716 requires that any segment with a total estimated CDF greater than 1E-6/year be assigned the HSS category. The licensee augmented this N-716 metric on CDF with the requirement to also assign the HSS category to any segment with a total estimated LERF greater than 1E-7/year. The licensee stated in the previous submittal that these guideline values are suitably small and consistent with the decision guidelines for acceptable changes in CDF and large early release frequency (LERF) found in the EPRI TR. The licensee reviewed the results of its flooding analysis and did not identify any segments that had a CDF greater than 1E-6/year or a LERF greater than 1E-7/year.

Ancillary metrics were added as a defense-in-depth measure to provide a method of ensuring that any plant-specific locations that are important to safety are identified. All piping that has inspections added or removed per N-716 is required to be included in the change in risk assessment and an acceptable change in risk estimate is used to demonstrate compliance with RG 1.174 acceptance guidelines. The ancillary metrics and guidelines on CDF and LERF are only used to add HSS segments and not, for example, to remove system parts generically assigned to the HSS in Sections 2(a)(1) through 2(a)(4).

The NRC staff concurs that a plant-specific analysis to identify plant-specific locations that are important to safety is a necessary element of RI-ISI program development. The results of the plant-specific risk categorization analysis provide confidence that the goal of inspecting the more risk-significant locations is met while permitting the use of generic HSS system parts to simplify and standardize the evaluation. Satisfying the guidelines in Section 2(a)(5) requires confidence that the flooding PRA is capable of successfully identifying all, or most, of the significant flooding contributors to risk that are not included in the generic results. RG 1.200 states that meeting the attributes of an NRC-endorsed industry PRA standard (ASME RA-Sb-2005 at the time of the application) may be used to demonstrate that a PRA is adequate to support a risk-informed application. RG 1.200 further states that an acceptable approach that can be used to ensure technical adequacy is to perform a peer review of the PRA.

In its March 12, 2010, application the licensee states that the CNP Probabilistic Safety Assessment model underwent a focused-scope PRA peer review in 2009 by Westinghouse to determine compliance with Addendum B of the ASME PRA Standard and RG 1.200 Rev 1. The scope of this review included the CNP internal flooding analysis, portions of the human reliability analysis related to revised operator actions for mitigation of Steam Generator Tube Rupture sequences, recent data collection updates, common cause failure methodology and implementation, and systems analysis and accident sequence analysis elements update due to addition of supplemental diesel generator.

In the November 12, 2010, supplement the licensee provided responses that described how the CNP PRA met capability category II of the ASME PRA Standard for pertinent supporting requirements related to the RR. The lciensee concludes that the location of PRA-related equipment relative to the various spray sources, use of conservative estimates of possible spray coverage, and use of conservative systems structures and components (SSC) failure criteria adequately addresses all SSC failures. The licensee states that internal flooding supporting requirements related to screening of flood areas and plant-specific operating experience was characterized as capability category III by the independent focused-scope PRA peer review.

The NRC staff concurs that the CDF and LERF metrics proposed by the licensee are acceptable because they address the risk elements that form the basis for risk-informed applications (i.e., core damage and large early release). The NRC staff accepts the proposed guideline values because these ancillary guidelines are applied in addition to the change in risk acceptance guidelines in RG 1.174, and only add plant-specific HSS segments to the RIS_B program (i.e., they may not be used to reassign any generic HSS segment into the LSS category).

The NRC staff finds that the risk categorization performed by the licensee provides confidence that HSS segments have been identified. Sections 2(a)(1) through 2(a)(4) in N-716 which identify generic HSS portions of systems were applied to CNP piping. The licensee's PRA used to fulfill the guideline in Section 2(a)(5) was performed using a PRA of adequate technical quality based on consistency between the PRA and the applicable characteristics of the NRC-endorsed industry standard ASME RA-Sb-2005.

2.2.6 Inspection/NDE Selection

The licensee's submittals discuss the impact of the proposed RIS_B application on the various augmented inspection programs.

In the RR the licensee states that the CNP augmented inspection program for high energy line breaks (HELB) outside containment is not affected or changed by the RIS_B Program. The staff notes that N-716 contains no provisions for reducing the number of inspections in the inspection program for break exclusion region. However, Code Case N-716 does include a provision to increase the number of HELB inspections if the HELB program is inspecting less than 10 percent of the welds in this region. Changes to the HELB program may be made as authorized by EPRI TR-1006937, "Extension of the EPRI Risk Informed ISI Methodology to Break Exclusion Region Programs," (ADAMS Accession Number ML021790518) or by another process found acceptable by the NRC staff.

N-716 contains no provisions for changing the FAC augmented program developed in response to NRC Generic Letter 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning." The licensee's FAC program is relied upon to manage this damage mechanism but is not otherwise affected or changed by the RIS_B program.

MRP-139 will be used as an augmented inspection program for the inspection and management of PWSCC susceptible dissimilar metal welds and will supplement the RI-ISI program.

