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

October 27, 2011

Mr. Mark A. Schimmel
Site Vice President
Prairie Island Nuclear Generating Plant
Northern States Power Company - Minnesota
1717 Wakonade Drive East
Welch, MN 55089-9642

SUBJECT: PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNITS 1 AND 2 - ISSUANCE OF AMENDMENTS RE: REQUEST TO EXCLUDE THE DYNAMIC EFFECTS ASSOCIATED WITH CERTAIN POSTULATED PIPE RUPTURES FROM THE LICENSING BASIS BASED UPON APPLICATION OF LEAK-BEFORE-BREAK METHODOLOGY (TAC NOS. ME2976 AND ME2977)

Dear Mr. Schimmel:

The U.S. Nuclear Regulatory Commission has issued the enclosed Amendment No. 204 to Renewed Facility Operating License No. DPR-42 and Amendment No. 191 to Renewed Facility Operating License No. DPR-60 for the Prairie Island Nuclear Generating Plant (PINGP), Units 1 and 2, respectively.

The amendments consist of changes to the PINGP Updated Final Safety Analysis Report in response to your application dated December 22, 2009 (Agencywide Documents and Access Management System (ADAMS) Accession No. ML100200129), as supplemented by letters dated July 23, August 20, October 8, 2010, and January 14, February 23, April 6, and August 9, 2011 (ADAMS Accession Nos. ML102040612, ML102320535, ML102810518, ML110140367, ML110550582, ML110970101, and ML112220099, respectively).

A copy of our related safety evaluation is also enclosed. The Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,

Thomas J. Wengert, Senior Project Manager
Plant Licensing Branch III-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. 50-282 and 50-306

Enclosures:
1. Amendment No. 204 to DPR-42
2. Amendment No. 191 to DPR-60
3. Safety Evaluation

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

NORTHERN STATES POWER COMPANY - MINNESOTA

DOCKET NO. 50-282

PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNIT 1

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No.204
License No. DPR-42

1. The U.S. Nuclear Regulatory Commission (NRC, the Commission) has found that:

   A. The application for amendment by Northern States Power Company, a Minnesota Corporation (NSPM, the licensee), dated December 22, 2009, as supplemented by letters dated July 23, August 20, October 8, 2010, and January 14, February 23, April 6, and August 9, 2011, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Prairie Island Nuclear Generating Plant, Units 1 and 2, Updated Safety Analysis Report (USAR) and as indicated in the attachment to this license amendment. Paragraph 2.C.(2) of Renewed Facility Operating License No. DPR-42 is hereby amended to read as follows:

Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 204 , are hereby incorporated in the renewed operating license. NSPM shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of the date of its issuance and shall be implemented within 180 days. In addition, the licensee shall include the revised information in the Prairie Island Nuclear Generating Plant (PINGP), Units 1 and 2, USAR in the next periodic update to the USAR in accordance with 10 CFR 50.71(e), of the changes to the description of the facility as described in the PINGP, Units 1 and 2, application dated December 22, 2009, as supplemented by letters dated July 23, August 20, October 8, 2010, and January 14, February 23, April 6, and August 9, 2011, and the NRC staff's safety evaluation for this amendment.

FOR THE NUCLEAR REGULATORY COMMISSION

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

Attachment: Changes to the Renewed
Facility Operating License

Date of Issuance: October 27, 2011

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

NORTHERN STATES POWER COMPANY - MINNESOTA

DOCKET NO. 50-306

PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNIT 2

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 191
License No. DPR-60

1. The U.S. Nuclear Regulatory Commission (NRC, the Commission) has found that:

   A. The application for amendment by Northern States Power Company, a Minnesota Corporation (NSPM, the licensee), dated December 22, 2009, as supplemented by letters dated July 23, August 20, October 8, 2010, and January 14, February 23, April 6, and August 9, 2011, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Prairie Island Nuclear Generating Plant, Units 1 and 2, Updated Safety Analysis Report (USAR) and as indicated in the attachment to this license amendment. Paragraph 2.C.(2) of Renewed Facility Operating License No. DPR-60 is hereby amended to read as follows:

Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 191 , are hereby incorporated in the renewed operating license. NSPM shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of the date of its issuance and shall be implemented before the end of the next scheduled Unit 2 refueling outage. In addition, the licensee shall include the revised information in the Prairie Island Nuclear Generating Plant (PINGP), Units 1 and 2, USAR in the next periodic update to the USAR in accordance with 10 CFR 50.71(e), of the changes to the description of the facility as described in the PINGP, Units 1 and 2, application dated December 22, 2009, as supplemented by letters dated July 23, August 20, October 8, 2010, and January 14, February 23, April 6, and August 9, 2011, and the NRC staff's safety evaluation for this amendment.

FOR THE NUCLEAR REGULATORY COMMISSION

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

Attachment: Changes to the Renewed
Facility Operating License

Date of Issuance: October 27, 2011

ATTACHMENT TO LICENSE AMENDMENT NOS. 204 AND 191

RENEWED FACILITY OPERATING LICENSE NOS. DPR-42 AND DPR-60

DOCKET NOS. 50-282 AND 50-306

Replace the following pages of the Renewed Facility Operating License No. DPR-42 and DPR-60 with the attached revised pages. The changed areas are identified by a marginal line.

REMOVE	INSERT
DPR-42, License Page 3	DPR-42, License Page 3
DPR-60, License Page 3	DPR-60, License Page 3

(3) Pursuant to the Act and 10 CFR Parts 30, 40 and 70, NSPM to receive, possess, and use at any time any byproduct, source and special nuclear material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

(4) Pursuant to the Act and 10 CFR Parts 30, 40, and 70, NSPM to receive, possess and use in amounts as required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument and equipment calibration or associated with radioactive apparatus or components;

(5) Pursuant to the Act and 10 CFR Parts 30 and 70, NSPM to possess but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility;

(6) Pursuant to the Act and 10 CFR Parts 30 and 70, NSPM to transfer byproduct materials from other job sites owned by NSPM for the purpose of volume reduction and decontamination.

C. This renewed operating license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations in 10 CFR Chapter I: Part 20, Section 30.34 of Part 30, Sections 50.54 and 50.59 of Part 50, and Section 70.32 of Part 70; is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

NSPM is authorized to operate the facility at steady state reactor core power levels not in excess of 1677 megawatts thermal.

(2) Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 204, are hereby incorporated in the renewed operating license. NSPM shall operate the facility in accordance with the Technical Specifications.

(3) Physical Protection

NSPM shall fully implement and maintain in effect all provisions of the Commission-approved physical security, guard training and qualification, and safeguards contingency plans including amendments made pursuant to provisions of the Miscellaneous Amendments and Search Requirements revisions to 10 CFR 73.55 (51 FR 27817 and 27822) and to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The combined set of plans, which contains

(3) Pursuant to the Act and 10 CFR Parts 30, 40 and 70, NSPM to receive, possess, and use at any time any byproduct, source and special nuclear material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

(4) Pursuant to the Act and 10 CFR Parts 30, 40, and 70, NSPM to receive, possess and use in amounts as required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument and equipment calibration or associated with radioactive apparatus or components;

(5) Pursuant to the Act and 10 CFR Parts 30 and 70, NSPM to possess but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility;

(6) Pursuant to the Act and 10 CFR Parts 30 and 70, NSPM to transfer byproduct materials from other job sites owned by NSPM for the purposes of volume reduction and decontamination.