The NRC staff finds the licensee's approach to the integration of the proposed RI-ISI program with existing augmented inspection programs acceptable because it is consistent with the EPRI TR.

Section 3.6 of the EPRI TR addresses the selection of pipe segments for inspection. This section presents the current code requirements. It also establishes requirements for the RI-ISI program related to:

Class 1 category BJ welds
Class 1, 2, 3 piping
Piping subject to localized corrosion
Impact of augmented inspection programs on the selection of pipe segments for RI-ISI
Guidance for selecting individual welds for inspection within a group of welds
Reinspection sample size

In its RR the licensee has chosen to base its selection of pipe segments on the code case. This code case is not approved for use. The code case has adopted a pipe selection procedure which differs from that in the EPRI TR. While the approach adopted by the Code Case may or may not be more conservative than that adopted by the EPRI TR, the change in risk evaluation required by the code case, and described elsewhere in this SE, mandates that the increase in risk (CDF and LERF), as compared to the current Code requirements, for any given system cannot exceed 1 x 0^{-7} and 1 x 10^{-8} per year and that the total increase in CDF and LERF may not exceed 1 x 10^{-6} and 1 x 10^{-7} per year. The NRC staff finds the approach used in the code case and by the licensee to be acceptable because the CDF and LERF associated with the piping under consideration is generally lower and in no case is significantly greater than the risk currently accepted when the existing code requirements are used.

In addition to the information regarding the number of welds to be inspected, the EPRI TR contains information concerning additional criteria to be considered when selecting welds for inspection. The EPRI TR states that licensees should consider:

Plant specific service history
Predicted severity of postulated damage mechanisms
Configuration/accessibility of element to enable effective examination
Radiation exposure
Stress concentration
Physical access to element

The code case also contains additional information for consideration in weld selection. This list includes:

Plant specific cracking experience
Weld repairs
Random selection
Minimization of worker exposure

Additionally, the code case contains requirements that inspection locations be divided among the systems under consideration and that certain percentages of inspections will be conducted in specific locations. In its RR the licensee has addressed these issues. The staff finds this acceptable because the information provided in the RR is consistent with that required by the EPRI TR and the code case.

The NRC staff reviewed the tables provided in the RR which address degradation mechanisms, failure potential and the number of welds selected for evaluation. The NRC staff finds that the data contained in these tables is consistent with the requirements of the EPRI TR.

2.2.7 Risk Impact Assessment

The licensee uses a change in risk estimation process approved by the NRC staff in the EPRI TR. The change in risk assessment in the EPRI TR permits using each segment's CCDP and CLERP or, alternatively, placing each segment into high-, medium-, or low-consequence "bins" and using a single bounding CCDP and CLERP for all segments in each consequence bin. N-716 also includes both alternatives, and the bounding values to be used in the bounding analysis are the same as those approved for use in the EPRI TR. The licensee uses the alternative of placing each segment into consequence bins and using the associated bounding values for all segments in each bin during the change in risk assessment.

In its November 12, 2010 letter the licensee states that there have been no plant changes since the previous approval of CNP's Risk-Informed Inservice Inspection Program that have added piping segments leading to changes in CDF or LERF greater than 1E-6 per year or 1E-7 per year, respectively. Calculations comprising the Internal Flooding Analysis were completed in mid-2006. Since that time, a small number of plant modifications with possible flooding implications have been identified and evaluated for PRA impact. Qualitative evaluations of these plant changes concluded that there would be minimal numerical impact to the PRA flooding model.

For the third interval, the licensee identified the different types of pipe failures that cause major plant transients such as those causing loss-of-coolant accidents and corresponding types of feedwater and steam piping breaks. Conservative CCDP estimates were developed from the PRA for these initiating events. The NRC staff concluded that the scenarios described are reasonable because they are modeled in the PRA or include the appropriate equipment failure modes that cause each sequence to progress.

The licensee relied on its flooding analysis to identify the appropriate consequence bin for welds whose failure does not cause a major plant transient and for which a consequence estimate is required. As discussed above, the licensee performed its flooding analysis consistent with ASME RA-Sb-2005. The licensee stated that its flooding analysis did identify high consequence segments (lower bound CCDP and CLERP of 1E-4 and 1E-5, respectively) for LSS Class 2 piping that was being inspected under the ASME ISI program. One scenario was reduced below the guideline value reflecting a plant change in the analysis. The second scenario was reduced below the guideline values based on a more detailed analysis of the human error probabilities. Only segments with locations at which an inspection is being discontinued need to be included in the change in risk calculation so limiting the consequence evaluation to segments that are inspected is acceptable.

Section 5 in N-716 requires that any piping that has NDE inspections[1] added or removed per N-716 be included in the change in risk assessment. The licensee used nominally the upper-bound estimates for CCDP and CLERP. Acceptance criteria provided in Section 5(d) in N-716 include limits of 1E-7/year and 1E-8/year for increase in CDF and LERF for each system, and limits of 1E-6/year and 1E-7/year for the total increase in CDF and LERF associated with replacing the ASME Code, Section XI program with the RIS_B program. These guidelines and guideline values are consistent with those approved by the NRC staff in the EPRI TR and are, therefore, acceptable.

The change in risk evaluation approved in the EPRI TR method is a final screening to ensure that a licensee replacing the Section XI program with the risk-informed alternative evaluates the potential change in risk resulting from that change and implements it only upon determining with reasonable confidence that any increase in risk is small and acceptable. The licensee's method is consistent with the approved EPRI TR method with the exception that the change in risk calculation in N-716 includes the risk increase from discontinued inspection in LSS locations. CCDP and CLERP values greater than 1E-4 and 1E-5 were used for LSS welds to bound plant internal flooding study results. These values used for CCDP and CLERP were determined based on results from the plant internal flooding study and are conservatively applied as an upper bound for all LSS welds. In lieu of conducting a formal degradation mechanism evaluation for all LSS piping (e.g., thermal fatigue), these locations were conservatively assigned to the medium failure potential category for use in the change in risk assessment. The high failure potential category is not applicable since a review was conducted to ascertain LSS piping is not susceptible to FAC or water hammer. The NRC staff concludes that the licensee's method described in the third interval

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[1]Code Case N-716 requires no estimated risk increase for discontinuing surface examinations at locations that are not susceptible to outside diameter attack [e.g., external chloride stress-corrosion cracking]. The NRC staff determined during the review and approval of the EPRI TR that the surface exams do not appreciably contribute to safety and need not be included in the change in risk quantification and, therefore, exclusion of surface examinations from the change in risk evaluations is acceptable.

submittal is acceptable because the deviation from the approved EPRI TR method expands the scope of the calculated change in risk.

The licensee provided the results of the change in risk calculations in the current submittal and noted that the results indicate a decrease in risk and that all the estimates satisfy both the system level and the total guidelines. Therefore, the NRC staff finds that any decrease in risk is acceptable.

2.2.8 Implementation Monitoring and Feedback

Section 6.2.3 of the EPRI TR addresses implementation, performance monitoring and corrective action strategies. This section does not contain sufficient information to be useful as an evaluation tool. However, this section states that there are no unique aspects of the EPRI method that would suggest a need to depart from any of the requirements of Element 3 of RG 1.178. Element 3 of RG 1.178 will, therefore, be used to evaluate this aspect of the request.

Element 3 of RG 1.178 is divided into three categories: program implementation, performance monitoring, and corrective actions. The program implementation category requires that a licensee's RI-ISI program have a schedule for inspecting all piping segments categorized as safety significant. It further states that the inspection interval will normally be that prescribed by Section XI of the Code but that certain degradation mechanisms may require the interval to be altered. The performance monitoring category requires that a licensee's RI-ISI program be updated based on: changes in plant design features, changes in plant procedures, equipment performance changes, examination results, and plant or industry operating experience. Additionally, a licensee must update its program periodically to correspond to the requirements contained in Section XI of the Code, Inspection Program B. The corrective action category requires a corrective action program that is consistent with the requirements of Section XI of the Code for both Code class and non Code class piping.

Licensee information concerning this topic was set forth in the RR, and obtained from Sections 6 and 7 of the code case. The code case information was used by the NRC in this review based on the licensee's statement that it would develop implementation procedures for its program in accordance with the code case. The licensee states that it has a corrective action program and that it will review the RI-ISI program periodically as required by the Code or more frequently as directed by the NRC, or industry or plant specific feedback. Sections 6 and 7 of the code case address inspection frequency and program updates. These sections indicate that inspection frequencies should normally be in accordance with Code requirements and that updates should be made on a Code dictated schedule or more frequently in response to plant and industry events or information.

The NRC staff finds the licensee's approach to implementing the program to be acceptable because, in accordance with RG 1.178, the licensee indicated that it inspects components on a frequency based on the Code, that it has a corrective action program, and that it updates the program periodically and in response to plant and industry events and information.

2.2.9 Examination Methods

Section 4 of the EPRI TR addresses the NDE techniques which must be used in a RI-ISI program. This section emphasizes the concept that the inspection technique utilized must be specific to the degradation mechanism expected. Table 4.1 of the EPRI TR summarizes the degradation mechanisms inspected and the examination methods which are appropriate. Specific references are provided to the Code concerning the manner in which the examination is conducted and the acceptance standard.

The code case addresses the issue of degradation mechanism/inspection technique in Table 1. Like Table 4.1 of the EPRI TR, Table 1 of the code case lists degradation mechanism and corresponding inspection techniques. This table also provides references to the Code concerning the manner in which the examination is conduced and the acceptance standard.

The licensee states that the implementation of the RI-ISI program will conform to the code case, i.e., each HSS piping segment will be assigned to the appropriate item number within Table 1 of the code case. The NRC staff finds this acceptable because proper assignment of piping segments into Table 1 will ensure that appropriate inspections to detect the degradation mechanism under consideration are conducted. The NRC staff finds this approach acceptable because it is consistent with the EPRI TR.