C. This renewed operating license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations in 10 CFR Chapter I: Part 20, Section 30.34 of Part 30, Sections 50.54 and 50.59 of Part 50, and Section 70.32 of Part 70; is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

NSPM is authorized to operate the facility at steady state reactor core power levels not in excess of 1677 megawatts thermal.

(2) Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 191, are hereby incorporated in the renewed operating license. NSPM shall operate the facility in accordance with the Technical Specifications.

(3) Physical Protection

NSPM shall fully implement and maintain in effect all provisions of the Commission-approved physical security, guard training and qualification, and safeguards contingency plans including amendments made pursuant to provisions of the Miscellaneous Amendments and Search Requirements revisions to 10 CFR 73.55 (51 FR 27817 and 27822) and to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The combined set of plans, which contains

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

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO

AMENDMENT NO. 204 TO RENEWED FACILITY OPERATING LICENSE NO. DPR-42

AND AMENDMENT NO. 191 TO RENEWED FACILITY OPERATING LICENSE NO. DPR-60

NORTHERN STATES POWER COMPANY - MINNESOTA

PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNITS 1 AND 2

DOCKET NOS. 50-282 AND 50-306

1.0 INTRODUCTION

By letter dated December 22, 2009 (Agencywide Documents and Access Management System (ADAMS) Accession No. ML100200129), to the U.S. Nuclear Regulatory Commission (NRC, the Commission) Northern States Power Company, doing business as Xcel Energy (the licensee), submitted a license amendment request (LAR) to allow implementation of the leak-before-break (LBB) methodology on certain reactor coolant system (RCS) branch piping at Prairie Island Nuclear Generating Plant (PINGP), Units 1 and 2. The list of candidate piping is listed in Section 3.1 of this safety evaluation (SE).

The LBB concept is based on calculations and experimental data demonstrating that certain pipe material has sufficient fracture toughness (ductility) to prevent a small through-wall flaw from propagating rapidly and uncontrollably to catastrophic pipe rupture and to ensure that the probability of a pipe rupture is extremely low. The small leaking flaw is demonstrated to grow slowly and the limited leakage would be detected by the RCS leakage detection systems early on such that licensees can shut down the plant to repair the degraded pipe long before the potential catastrophic pipe rupture.

The licensee's technical basis for the proposed LBB LAR is based on the following three reports enclosed in the December 22, 2009, submittal. Enclosure 1 describes the proposed license amendment; Enclosure 2 is the Structural Integrity Associates (SIA) proprietary report, 0900634.401, Revision 2, (SIA-401 report), "Updated Leak-Before-Break Evaluation for Several RCS Piping at Prairie Island Nuclear Generating Plant Units 1 and 2;" Enclosure 3 is the SIA proprietary report, 0900634.402, Revision 2, (SIA-402 report), "Updated Leak-Before-Break (LBB) Report for Prairie Island Nuclear Generating Plant Unit 2 Pressurizer Surge Line Nozzle;" and Enclosure 4 is the Westinghouse Electric Company report, "Technical Justification for Eliminating Pressurizer Surge Line Rupture as the Structural Design Basis for Prairie Island Unit 2 Nuclear Plant," March 2000, WCAP-15379-P (proprietary) and WCAP-15380 (non-proprietary), which contains the original LBB analysis for the Unit 2 pressurizer surge line.

Enclosure

By letters dated July 23, August 20, October 8, 2010 and January 14, February 23, April 6, and August 9, 2011 (ADAMS Accession Nos. ML102040612, ML102320535, ML102810518, ML110140367, ML110550582, ML110970101, and ML112220099, respectively), the licensee responded to the NRC staff's requests for additional information.

Some enclosures to the December 22, 2009, letter contain proprietary information and are, therefore, withheld from public disclosure. Non-proprietary versions of these documents are included in the ADAMS package under Accession No. ML100200129.

The supplemental information dated July 23, August 20, October 8, 2010 and January 14, February 23, April 6, and August 9, 2011, contained clarifying information, did not change the scope of the December 22, 2009, application or the initial no significant hazards consideration determination, and did not expand the scope of the original *Federal Register* notice.

2.0 REGULATORY EVALUATION

General Design Criterion (GDC) 4 of Appendix A to Part 50 of Title 10 of the *Code of Federal Regulations* (10 CFR 50) states, in part, that ". . . Structures, systems, and components important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with . . . postulated accidents . . . . However, dynamic effects associated with postulated pipe ruptures may be excluded from the design basis when analyses reviewed and approved by the Commission demonstrate that the probability of a fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping."

NUREG-1061, Volume 3, "Report of the U.S. Nuclear Regulatory Commission Piping Review Committee, Evaluation of Potential for Pipe Breaks," dated November 1984, provides the technical basis for the LBB analyses.

NRC Standard Review Plan (SRP) Section 3.6.3, "Leak-Before-Break Evaluation Procedures," Revision 1, provides guidance for review of the LBB application, including guidance for determining an acceptable leakage crack and the RCS leakage detection sensitivity based on the fracture mechanics analysis. The guidance states that determination of leakage from a crack in a piping system under pressure involves uncertainties and, therefore, margins are needed. Sources of uncertainties include plugging of the leakage crack with particulate material over time, correlation of leakage rates with crack geometry, correlations of measured parameters (e.g., sump level changes or containment radiation levels) with leakage rate, and frequency and accuracy of leakage instrumentation monitoring. Section III.4 of SRP 3.6.3 states that the NRC staff evaluates the proposed leakage detection systems to determine whether they are sufficiently reliable, redundant, and sensitive so that a margin on the detection of unidentified leakage exists for through-wall flaws to support the deterministic fracture mechanics evaluation. The guidance specifies that the predicted leakage rate from the postulated leakage crack should be a factor of 10 times greater than the minimum leakage the detection system is capable of sensing unless the licensee provides justification accounting for the effects of uncertainties in the leakage measurement.

The guidance of SRP Section 3.6.3 also states that specifications for plant-specific leakage detection systems inside the containment should be equivalent to those in Regulatory Guide

(RG) 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems." General Design Criterion 30 (GDC-30) "Quality of reactor coolant pressure boundary" of Appendix A to 10 CFR Part 50 requires, in part, that means be provided for detecting and, to the extent practical, identifying the location of the source of reactor coolant leakage.

Licensees are required to submit, for NRC review and approval, a fracture mechanics evaluation of specific piping configurations to meet the requirements of GDC 4. A candidate pipe should satisfy the screening criteria of SRP, Section 3.6.3, by demonstrating that it experiences no active degradation. The candidate pipe should be demonstrated by the fracture mechanics analysis to satisfy the safety margins in SRP, Section 3.6.3. Finally, the licensee must demonstrate that the RCS leakage detection systems have the capability to detect a certain leak rate, with margins, when compared to the leak rate from the leakage flaw size of the candidate pipe. RG 1.45 provides acceptance criteria for the RCS leakage detection systems.

Regulatory Issue Summary 2010-07, "Regulatory Requirements for Application of Weld Overlays and Other Mitigation Techniques in Piping Systems Approved for Leak-Before-Break," provides guidance on updating fracture mechanics analyses for LBB piping that have welds fabricated with nickel-based Alloy 82/182 filler material.

The implementation of the LBB requires a license amendment under 10 CFR 50.90 because one or more of the criteria of 10 CFR 50.59(c)(2) applies to LBB. When the proposed LBB LAR is approved by the NRC, the licensee is required to amend its final safety analysis report to document that the LBB methodology has become a part of the licensing basis for the candidate piping.