2.3 Conclusion on ISIR-4-01

Pursuant to 10 CFR 50.55a(a)(3)(i), alternatives to the requirements of 10 CFR 50.55a(g) may be used, when authorized by the NRC, if the licensee demonstrates that the proposed alternatives will provide an acceptable level of quality and safety. In this case, the licensee proposed to use an alternative to the risk-informed process described in Code Case N-716 which is based, in large part, on the NRC-approved EPRI TR-112657. The implementation strategy is consistent with the EPRI-TR guidelines because the number and location of inspections is a product of a systematic application of the risk-informed process. Other aspects of the licensee's ISI program, such as system pressure tests and visual examination of piping structural elements, will continue to be performed on all Class 1, 2, and 3 systems in accordance with ASME Code, Section XI. This provides a measure of continued monitoring of areas that are being eliminated from the NDE portion of the ISI program. As required by the EPRI TR methodology, the existing ASME Code performance measurement strategies will remain in place. In addition, the Code Case N-716 methodology provides for increased inspection volumes for those locations that are included in the NDE portion of the program.

The EPRI RI-ISI methodology contains details for developing an acceptable RI-ISI program. Code Case N-716, modified as described by the licensee in its submittals, describes a methodology similar to the EPRI methodology but with several differences as described above in this SE. The NRC staff has evaluated each of the differences and determined that the licensee's proposed methodology, when applied as described, meets the intent of all the steps endorsed in the EPRI TR, is consistent with the guidance provided in RG 1.178, and satisfies the guidelines established in RG 1.174.

All requirements, other than for which relief was specifically requested and authorized above, remain applicable, including the third party review by the authorized nuclear in-service inspector.

The NRC staff concludes that the licensee's proposed RIS_B ISI program will provide an acceptable level of quality and safety pursuant to 10 CFR 50.55a(a)(3)(i) for the proposed alternative to the piping ISI requirements with regard to (1) the number of locations, (2) the locations of inspections, and (3) the methods of inspection. Therefore, the proposed RI-ISI program is authorized for the fourth 10-year ISI interval pursuant to 10 CFR 50.55a(a)(3)(i) on the basis that this alternative will provide an acceptable level of quality and safety.

3.0 RELIEF REQUEST ISIR-4-02

3.1 Regulatory Evaluation

The requirements at 10 CFR 50.55a(g) specify that ISI of ASME Code Class 1, 2, and 3 components be performed in accordance with Section XI of the ASME Code and applicable addenda, except where specific written relief has been granted by the Commission pursuant to 10 CFR 50.55a(g)(6)(i). According to 10 CFR 50.55a(a)(3), alternatives to the requirements of paragraph 50.55a(g) may be used, when authorized by the Nuclear Regulatory Commission (NRC), if an applicant demonstrates that the proposed alternatives would provide an acceptable level of quality and safety or if the specified requirement 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 preservice examination requirements, set forth in the ASME Code, Section XI, "Rules for Inservice Inspection (ISI) of Nuclear Power Plant Components," to the extent practical within the limitations of design, geometry, and materials of construction of the components. The regulations require that ISI of components and system pressure tests conducted during the first 10-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 the limitations and modifications listed therein. The ISI Code of Record for the fourth 10-year inspection interval of CNP Units 1and 2, is the 2004 Edition of the ASME Code, Section XI, no addenda.

3.2 Technical Evaluation

The licensee requested this relief for the components listed in the following table:

Pipe Segment Description	NPS Diameter	Piping Material
Valves 1/2-IMO-315 to 1/2-SI-158-L1/L4 Hot Leg Injection	8" to 6"	SA-376 Grade TP 316 Seamless Austenitic Steel Sch. 140
Valves 1/2-SI-161-L1/L4 to ECCS Cold Leg Injection	6"	SA-376 Grade TP 316 Seamless Austenitic Steel Sch. 140
Valves 1/2-SI-166-L1/L2/L3/L4 to 1/2-SI-170-L1/L2/L3/L4 Cold Legs	10"	SA-376 Grade TP 316 Seamless Austenitic Steel Sch. 140
Valves 1/2-SI-238-L1/L2/L3/L4, 1/2-SI-167-L1/L2/L3/L4 to Accumulator Discharge Line	¾"	SA-376 Grade TP 316 Seamless Austenitic Steel Sch. 140
Valves 1/2-SI-161-L2/L3 to ECCS Cold Leg Injection	6"	SA-376 Grade TP 316 Seamless Austenitic Steel Sch. 140
Valves 1/2-RH-134 to Cold Leg Injection L3	8"	SA-376 Grade TP 316 Seamless Austenitic Steel Sch. 140
Valves 1/2-RH-133 to Cold Leg Injection L2	8"	SA-376 Grade TP 316 Seamless Austenitic Steel Sch. 140
Valves 1/2-IMO-325 to 1/2-SI-158-L2/L3 Hot Leg Injection	8" to 6"	SA-376 Grade TP 316 Seamless Austenitic Steel Sch. 140

Table IWB-2500-1, Category B-P, Item Number B15.10, requires all Class 1 pressure retaining components be subject to a system leakage test with a VT-2 visual examination in accordance with Paragraph IWB-5220. This pressure test is to be conducted prior to plant startup following each reactor refueling outage. The pressure retaining boundary for the test conducted at or near the end of each inspection interval shall be extended to all Class 1 pressure retaining components per Paragraph IWB-5222(b).

CNP's nominal reactor coolant pressure at 100 percent rated power is approximately 2060 pounds per square inch guage (psig) for Unit 1 and 2210 psig for Unit 2. The piping segments noted in the above table are separated by an inboard check valve from the Reactor Coolant System (RCS) and therefore, are not exposed to a pressure of 2060 psig for Unit 1 and 2210 psig for Unit 2. The piping for the safety injection system is pressurized to approximately 625 psig at Unit 1 and approximately 615 psig at Unit 2 during normal plant operating conditions from the upstream injection accumulators. The piping segments from the Residual Heat Removal (RHR) system to the inboard check valve are pressurized to approximately 600 psig during reactor start-up following the refueling outage.

Based on these considerations, the licensee believes that compliance with the ASME Section XI Code requirements stated would result in hardship and unusual difficulty without a compensating increase in the level of quality and safety.

The licensee stated that the piping segments found in the table above are visually examined (VT-2) during each refueling outage with the reactor coolant system at nominal operating pressure and nominal operating temperature (NOP/NOT) and the inboard isolation valves normally closed. This examination is conducted in accordance with ASME Code Section XI, Table IWB-2500-1 Examination Category B-P, Item Number B15.10. This test is part of the Class 1 system leakage test with the valves positioned in their normal alignment. This examination is proposed as an alternative to the ASME Code Section XI, Table IWB-2500-1 Examination Category B-P, Item Number B15.10.

The licensee stated that the piping segments in the table above for the RHR are visually examined during plant start-up following each refueling outage with the RHR pumps taking suction from the RCS at less than approximately 435 psig. The safety injection lines listed in the table are pressurized to approximately 625 psig at Unit 1 and approximately 615 psig at Unit 2 during normal plant operating condition from the upstream injection accumulators. The safety injection accumulators have level and pressure alarms located in the control room for both units. If there is any indication of RCS leakage from these segments (level or pressure loss) it would be denoted by alarms located in the control room. The licensee's operating procedures set in motion multiple actions, including an operator to be dispatched to the location of the incident. Current Technical Specifications require verification of level and pressure of the accumulators by monitoring controls and logging the conditions at least once every 12 hours.

The piping segments noted in the table above contain stainless steel pipe, valves, and weld material. These items do not contain any alloy 600/82/182 materials. CNP currently has no known degradation mechanisms taking place in these piping segments. The piping segments that continue beyond the last check valve to the RCS loops are also constructed of the same material and specifications. These Class 1 segments are exposed to the RCS pressure and VT-2 examined during the system leakage test conducted at the end of each refueling outage (NOP/NOT).

The ASME Code requires that a system leakage test be performed at the end of each refueling outage, and when performed at or near the end of the interval, the test must include all Class 1 components within the RCS boundary. The system leakage test must be performed at a test pressure not less than the nominal operating RCS pressure corresponding with 100 percent rated reactor power. However, several safety injection (SI) and RHR pipe segments are connected to the RCS through self-actuating check valves, which do not allow normal RCS pressure to be used to pressurize these segments. In order to test the subject piping segments to normal operating RCS pressure, the licensee would have to make plant design modifications. To require the licensee to make plant modifications in order to pressurize the subject line segments to normal RCS pressure would result in a considerable hardship.

As an alternative to pressurizing the subject line segments to approximately 2060 psig for Unit 1 and 2210 psig for Unit 2 (RCS pressure at 100 percent rated power), the licensee proposed to perform system leakage test at 625 psig for Unit 1 and at 615 psig for Unit 2, the normal operating pressure of the SI system accumulators and at less than approximately 435 psig for the RHR segments.

The licensee's proposed alternative represents the highest test pressures that can be obtained without the modifications and are intended to test the subject pipe segments to conditions similar to those that may be experienced during postulated design basis events. The licensee expects that the proposed test pressures will be sufficient to produce detectable leakage from significant service-induced degradation sources, if any. The NRC staff determined that the licensee's proposed alternative would provide reasonable assurance of operational readiness and structural integrity of the subject pipe segments and is, therefore, acceptable.

3.3 Conclusion on Relief Request ISIR-4-02

As set forth above, the NRC staff concludes that the licensee provided sufficient technical basis to find that compliance with the current requirements would cause an unnecessary burden on the licensee without a compensating increase in the level of quality and safety. Therefore, the licensee's proposed alternative identified as Relief Request ISIR-4-02 is authorized pursuant to 10 CFR 50.55a(a)(3)(ii) for the fourth 10-year ISI interval at Donald C. Cook Nuclear Plant, Units 1 and 2.