The LBB analyses are based on calculations and experimental data demonstrating that certain pipe material has sufficient fracture toughness (ductility) to prevent a small through-wall flaw from propagating rapidly and uncontrollably to catastrophic pipe rupture and ensure the probability of pipe rupture is extremely low. The small leaking flaw is demonstrated to grow slowly and the limited leakage would be detected by the RCS leakage detection system early such that licensees would shutdown the plant to repair the pipe long before potential failure.

In RG 1.45, the NRC staff described acceptable methods of implementing this requirement with regard to the selection of leakage detection systems for the reactor coolant boundary. The regulatory position of RG 1.45, Rev. 0, is that at least three different detection methods should be employed. Two of these methods should be: (1) sump level and flow monitoring and, (2) airborne particulate radioactivity monitoring. The third method may involve either monitoring of condensate flow rate from air coolers or monitoring of gaseous radioactivity. The regulatory guide recommends that the sensitivity and response time of each leakage detection system employed for detection of unidentified leakage should be adequate to detect a leakage rate, or its equivalent, of one gallon per minute (gpm) in less than one hour.

Section 1.2, "Principal Design Criteria," of Revision 31 to the PINGP Updated Safety Analysis Report (USAR), includes the following description of the leakage detection systems:

> Positive indication in the control room of leakage of coolant from the Reactor Coolant System to the containment is provided by equipment which permits continuous monitoring of the containment air activity and humidity, and is

provided by the runoff from the condensate collecting pans under the cooling coils of the containment air cooling (fan coil) units. The basic design criterion is the detection of deviations from normal containment environmental conditions including air particulate activity, radiogas activity, humidity, condensate runoff and in addition, in the case of gross leakage, the liquid inventory in the process systems and containment sump.

The requirements related to the content of the Technical Specifications (TSs) are contained in 10 CFR 50.36, which requires that the TSs include limiting conditions for operation (LCOs). The criteria defined by 10 CFR 50.36(c)(2)(ii) relevant to determining whether capabilities related to reactor coolant pressure boundary (RCPB) leakage detection should be included in the TS LCOs, are as follows:

a) *Criterion 1.* Installed instrumentation that is used to detect, and indicate in the control room, a significant abnormal degradation of the reactor coolant pressure boundary.

b) *Criterion 2.* A process variable, design feature, or operating restriction that is an initial condition of a design basis accident or transient analysis that either assumes the failure of or presents a challenge to the integrity of a fission product barrier.

Technical Specifications for PINGP, Units 1 and 2, require periodic verification that reactor coolant system leakage is within limits and that leakage detection instrumentation is operable. Specifically, existing TS Surveillance Requirement (SR) 3.4.14.1 requires operators verify by performance of RCS water inventory balance once every 24 hours after the plant reaches steady-state operation that RCS operational leakage is within limits, and existing TS LCO 3.4.16 requires operability of the containment sump pump runtime monitor and one radionuclide monitor when the plant is in operational Modes 1 (Power Operation) through 4 (Hot Shutdown).

3.0 TECHNICAL EVALUATION

3.1 Scope of the LBB Application

The licensee requested the NRC to approve the LBB methodology for the following RCS branch lines. Note that the piping diameters specified below represent the nominal pipe size, not the actual inside or outside diameter of the pipe.

(1) The 12-inch diameter safety injection (SI) lines (loops A and B) for both units. These lines are connected to the SI accumulators. The loop B line also serves as the residual heat removal (RHR) return line.

(2) The 8-inch diameter RHR lines (loops A and B) for both units. These lines serve as the RHR system suction lines. The LBB analysis also includes an evaluation of thermal stratification in the Units 1 and 2 RHR suction lines.

(3) The 6-inch diameter cold-leg SI lines (loops A and B) for both units. These lines provide flow from the high-pressure SI pumps.

(4) The 6-inch diameter reactor vessel SI lines (loops A and B) for both units.

(5) The 6-inch RCS drain down line on the hot-leg (loop A on Unit 1 and loop B on Unit 2).

(6) The 6-inch capped nozzle on the hot-leg (loop B on Unit 1 and loop A on Unit 2).

(7) The Unit 2 pressurizer surge line.

3.2 Screening Criteria for Degradation Mechanisms

Section 3.6.3.III of the SRP specifies that LBB piping should be evaluated to assess the potential effects of active degradation mechanisms such as fatigue, water hammer, corrosion, and its susceptibility to creep and cleavage failures to demonstrate that these mechanisms are not potential sources for pipe failure.

3.2.1 Fatigue

The SIA-401 and WCAP-15379 reports state that metal fatigue is not a significant issue for the candidate piping. The NRC staff notes that, based on pressurized water reactor (PWR) operating experience, the pressurizer surge line is susceptible to thermal stratification, which is a form of thermal-induced fatigue or failure. Section 3.6.3.III.10 of the SRP does not permit LBB to be applied to piping with a history of fatigue cracking. The NRC staff asked the licensee to address thermal stratification in the Unit 2 pressurizer surge line. By letter dated July 23, 2010, the licensee responded as follows:

> Based on known data, there has been no cracking in Westinghouse designed surge lines. There was one case in 1989 where the Trojan plant replaced a surge line nozzle for what was believed to have been a flaw. Subsequent examination of the nozzle did not identify any flaws. Therefore, there is no known history of surge line cracking.

The licensee further stated that a surge line thermal stratification analysis was performed for PINGP, Unit 2, to address the issues raised in NRC [Bulletin] 88-11, "Pressurizer Surge Line Thermal Stratification," which required licensees to evaluate pressurizer surge lines for fatigue due to the effects of thermal stratification. The licensee's analysis was documented in WCAP-12639 (Reference 1) and WCAP-12639 Supplement 1 (Reference 2) reports and was approved by the NRC (Reference 3). The licensee stated that thermal stratification is not a concern in the pressurizer surge line at PINGP, Unit 2, and that loads from thermal stratification were used in the associated LBB analysis. The NRC staff finds that the licensee has addressed the thermal stratification problems per NRC Bulletin 88-11 and the LBB analysis considered loads from the thermal stratification.

Based on the information provided by the licensee, the NRC staff finds that the licensee has demonstrated that fatigue is either: (1) not an active degradation mechanism, or (2) the licensee has addressed fatigue by analyses. Therefore, fatigue is not a significant concern in the candidate piping.

3.2.2 Water Hammer

The SIA-401 report stated that the portions of the piping evaluated for LBB are inboard of the first isolation valves for the SI and RHR piping. Thus, during normal operation, these lines experience reactor coolant pressure and temperature conditions, such that there is no potential for steam/water mixtures that might lead to water hammer. The portions of these systems that are adjacent to the reactor coolant piping are not in use during normal operation. The RHR system is not used except during low-pressure, low temperature cooldown conditions. The SI system is used only during a loss-of-coolant-accident (LOCA) condition. During normal plant operation, the portions of the system beyond the first isolation valve are expected to operate at low temperature conditions. Thus, there should never be any voiding or potential for steam bubble collapse, which could result in water hammer loads on the piping attached directly to the RCS considered in this evaluation. The licensee stated that, to date, there has been no experience related to water hammer events in either the RHR or SI systems at PINGP. As such, this phenomenon will have no impact on the LBB analysis for the affected portions of the SI and RHR at PINGP.