All other ASME Code, Section XI requirements for which relief was not specifically requested and approved in the subject request for relief remain applicable, including third-party review by the Authorized Nuclear Inservice Inspector.

4.0 RELIEF REQUEST ISIR-4-03

4.1 Regulatory Evaluation

The requirements at 10 CFR 50.55a(g) specify that ISI of ASME Code Class 1, 2, and 3 components be performed in accordance with Section XI of the ASME Code and applicable addenda, except where specific written relief has been granted by the Commission pursuant to 10 CFR 50.55a(g)(6)(i). According to 10 CFR 50.55a(a)(3), alternatives to the requirements of paragraph 50.55a(g) may be used, when authorized by the NRC, if an applicant demonstrates that the proposed alternatives would provide an acceptable level of quality and safety or if the specified requirement 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 preservice examination requirements, set forth in the ASME Code, Section XI, "Rules for Inservice Inspection (ISI) of Nuclear Power Plant Components," to the extent practical within the limitations of design, geometry, and materials of construction of the components. The regulations require that ISI of components and system pressure tests conducted during the first 10-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 the limitations and modifications listed therein. The ISI Code of Record for the fourth 10-year inspection interval of CNP Units 1and 2, is the 2004 Edition of the ASME Code, Section XI, no addenda.

4.2 Technical Evaluation

The licensee requested relief for the following component:

Pipe Segment Description	NPS Diameter	Piping Material
Valves 1/2-IMO-128 to 1/2-ICM-129 Hot Leg for Cooldown	14"	SA-376 Grade TP 316 Seamless Austenitic Steel Sch. 140

Table IWB-2500-1, Category B-P, Item Number B15.10, requires all Class 1 pressure-retaining components be subject to a system leakage test with a VT-2 visual examination in accordance with Paragraph IWB-5220. This pressure test is to be conducted prior to plant startup following each reactor refueling outage. The pressure-retaining boundary for the test conducted at or near the end of each inspection interval shall be extended to all Class 1 pressure retaining components per Paragraph IWB-5222(b).

The primary function of the Residual Heat Removal (RHR) System is to remove decay heat energy from the reactor core to the Component Cooling Water (CCW) System via the RHR heat exchangers during the second phase of plant cool down during shutdown and refueling operations. It is designed to only perform this function once the Reactor Cooling System (RCS) temperature and pressure is reduced to below the RHR design limits.

CNP's normal reactor coolant pressure at 100 percent rated power is approximately 2060 psig for Unit 1 and 2210 psig for Unit 2. The Class 1 RCS pressure boundary extends to the second isolation valve (ICM-129) downstream from the RCS. The section of piping between the two isolation valves noted in the table above has the same design pressure as the RCS. However, this piping is isolated from the RCS by two motor-operated valves in series and the remainder of the RHR suction line is not exposed to pressure of 2060 psig for Unit 1 and 2210 psig for Unit 2. Both valves have interlock set-points that require RCS pressure to be below 424.5 psig prior to the valves being opened.

On the other hand, as the RCS pressure and temperature increases to nominal operating pressure and temperature, the two motor-operated valves are closed in accordance with plant procedures when the RCS pressure exceeds 506.25 psig. Therefore, the RCS pressure and temperature at 100 percent rated power is isolated from the piping segments between these valves.

CNP design configuration of the RCS meets the requirements of double valve isolation defined in 10 CFR 50.55a(c)(2)(ii), but cannot satisfy the code requirements of ASME Code, Section XI, 2004 Edition, Paragraph IWB-5221(a). Opening the RCS inlet isolation valve contradicts the philosophy of 10 CFR 50.55a(c)(2)(ii) between the Class 1 and Class 2 boundaries of the RHR system.

The licensee stated that piping segments found in the above table are visually examined (VT-2) during each refueling outage during normal Class 1 walkdowns at nominal operating pressure and nominal operating temperature (NOP/NOT). This examination is conducted in accordance with ASME Code Section XI, Table IWB-2500-1 Examination Category B-P, Item Number B15.10. This test is part of the Class 1 system leakage test with the valves positioned in their normal alignment (i.e. both valves closed).

Additionally, the licensee proposed that the pipe segment between IMO-128 and ICM-129 be visually examined (VT-2) as part of the Class 2 system pressure test performed once every inspection period according to ASME Code Section XI, Table IWC-2500-1 Examination Category C-H, Item Number C7.10.

The licensee stated that if through-wall leakage were to occur in these piping segments, the proposed alternative examinations would identify any leakage.

The piping segments noted in the table above contain stainless steel pipe, valves, and weld material. These items do not contain any alloy 600/82/182 materials. The licensee stated that CNP currently has no known degradation mechanisms taking place in these piping segments.

The piping downstream of the RCS up to the inlet valves are constructed of the same material specifications as the segment of piping listed in Table 1. These Class 1 segments are exposed to the RCS pressure and are VT-2 examined during the system leakage test conducted at the end of each refueling outage during NOP/NOT.