For the Unit 2 pressurizer surge line, the licensee stated in WCAP-15379 that there is a low potential for water hammer in the RCS and connecting surge line, since they are designed and operated to preclude the voiding condition in normally filled lines. The RCS and connecting surge line, including piping and components, are designed for normal, upset, emergency, and faulted condition transients. The design requirements are conservative relative to both the number of transients and their severity. Relief valve actuation and the associated hydraulic transients following valve opening are considered in the system design. Other valve and pump actuations are relatively slow transients with no significant effect on the system dynamic loads. To ensure dynamic system stability, reactor coolant parameters are stringently controlled. During normal operation, temperature is maintained within a narrow range by control rod position; pressure is controlled by pressurizer heaters and pressurizer spray, also within a narrow range for steady-state conditions. The flow characteristics of the system remain constant during a fuel cycle because the only governing parameters; namely, system resistance and the reactor coolant pump characteristics, are controlled in the design process. Additionally, Westinghouse has instrumented typical reactor coolant systems to verify the flow and vibration characteristics of the system and connecting surge line. Preoperational testing and operating experience have verified the Westinghouse approach. The operating transients of the RCS primary piping and connected surge line are such that no significant water hammer can occur.

The NRC staff finds that, based on the licensee's assessment, water hammer is not a significant concern in the candidate piping.

3.2.3 Stress Corrosion Cracking

Stress corrosion cracking (SCC) occurs when high tensile stresses, susceptible material, and a corrosive environment exist simultaneously. Since some residual stresses and some degree of material susceptibility exist in stainless steel piping, the licensee minimizes the potential for stress corrosion by selecting a material resistant to SCC and by preventing the occurrence of a corrosive environment. The licensee's material specifications consider compatibility with the system's operating environment (both internal and external) and other material in the system,

applicable American Society of Mechanical Engineers (ASME) Code rules, fracture toughness, welding, fabrication, and processing.

The elements of a water environment known to increase the susceptibility of austenitic stainless steel to stress corrosion are: oxygen, fluorides, chlorides, hydroxides, hydrogen peroxide, and reduced forms of sulfur. The licensee cleaned the internal and external pipe surfaces before commercial operation and has controlled water chemistry during plant operation to prevent the occurrence of a corrosive environment. During flushes and preoperational testing, water chemistry is controlled in accordance with written specifications. The licensee follows the acceptance criteria on chlorides, fluorides, conductivity, and pH level. During plant operation, the licensee monitors and maintains the reactor coolant water chemistry within specific limits. For example, the licensee controls charging flow chemistry and maintains hydrogen in the reactor coolant at specified concentrations to limit oxygen concentration in the RCS. Halogen concentrations are also controlled by maintaining concentrations of chlorides and fluorides within specified limits.

Primary water stress corrosion cracking (PWSCC) has occurred in Alloy 82/182 dissimilar metal butt welds in PWRs. Section 2.1 of WCAP-15379-P states that SCC in the RCS primary loop and connecting Class 1 lines is a low probability event. Because Alloy 82/182 welds are susceptible to PWSCC and do exist in the Unit 2 pressurizer surge line, the NRC staff asked the licensee to explain why SCC is considered a low probability event. By letter dated July 23, 2010, the licensee stated that WCAP-15379-P was prepared in the early part of 2000, which was before the industry concern related to PWSCC in the primary loop piping nozzles at Alloy 82/182 locations. Therefore, PWSCC was not specifically addressed in WCAP-15379-P.

The licensee further explained that the LBB analysis for the Unit 2 pressurizer surge line is included in WCAP-15379-P and SIA-402. The SIA-402 report addresses a subsequent configuration change to the Unit 2 pressurizer surge line involving the addition of a weld overlay to provide a PWSCC resistant barrier to the Alloy 82/182 dissimilar metal weld. The SIA-402 report is a supplement to WCAP-15379-P, and provides a thorough evaluation of PWSCC issues at the Alloy 82/182 dissimilar metal weld in the Unit 2 pressurizer surge line. The licensee stated that there have been no instances of fatigue cracking or PWSCC in the PINGP, Unit 2, pressurizer surge line.

By letter dated July 23, 2010, the licensee clarified that the Unit 1 pressurizer surge line has no Alloy 82/182 dissimilar metal welds and that Alloy 82/182 dissimilar metal welds do not exist in the candidate RCS branch piping in this LAR, except for the Unit 2 pressurizer surge line.

The NRC staff finds that the candidate RCS branch pipes have no Alloy 82/182 dissimilar metal welds, except Unit 2 pressurizer surge line. As for the Unit 2 pressurizer surge line, the licensee has mitigated the potential for PWSCC in the Alloy 82/182 dissimilar metal weld by a weld overlay.

Therefore, the NRC staff finds that the likelihood of PWSCC affecting the candidate RCS branch pipes is small.

3.2.4 Creep and Cleavage Failures

Creep is not a concern for the candidate RCS piping because the operating temperature of 600 to 650 degree Fahrenheit (°F) in PWRs is less than the temperature that would cause significant creep damage to the piping. Also, cleavage failure is not a concern because the operating temperatures are below the cleavage failure temperature. Stainless steel used for the candidate piping also minimizes the potential for cleavage failure.

3.3 Fracture Mechanics Analysis

In addition to the screening criteria above, SRP Section 3.6.3, also specifies the fracture mechanics analyses that must be performed for LBB applications. Section 3.4 below discusses the fracture mechanics analysis of the RCS branch piping and Section 3.5 discusses the analysis of the Unit 2 pressurizer surge line. The licensee's fracture mechanics analysis of the Unit 2 pressurizer surge line is different than the analysis of the RCS branch line piping because the Unit 2 surge line contains an overlaid Alloy 82/182 dissimilar metal weld that requires specific modeling considerations. The NRC staff notes that the circumferential, not the axial, through-wall flaw is controlling in the fracture mechanics analysis for the LBB application. The critical sizes for axial flaws are much longer than (i.e., not as conservative as) those for circumferential flaws because axial flaws are only affected by pressure stress. Therefore, the fracture mechanics analyses discussed herein focus on circumferential flaws only.

3.4 Fracture Mechanics Analysis of RCS Branch Piping

3.4.1 Piping Components

The SIA-401 report documents the fracture mechanics analysis for the RCS branch piping system Items 1 through 6, as listed in Section 3.1 above. Some of the 6-inch diameter candidate pipes are connected to non-candidate pipes and the segments that are part of the LBB application are described as follows. The licensee requested LBB for the pipes that are 6-inch or greater in diameter. Piping that is less than 6 inches in diameters is not part of the LBB application.

The 6-inch reactor vessel SI lines (Item 4 in Section 3.1 of this SE) are composed of 4-inch diameter lines from the reactor vessel nozzle connected to a shorter section of 6-inch diameter lines near the isolation valves. By letter dated July 23, 2010, the licensee stated that for Unit 1 loop A, the 4-inch diameter pipe segment of the SI line is approximately 106 inches in length and the 6-inch diameter segment is approximately 62 inches in length. For Unit 1 loop B, the 4-inch diameter pipe segment of the SI line is approximately 228 inches in length and the 6-inch diameter segment is 0 inches in length (i.e., a 4-inch by 6-inch reducer).

For Unit 2 loop A, the 4-inch diameter pipe segment of the SI line is approximately 120 inches in length and the 6-inch diameter pipe segment is approximately 11 inches in length. For Unit 2, loop B, the 4-inch diameter pipe segment of the SI line is approximately 221 inches in length and the 6-inch diameter pipe segment is approximately 12 inches in length.

The 6-inch drain down lines (Item 5 in Section 3.1 of this SE) consists of short sections of 6-inch diameter piping that reduce to 2-inch diameter lines at the isolation valves. The licensee stated

that the 2-inch diameter segment in the drain down line is actually a 3-inch diameter segment. The licensee identified that this is an inadvertent error in the original December 22, 2009, submittal. This error does not affect the LBB evaluation because the 3-inch line was not analyzed and was not part of the LBB application. For Unit 1, the 3-inch diameter portion of RCS drain down line is 29.5 inches in length and the 6-inch portion of drain down line is 4 inches in length. For Unit 2, the 3-inch diameter pipe segment of the RCS drain down line is 20.5 inches in length, and the 6-inch portion of the drain down line is 4 inches in length.

The NRC staff noted that if pipe whip restraints are not installed on the 3-inch diameter portion of the drain down line and 4-inch diameter portion of the SI line, and if pipe whip restraints on the 6-inch diameter portion of these two lines are removed as a result of the LBB license amendment approval, the 6-inch diameter portion of these lines will not be protected should the 3-inch or 4-inch lines fail in a double-ended guillotine break. By letter dated July 23, 2010, the licensee responded that there are no pipe whip restraints installed on the 4-inch diameter portion of the SI line or on the 3-inch diameter portion of the RCS drain down line. The licensee further explained that the 6-inch diameter portion of these lines is protected by existing pipe whip restraints. The licensee stated that the dynamic effects of pipe ruptures occurring on the 4-inch portions of these lines, for which LBB technology has not been applied, must still be considered. The restraint system must maintain its ability to protect safety-related SSCs from the effects of pipe whip and jet impingement due to the ruptures from the 3- and 4-inch diameter pipes.

The licensee also stated that it has no current plans to remove the whip restraints from the 6-inch SI lines. For any future plans to remove the existing pipe whip restraints, the licensee would need to demonstrate analytically that ruptures occurring on the 3-inch and 4-inch pipes would not result in a plastic hinge and pipe whip that could damage safety-related SSCs.

The NRC staff finds this is acceptable because, before removing whip restraints on the 6-inch pipes, the licensee must demonstrate by analysis that the ruptures of the 3-inch and 4-inch diameter lines in the RCS drain down system and SI system, respectively, will not result in damaging to the SSCs and the 6-inch diameter segment of the pipe systems.

3.4.2 Load Combinations for RCS Branch Piping

Section 3.6.3.III.11.C of the SRP specifies the application of pipe loads in deriving critical and leakage flaw sizes in the LBB evaluation. The licensee considered the piping loads (moments and stresses) due to pressure, dead weight, thermal expansion and safe shutdown earthquake (SSE) in the fracture mechanics analysis as shown in Section 4 of the SIA-401 report. The licensee also included the loadings from the power uprated conditions, which are discussed in Section 3.6 of this SE.

The NRC staff noted that the licensee multiplied the normal operating pressure by 1.01 to calculate the critical flaw size as shown in the SIA-401 report. By letter dated July 23, 2010, the licensee explained that the nominal RCS operating pressure is 2235 pounds per square inch – gauge (psig). However, in actual practice, operational fluctuations sometimes result in sustained RCS pressures as high as 2253 psig. In order to bound the anticipated range of pressures in service, a 1.01 multiplier was applied to the nominal pressure to account for these fluctuations. The licensee noted that the higher pressure is used for flaw calculations because it results in smaller, conservative flaw sizes, with a given leak rate, while the nominal pressure is used in the

leak rate calculation to yield lower, thus more conservative, leakage results. The NRC staff finds it is acceptable that the licensee used a conservative approach when applying the pressure multiplier.

The NRC staff finds that the licensee has followed the load combinations for the flaw size calculation in accordance with SRP Section 3.6.3. Therefore, the NRC staff finds the load combinations in the LBB evaluation to be acceptable.

3.4.3 Material Properties for RCS Branch Piping

Sections 3.6.3.III.11.A and 3.6.3.III.11.B of the SRP specify that plant-specific material specifications and material properties should be used in the LBB evaluation. In lieu of this specification, the licensee used material properties associated with the least favorable material and welding processes from industry-wide generic material sources to provide a conservative assessment of critical flaw sizes and leakage rates.

The material properties of interest for crack and leakage calculations are the modulus of elasticity, the yield stress, the ultimate stress, the Ramberg-Osgood parameters for describing the stress strain curve, the fracture toughness and power law coefficient for describing the material J-resistance (J-R) curve.

The SIA-401 report states that the material for all candidate pipes is A-376, Type 316 stainless steel. The piping was fabricated using the gas tungsten arc welding (GTAW) process for the weld root, and filled the remaining weld using the shielded metal arc welding (SMAW) process. The least favorable properties between the GTAW and SMAW weldments have been used in the LBB evaluation. The SMAW weldment, because of its low toughness and susceptibility to thermal aging, has the most conservative properties for the estimation of critical flaw sizes. Hence, the licensee has used the properties of SMAW in the LBB evaluation.

For the J-R curve properties, the licensee used the lower bound curve provided in NUREG-6428 (Reference 4) for thermally aged welds at 550 °F. The Ramberg-Osgood parameters were determined at 650 °F, as presented in Appendix A of the SIA-401 report, and the values at 607.4 °F (hot-leg temperature) were then interpolated from the values at 550 °F and 650 °F.

The NRC staff finds that the licensee has used the appropriate material properties in its LBB evaluations.

3.4.4 Critical and Leakage Crack Size Calculation for RCS Branch Piping

Section 3.6.3.III.11.C of the SRP specifies how the critical and leakage crack sizes should be calculated. SRP Section 3.6.3.III.11.C(ii) specifies that the pipe locations with the least favorable material properties should be used. SRP section 3.6.3.III.11.C(v) specifies that a crack stability analysis should be performed to demonstrate that the leakage crack size will not become unstable.

The licensee selected the least favorable locations in each of the pipe systems, derived the critical crack size at these locations, analyzed the leakage flaw sizes at those locations that would result in a 2 gpm leak, and evaluated the stability of these flaws under various faulted

conditions. The licensee performed a stability analysis to demonstrate that the postulated circumferential cracks are stable with a margin of at least two between the leakage flaw size and the critical flaw size.

The licensee calculated the critical flaw sizes using both the limit load (net section collapse) criterion methodology and J-integral/tearing modulus methodology. The more conservative results (the flaw sizes resulting in the smallest margin) of the two methods were chosen for the least favorable pipe locations.

SRP Section 3.6.3.III.11.C(v) states that:

> " . . . Demonstrate that the size of leaking cracks will not become unstable if 1.4 times the normal plus Safe Shutdown Earthquake loads are applied . . . . The 1.4 margin should be reduced to 1.0 if the deadweight, thermal expansion, pressure, SSE (inertial), and seismic anchor motion loads are combined based on individual absolute values . . ."

In calculating the critical crack size, the licensee applied a factor of 1.0 on the normal plus SSE stresses and a factor of $\sqrt{2}$ (1.4) on the normal plus SSE stresses, consistent with the guidance in SRP Section 3.6.3. SRP Section 3.6.3.III.11.C(iv), specifies that the leakage flaw size should be half of the critical crack size (i.e., a margin of 2) if a factor of 1.0 is applied on normal plus SSE stresses. For the case where the factor of $\sqrt{2}$ is applied, the critical crack size is the leakage crack size. The licensee determined that the normal plus SSE stresses method, based on a factor of 1.0, resulted in the smaller and, thus, a conservative critical crack size.

After the critical crack size was derived, the licensee reduced the critical crack size by half to obtain the leakage flaw size. This would satisfy the margin of 2 on crack size, as specified in SRP, Section 3.6.3. The licensee then used the derived leakage flaw size to calculate the leak rate to determine whether the margin of 10 on leak rate is satisfied in accordance with SRP Section 3.6.3. The leakage and critical flaw sizes for the RCS branch piping are listed in Sections 4 and 5 of the SIA-401 report.