The ASME Code requires that a system leakage test be performed at the end of each refueling outage, and when performed at or near the end of the interval, the test must include all Class 1 components within the RCS boundary. The system leakage test must be performed at a test pressure not less than the nominal operating RCS pressure corresponding with 100 percent rated reactor power. However, the RHR piping segment, located between two interlocked MOVs, does not allow normal RCS pressure to be used to pressurize the segment. In order to test the subject piping segments to normal operating RCS pressure (approximately 2060 psig Unit 1 and 2210 psig Unit 2), the licensee would have to make plant design modifications. To require the licensee to make plant modifications in order to pressurize the subject line segments to normal RCS pressure would result in a considerable hardship.

The licensee has proposed to perform the VT-2 visual examination for leakage during system leakage testing each refueling outage with the valves in their normal system alignment. Additionally, these piping segments will be visually examined (VT-2) for leakage as part of the Class 2 system pressure test performed once every inspection period using the Class 2 test requirement.

The licensee's proposed alternative represents the highest test pressures that can be obtained without modifications and are intended to test the subject pipe segments to conditions similar to those that may be experienced during postulated design basis events. It is expected that the proposed test pressures will be sufficient to produce detectable leakage from significant service-induced degradation sources, if any. The NRC staff has determined that the licensee's proposed alternative would provide reasonable assurance of operational readiness and structural integrity of the subject pipe segments and is, therefore, acceptable.

4.3 Conclusion on Relief Request ISIR-4-03

As set forth above, the NRC staff concludes that the licensee provided sufficient technical basis to find that compliance with the current requirements would cause an unnecessary burden on the licensee without a compensating increase in the level of quality and safety. Therefore, the licensee's proposed alternative identified as Relief Request ISIR-4-03 is authorized pursuant to 10 CFR 50.55a(a)(3)(ii) for the fourth 10-year ISI interval at CNP, Units 1 and 2.

All other ASME Code, Section XI requirements for which relief was not specifically requested and approved in the subject request for relief remain applicable, including third-party review by the Authorized Nuclear Inservice Inspector.

5.0 RELIEF REQUEST ISIR-4-04

5.1 Regulatory Evaluation

The requirements at 10 CFR 50.55a(g) specify that ISI of ASME Code Class 1, 2, and 3 components be performed in accordance with Section XI of the ASME Code and applicable addenda, except where specific written relief has been granted by the Commission pursuant to 10 CFR 50.55a(g)(6)(i). According to 10 CFR 50.55a(a)(3), alternatives to the requirements of paragraph 50.55a(g) may be used, when authorized by the Nuclear Regulatory Commission (NRC), if an applicant demonstrates that the proposed alternatives would provide an acceptable level of quality and safety or if the specified requirement 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 preservice examination requirements, set forth in the ASME Code, Section XI, "Rules for Inservice Inspection (ISI) of Nuclear Power Plant Components," to the extent practical within the limitations of design, geometry, and materials of construction of the components. The regulations require that ISI of components and system pressure tests conducted during the first 10-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 the limitations and modifications listed therein. The ISI Code of Record for the fourth 10-year inspection interval of CNP Units 1and 2, is the 2004 Edition of the ASME Code, Section XI, no addenda.

5.2 Technical Evaluation

The licensee requested this relief for the components listed in the following table:

Segments	Description	Inboard Valve Normally Closed?
1	Safety Injection Valve	Yes
2	Safety Injection Valve	Yes
3	Safety Injection Valve	Yes
4	Safety Injection Valve	Yes
5	Safety Injection Valve	Yes
6	Safety Injection Valve	Yes
7	Safety Injection Valve	Yes
8	Safety Injection Valve	Yes
9	Safety Injection Valve	Yes
10	Safety Injection Valve	Yes
11	Residual heat Removal Drain	Yes
12	Safety Injection Accumulator Vent	Yes
13	Safety Injection Accumulator Vent	Yes
14	Safety Injection Accumulator Vent	Yes
15	Safety Injection Accumulator Vent	Yes
16	Pressurizer Vent to Atmosphere	Yes
17	Mid-Loop Monitoring Transmitter	Yes
18	Half-Loop Operation Transmitter	Yes
19	Half-Loop Operation Transmitter	Yes
20	Cold Leg Drain Line to Reactor Coolant Drain Tank	Yes
21	Cold Leg Drain Line to Reactor Coolant Drain Tank	Yes
22	Cold Leg Drain Line to Reactor Coolant Drain Tank	Yes
23	Cold Leg Drain Line to Reactor Coolant Drain Tank	Yes

Table IWB-2500-1, Category B-P, Item Number B15.10, requires all Class 1 pressure-retaining components be subject to a system leakage test with a VT-2 visual examination in accordance with Paragraph IWB-5220. This pressure test is to be conducted prior to plant startup following each reactor refueling outage. The pressure retaining boundary for the test conducted at or near the end of each inspection interval shall be extended to all Class 1 pressure retaining components per Paragraph IWB-5222(b).