The NRC staff finds that the licensee used the appropriate method to obtain the conservative critical and leakage crack sizes. The NRC staff finds that a margin of at least 2 has been achieved between the critical crack size and the leakage crack size for the RCS branch piping. The NRC staff finds that the licensee has demonstrated that postulated cracks at the least favorable pipe locations will be stable and will not propagate uncontrollably under the applied loads.

3.4.5 Leakage Rate Calculation for RCS Branch Piping

Section 3.6.3.III.11.C(iii) of the SRP specifies that the leakage crack size should be sufficiently large so that the estimated leak rate during normal operation would be 10 times greater than the minimum RCS leakage detection system capability, which is 0.2 gpm. The same SRP section further states that the normal operating loads (i.e., deadweight, thermal expansion, and pressure) are to be combined based on the algebraic sum of individual values and applied to the leakage flaw size. Section 5 of the SIA-401 report (ADAMS Accession No. ML100200131) provides the leak rate results.

The licensee used the Electric Power Research Institute (EPRI) PICEP computer code to perform leak rate calculations as discussed in the SIA-401 report. The licensee used the procedure described in NUREG/CR-6300 (Reference 5) to model flow path, including surface roughness, flow path length, and number of flow path turns. The licensee performed a sensitivity study to compare leakage calculated using the fatigue morphology parameters and PWSCC morphology parameters. The licensee stated that PWSCC is not considered to be credible in the RCS branch piping (except the Unit 2 pressurizer surge line) and, therefore, considered mainly the fatigue crack morphology in the leakage calculations for the RCS branch line pipes.

The licensee also performed a sensitivity study on the impact of the restraint of pressure-induced bending in a piping system on the LBB analysis results. This was shown to be especially important for small diameter piping, such as that being considered for PINGP. With a crack in an unrestrained pipe, there is localized bending of the pipe concentrated in the crack region. This results in a "kink angle", which can be described as a change in direction of the straight pipe due to the presence of the crack. However, all the piping systems considered in this LBB evaluation are restrained to varying degrees. The opening of the crack and the resulting localized kink angle is resisted by the piping restraints, resulting in a bending moment at the crack location that is in the opposite direction of the kink angle. The licensee stated that the presence of the restraint in a flawed piping has two effects: (1) in a restrained piping system, this induced bending can be restrained, resulting in an increased load capacity for the flawed piping (i.e., the critical flaw size increases), and (2) the restraint of the bending moment decreases the crack opening displacement and, hence, reduces the leakage that would have otherwise been calculated.

Based on the licensee's sensitivity study, the piping restraint effects have no significant impact on the predicted leakage rates for the 6-inch SI and drain down lines. At the least favorable location, piping restraint produces approximately 13 percent reduction of the leak rate on the 8-inch RHR line. The NRC staff finds it acceptable that the licensee adequately evaluated the effect of pipe restraint and that the piping restraint does not significantly affect the predicted leakage rate.

The NRC staff finds that the licensee has performed an appropriate leak rate calculation to demonstrate that there is a margin of 10 between the leak rate from the leakage crack size and the RCS leakage detection system capability of 0.2 gpm.

3.4.6 Fatigue Crack Growth Analysis of RCS Branch Piping

In accordance with NUREG-1061, Volume 3, the licensee calculated the growth of postulated surface cracks due to fatigue to demonstrate that fatigue growth is insignificant for the plant life, when initial flaw sizes meeting ASME Code, Section XI IWB-3514, acceptance standards are postulated. The fatigue crack growth analysis is performed for the locations with the maximum stresses. The licensee used bounding stresses from PINGP Units 1 and 2 and Kewaunee, as discussed in Section 6.0 of the SIA-401 report.

The postulated initial flaw size is linearly interpolated based on the allowable flaw sizes for various thicknesses from ASME Code, Section XI, Table IWB-3514-2, Inservice Examination,

surface crack with an aspect ratio a/l of 0.15 (a = crack depth and l = crack length). The initial crack depth was assumed to be approximately 11-percent of the pipe wall thickness.

Because the RCS branch piping lines were designed to the requirements of American National Standards Institute B31.1, no specific line-unique transients exist in the design basis. The licensee used transients consisting of those for the reactor pressure vessel (specified in the Plant Technical Specification) and additional transients specific to the operation of these systems, as discussed in Section 6.1 of the SIA-401 report.

Section 6 of the SIA-401 report states that:

> " . . . although there was a safety injection transient in Unit 1 due to [steam generator] tube rupture in 1979, there have been no inadvertent safety injections since. This transient is therefore also considered unlikely and was not evaluated . . . "

The NRC staff noted that an SI event did occur in 1979. Therefore, the SI transient appears to be a likely event and should be considered in the fatigue crack growth calculation. The NRC staff asked the licensee to justify why the inadvertent SI should not be considered in the evaluation, and discuss the actions/measures that preclude the potential for having an inadvertent SI. By letter dated July 23, 2010, the licensee responded as follows:

> The stress intensity factor range (ΔK) associated with the inadvertent safety injection due to the tube rupture is estimated to be 0.428 ksi$\sqrt{\text{in}}$. Since plant startup, only one such event has taken place. If it is conservatively estimated that 10 cycles of this event will occur for the balance of plant life, then the calculated crack growth for these 10 cycles is 2.46×10^{-8} inches, which is small compared to the final crack size of 0.0839 inches in Table 6-13 [of the SIA-401 report]. Therefore, not including this transient in the fatigue crack growth evaluation does not change the conclusions of the analysis.
>
> Many of the potential causes of inadvertent safety injection events are related to breaks in steam lines or a steam generator tube rupture, which was the cause of the inadvertent safety injection event at PINGP in 1979. Periodic inspections of steam generator tubes and plugging of tubes when necessary are performed to minimize the likelihood of such events. These actions also minimize inadvertent safety injections and . . . there have been no such events in over 30 years of operation at PINGP.

The NRC staff finds that it is acceptable that inadvertent SI events are not included in the load combinations because of the low probability of such events and their low impact to the subject piping systems.

The NRC staff asked the licensee to explain why the fatigue crack growth calculation did not consider local piping system transients for the 6-inch diameter drain down line and the 6-inch diameter hot leg nozzles. By letter dated July 23, 2010, the licensee responded that:

> All local piping system transients are described in Table 6-2 [of the SIA-401 report]. These transients do not affect the draindown line or the hot leg nozzles. These two lines experience only the transients described in Table 6-1 [of the SIA-401 report], and no additional local transients are considered for these two lines. Only hot leg transients described in Table 6-3 [of the SIA-401 report] are applied to these two lines because they are attached to the hot leg.

The licensee further stated that local piping system transients were applied to other pipes. For example, the "High Head Safety Injection" transient is applied to the 6-inch diameter cold-leg SI lines, the "Residual Heat Removal (RHR) operation at Cooldown" transient is applied to the 12-inch diameter SI accumulator lines, the "Refueling Floodup" transient is applied to the 12-inch diameter SI accumulator lines, and the "RHR initiation" transient is applied to the 8-inch diameter RHR suction lines.

The licensee further stated that the local piping system transients affect only certain piping lines. As an example, transients in Table 6-2 of the SIA-401 report affect only certain piping lines. However, design basis transients/non-local transients (such as the transients shown in Table 6-1, of the SIA-401 report) affect the entire piping system. The thermal transients for the hot leg (Table 6-3 of the SIA-401 report) are used as the thermal transients for the drain down lines because the drain-down lines are attached to the hot-leg.

The NRC staff asked the licensee to explain why stresses due to the seismic event were not discussed in the crack growth evaluation in Section 6-2 of the SIA-401 report. By letter dated July 23, 2010, the licensee responded that Operating Basis Earthquake (OBE) stresses should have been mentioned explicitly in Section 6-2 of the SIA-401 report because the OBE stress was included in the fatigue crack growth calculation. The stress due to OBE is included in the stress range calculation in combination with other plant conditions.

The licensee used the fatigue crack growth law for the stainless steel piping in accordance with the recommendation of the ASME Code, Section XI, Task Group for Piping Flaw Evaluation (Reference 6). The stress intensity factor, K, in the fatigue crack growth law corresponds to the point of the maximum depth of a semi-elliptical crack that is calculated using the fracture mechanics solutions presented in Reference 7. The stress intensity factors are determined for a conservative aspect ratio (a/l) of 0.1.

The licensee's results show that, for the 6-inch cold-leg SI and drain down piping, crack growth is very minimal. However, for the 12-inch, Schedule 160, SI accumulator line, 38 heatup/ cooldowns at the worst location would need to occur before the allowable flaw size would be reached. Similarly, for the 8-inch Schedule 140 RHR Suction line, 123 heatup/cooldowns at the most critical location would need to occur to reach the allowable flaw size. As a comparison, for the last 10 years, PINGP has experienced 13 heatup/cooldown cycles, which is significantly less than the minimum allowable number of 38 calculated at the most critical locations. The licensee stated that, given that the piping is inspected in accordance with the ASME, Section XI, requirements in each 10-year inservice interval, the potential for crack growth can be managed by the current (ISI) inspection program at PINGP.

The NRC staff finds that the licensee has demonstrated that fatigue crack growth is insignificant for the 6-inch RCS branch lines. For the 8-inch and 12-inch diameter RCS branch lines, the

NRC staff notes that the final fatigue crack sizes are not insignificant. However, the licensee has used conservative heatup/cooldown transients in its analysis. Therefore, the NRC staff finds that the monitoring approach of the ASME Code, Section XI, ISI program every 10 years for the 8-inch and 12-inch diameter candidate pipes is acceptable to provide reasonable assurance of the structural integrity of the subject pipes.

3.5 Fracture Mechanics Analysis for Unit 2 Pressurizer Surge Line

3.5.1 Background

In 1992, the NRC approved the LBB application for the Unit 1 pressurizer surge line. In March 2000, the licensee prepared the LBB analysis for the Unit 2 pressurizer surge line, as documented in the Westinghouse report, WCAP-15379-P. However, at the time, the licensee did not submit WCAP-15379 for NRC review and approval for the LBB application for the Unit 2 pressurizer surge line.

In 2008, the licensee installed a weld overlay (weld No. W-18) to mitigate the possibility of PWSCC in the nickel-based Alloy 82/182 dissimilar metal weld (weld No. W-17) located at the pressurizer nozzle-to-safe-end joint of the Unit 2 surge line. Subsequently, the licensee performed an updated LBB analysis to consider the impact of the weld overlay on the Alloy 82/182 weld in the Unit 2 surge line as shown in the SIA-402 report. The limiting location, as discussed in WCAP-15379-P, is Node 1320, which is the pressurizer nozzle-to-piping weld, made of Alloy 82/182 filler material. The SIA-402 report also analyzed Node 1320.

3.5.2 Weld Overlay

Before installing the weld overlay in 2008, the licensee ultrasonically inspected the Alloy 82/182 weld in the Unit 2 pressurizer surge line using a Performance Demonstration Initiative qualified technique. The licensee did not find any relevant indications in the Alloy 82/182 weld. Following the overlay installation, the licensee performed ultrasonic testing of the overlaid weld in accordance with ASME, Section XI, Appendix VIII, Supplement 11, as modified in NRC-approved Relief Request 2-RR-4-8, Revision 1. No relevant indications were identified. The surge line nozzle with the overlaid weld was also examined during the May 2010, Unit 2 refueling outage. No indications were identified during that examination.

The license renewal period of extended operation for Unit 2 expires in 2034. The licensee determined that, within the remaining service life, an initial postulated 360 degree circumferential 75 percent through-wall flaw in the original weld will not exceed ASME Section XI acceptance criteria for the overlaid configuration. As additional assurance, the licensee will ultrasonically re-inspect the overlaid Alloy 82/182 weld in the Unit 2 pressurizer surge line every ten years in accordance with the guidance of EPRI report, MRP-139 (Reference 8), and requirements of ASME Code Case N-770 "Alternative Examination Requirements and Acceptance Standards for Class 1 PWR Piping and Vessel Nozzle Butt Welds Fabricated with UNS N06082 or UNS W86182 Weld Filler Material." The NRC staff notes that Code Case N-770-1 with conditions has been incorporated by reference in 10 CFR 50.55a(g)(6)(ii)(F). Therefore, the licensee is required to follow Code Case N-770-1. The re-inspection will confirm the condition of the overlaid weld every 10 years. If no indications are found, the clock on the postulated crack growth will be reset to zero and the qualified life of the weld will be renewed. This re-inspection

will occur through the remainder of current license period and through the license renewal period of extended operation.

3.5.3 Load Combinations for Unit 2 Pressurizer Surge Line

The updated LBB analysis in the SIA-402 report for the Unit 2 pressurizer surge line used the original load combinations as described in WCAP-15379. In addition to the loads due to pressure, dead weight, thermal expansion and SSE, the surge line experiences loads due to various transients that could be significant in terms of thermal loading. Section 4.4 of WCAP-15379 presented three different operating conditions (Cases A, B, and C) to determine the leakage flaw size. These cases include various combinations of thermal expansion, thermal stratification, and heatup/cooldown loads. WCAP-15379 also presented various faulted conditions (Cases D, E, F and G) to determine the critical flaw size. These faulted cases include various combinations of SSE, thermal expansion, thermal stratification, and heatup/cooldown loads. The NRC staff noted that some of the load combinations were not included in the LBB analysis. By letter dated July 23, 2010, the licensee responded that those load combinations that are not relevant to the operations or have a very low probably of occurrence are not considered in the LBB analysis.

The licensee further stated that the completeness of the load combinations selected for evaluation in the LBB analysis can also be verified by comparing the results of the leakage flaw sizes and critical flaw sizes. The licensee was able to demonstrate that the ratio of the worst case leakage flaw length to the worst case critical flaw length exceeds the margin of 2.

The licensee stated that the load combinations evaluated address a credible range of conditions under which a postulated RCS leak would be detected, and the range of conditions that could be encountered until the leak could be repaired. The load combinations evaluated in the analysis conservatively bound other combinations.

The NRC staff asked the licensee to justify why thermal stratification loads were not combined with SSE loads as shown in Table 4-2 of SIA-402 report. By letter dated July 23, 2010, the licensee clarified that the duration of the transients (e.g., heatup) that cause large stratification loads is relatively short and the likelihood of an SSE during those transients is extremely low. Therefore, it is reasonable that thermal stratification loads are not added to SSE loads. The licensee stated that loads are used as total moments. That is, the square root of the sum of squares (SRSS) of each of the moments from the three directions (x, y, z). The SRSS moments due to thermal stratification are approximately 19 percent of the SSE moments. Therefore, the licensee concluded that it is reasonable to use the larger of the loads from either SSE or stratification in the LBB evaluation.