The licensee stated that CNP's nominal reactor coolant pressure at 100 percent rated power is approximately 2060 psig for Unit 1 and 2210 psig for Unit 2. The vent, drain, and instrument connections within the Class 1 boundary consist of pipe segments that contain either two manually operated valves in series or a manually operated valve and an end cap or blank flange that provides the design requirement for double isolation. The isolation valves on these vent and drain lines are generally in close proximity to the process pipe and there is minimum distance between the first and second valves. During normal plant operation, each pipe segment's isolation valves are maintained in the closed or locked closed position, and the piping downstream of the first isolation valve is not normally pressurized.

While in Mode 3 during plant start-up, the system leakage test is performed with the Reactor Coolant System (RCS) at full pressure, approximately 2060 psig at Unit 1 and 2210 psig at Unit 2, and normal operating temperature greater than 500°F. Testing the small diameter Class 1 vent, drain, and instrument connections would require an operator to change valve positions with the RCS at Nominal Operating Pressure and Nominal Operating Temperature (NOP/NOT). These valve manipulations would need to be performed under elevated containment air temperature and humid conditions.

Furthermore, due to the location of many of these valves, it would be necessary to erect scaffolding for this evolution. The licensee estimated that the expected dose for performing these activities to be between 400 milirem (mrem) and 700 mrem for Unit 1 and between 450 mrem and 800 mrem for Unit 2. Finally, in Mode 3 during plant start-up (NOP/NOT), the system leakage test is conducted as a critical-path evolution. The valve manipulations necessary to pressurize the isolated portions of the vent, drain, and instrument connections, and then to return them to normal position would directly impact the start-up activity sequence and outage duration.

The licensee proposed that the small diameter vent, drain and instrument connections, 1 inch and less as well as four 2 inch RCS drain lines be visually examined (VT-2) at the end of each refueling outage with the isolation valves in their normal closed position and the system at the NOP/NOT for the system leakage test. This examination is conducted in accordance with ASME Code Section XI, Table IWB-2500-1 Examination Category B-P, Item Number B15.10.

The licensee stated that the non-isolable portion of the RCS will be pressurized and visually examined as required. The isolated portion of the small-diameter vent, drain, and instrument connections will be visually examined in the same configuration as during normal operation. The examination is part of the Class 1 system leakage test with the valves positioned in their normal alignment.

In addition, during normal operation, the licensee stated that the RCS will be monitored for leakage in accordance with the requirements of the applicable Technical Specifications, and that corrective actions for any identified leakage under this monitoring will be performed in accordance with the requirement specified by the Technical Specification.

The NRC staff notes that the ASME Code requires that a system leakage test be performed at the end of each refueling outage, and when performed at or near the end of the interval, the test must include all Class 1 components within the RCS boundary. The system leakage test must be performed at a test pressure not less than the nominal operating RCS pressure corresponding with 100 percent rated reactor power.

In order for the licensee to perform the ASME Code-required test, it would be necessary to manually open the inboard valves to pressurize the pipe segments. Pressurization by this method would preclude the RCS double-valve isolation and may cause safety concerns for the personnel performing the examination. Typical line/valve configurations are in close proximity of the RCS main run of pipes, and thus, would require personnel entry into high radiation areas within the containment. Since most of the valves are inaccessible, temporary scaffolding has to be erected to reposition the valves. Manual operation of these valves was estimated by the licensee to expose plant personnel to considerable radiation doses.

The licensee proposed a visual examination (VT-2) for leaks in the isolated portion of the subject segments of piping with the isolation valves in the normally closed position, which would show any evidence of past leakage. Also, the non-isolable portion of the RCS will be pressurized and visually examined as required. The NRC staff believes that the licensee's proposed alternative will provide reasonable assurance of operational readiness for the subject line segments while keeping personnel radiation exposure as low as reasonably achievable. The NRC staff has determined that compliance with the Code requirements would result in hardship or unusual difficulty without a compensating increase in the level of quality and safety.

5.3 Conclusion on Relief Request ISIR-4-04

As set forth above, the NRC staff concludes that the licensee provided sufficient technical basis to find that compliance with the current requirements would cause an unnecessary burden on the licensee without a compensating increase in the level of quality and safety. Therefore, the licensee's proposed alternative identified as Relief Request ISIR-4-04 is authorized pursuant to 10 CFR 50.55a(a)(3)(ii) for the fourth 10-year ISI interval at CNP, Units 1 and 2.

All other ASME Code, Section XI requirements for which relief was not specifically requested and approved in the subject request for relief remain applicable, including third-party review by the Authorized Nuclear Inservice Inspector.

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Date: March 30, 2011

If you have any questions, please contact the Project Manager Mr. Peter Tam at (301) 415-1451.

Sincerely,

/RA/

Robert J. Pascarelli, Chief
Plant Licensing Branch III-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. 50-315 and 50-316

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