By letter dated August 20, 2010, the licensee stated that the ASME Code does not specify loads or load combinations for design of Class 1 components. Rather, the loads and load combinations are specified in the Design Specification for the component. The licensee further explained that the PINGP, Unit 2, pressurizer surge line was designed in accordance with USA Standard (USAS) B31.1, "Code for Pressure Piping - Power Piping," 1967, which also does not specify loads or load combinations for upset, emergency, or faulted conditions. For the PINGP Unit 2 pressurizer surge line, the loads and load combinations are described in Updated Safety Analysis Report (USAR) Table 12.2-13, "Loading Combinations and Stress Limits: Pressure

Piping in Accordance with USAS B31.1." Table 12.2-13, and the discussion in USAR Section 12.2.1, "Design Basis," do not identify thermal stratification as a design basis load for the pressurizer surge line. Therefore, the licensee concluded that the thermal stratification has not been combined with other loads for the design basis piping analyses. The NRC staff concludes, based on judgement, that the probability of thermal stratification occurring during an SSE is low. Therefore, it is acceptable that the thermal stratification loads are not combined with the SSE loads.

The NRC staff noted that the insurge and outsurge in the pressurizer would create significant temperature differences in the surge line, which would cause thermal stresses. The staff asked the licensee if the insurge and outsurge conditions were considered. By letter dated July 23, 2010, the licensee stated that the stratification stages represent initial/final conditions bounding insurge and outsurge transients and, therefore, loads from insurge and outsurge were considered in the LBB evaluation.

The NRC staff questioned whether the weight of the weld overlay is included in the applied loads in the Unit 2 pressurizer surge line LBB evaluation. By letter dated July 23, 2010, the licensee responded that:

> The Pressurizer Surge Line and Surge Nozzle were evaluated for the effect of the increased weight and stiffness due to the weld overlay, as part of the overlay design process. These effects were determined to be negligible on the piping and component loadings. The LBB evaluation subsequently used the design loads for the surge nozzle overlay for the dead weight and seismic inputs, which bound the actual loads from the pipe stress analysis by a large margin.

The NRC staff finds that the licensee has considered the mass of the weld overlay in the LBB evaluation and, therefore, is acceptable.

The NRC staff finds that the licensee has considered appropriate load combinations in the LBB analysis. Therefore, the load combinations used in the fracture mechanics analysis for the Unit 2 pressurizer surge line are acceptable.

3.5.4 Critical and Leakage Crack Size Calculation for Unit 2 Pressurizer Surge Line

As discussed in the SIA-402 report, the licensee used the limit load methodology to determine the critical flaw size at the overlaid Alloy 82/182 dissimilar metal weld (Node 1320) in accordance with the guidance in SRP Section 3.6.3, except that it considers the combination of geometry and different material properties for the Alloy 52M weld overlay and the original Alloy 82/182 dissimilar metal weld. The critical flaw size was calculated using the lower bound base metal tensile properties. As for the crack geometry, the licensee assumed the crack length was the same for the weld overlay and the Alloy 82/182 dissimilar metal weld.

For the limit load analysis, SRP, Section 3.6.3.III.11.C(viii), specifies the "Z factor" for shielded metal arc welds (SMAW) and submerged arc welds (SAW) for consideration of crack locations within low toughness materials. The purpose of the Z factor application is to increase the applied pipe loads to compensate for the slightly lower material toughness properties of the

SMAW and SAW welds. The welds at the governing location are fabricated with GTAW and SMAW. Therefore, the licensee applied the Z factor correction in the limit load calculation.

The licensee calculated that the critical flaw size for the dissimilar metal weld ranges from 17.75 inches for the minimum overlay thickness to 21.83 inches for the maximum overlay thickness.

After the critical crack size was derived, the licensee reduced the critical crack size by half to obtain the leakage flaw size to satisfy the margin of 2 on crack size, as specified in SRP, Section 3.6.3. The licensee then used the given leakage flaw size to calculate the leak rate to determine whether the margin of 10 on leak rate is satisfied for the Unit 2 surge line.

3.5.5 Leakage Rate Calculation for Unit 2 Pressurizer Surge line

Both the SIA-402 and WCAP-15379 reports discuss leak rate calculations. However, the leak rate calculation performed in the SIA-402 report is different from the leak rate calculation performed in the WCAP-15379 report because the SIA-402 report analyzed the overlaid Alloy 82/182 weld whereas the WCAP-15379 analyzed the original Alloy 82/182 weld. The SIA-402 report provides the updated leak rate calculation of the overlaid Alloy 82/182 weld and, therefore, will be discussed here.

The SIA-402 report used EPRI's PICEP computer program to calculate the leak rate and assumed the PWSCC morphology in the original Alloy 82/182 weld and the fatigue crack morphology in the weld overlay. The leak rate parameters for PWSCC morphology such as surface roughness, effective flow path length and number of flow path turns were based on NUREG/CR-6300 (Reference 5). The leak rate parameters for the fatigue crack morphology were based on the parameters in Reference 9.

Also, because the overlaid dissimilar metal weld contains material properties of Alloy 52M and Alloy 82/182, the licensee used composite material properties based on the relative thickness of the overlay and the original weld. The composite material properties involved yield strength, modulus of elasticity, and Ramberg-Osgood parameters.

The licensee calculated leakage crack sizes based on the given leak rate of 2 gpm (10 times the RCS leakage detection system capability). The licensee also calculated leak rate based on the given leakage crack sizes (half of the critical crack sizes). The results showed that with the application of the weld overlay, the SRP, Section 3.6.3, margins of 2 on the crack size and of 10 on the leak rate are maintained for the Unit 2 pressurizer surge line.

The NRC staff finds that the leakage calculation for Unit 2 pressurizer surge line is acceptable because the licensee has used an appropriate method and input parameters.

3.5.6 Fatigue Crack Growth Analysis of the Unit 2 Pressurizer Surge Line

The WCAP-15379 discusses the fatigue crack growth analysis for the Unit 2 pressurizer surge line. The licensee did not perform a plant-specific fatigue crack growth calculation for Unit 2 pressurizer surge line. Instead, it used the results of the fatigue crack growth calculation for the Unit 1 surge line to apply to the fatigue crack growth calculation for the Unit 2 surge line. By

letter dated July 23, 2010, the licensee explained that, based on Table 4-4 in WCAP-12877 (Reference 10) for the Unit 1 surge line LBB evaluation and Table 4-4 in WCAP-15379, the surge line loads at the highest stressed location in Unit 1 (Node 1240) bound the applied loads at the highest stressed location in Unit 2 (Node 1320). The licensee stated that the Unit 2 critical location was Node 1320 based on the highest faulted stress along the entire surge line. The surge line transients and geometry are comparable between the two units.

The licensee further explained that the piping stresses at Unit 1 Node 1240 in Table 4-4 of WCAP-12877 are higher than those of Unit 2 Node 1320 in WCAP-15379. Because Node 1320 is the governing LBB location for the entire Unit 2 surge line and Node 1240 of Unit 1 surge line envelops Node 1320, the Unit 1 fatigue crack growth results for Node 1240 will bound any fatigue crack growth results on Unit 2 Node 1320. The results show that the fatigue crack growth for both Units 1 and 2 surge lines is insignificant.

The NRC staff reviewed the licensee's fatigue analysis, and concludes that the fatigue crack growth for the Unit 2 surge line is bounded by Unit 1 surge line. The fatigue crack growth for the Unit 1 surge line demonstrated that fatigue will not affect the structural integrity of the pipe significantly. Because the Unit 1 fatigue crack growth bounds the Unit 2 fatigue crack growth and the Unit 1 fatigue crack growth is insignificant, the NRC staff finds that the potential fatigue crack growth will not significantly affect the structural integrity of Unit 2 pressurizer surge line.

3.6 Measurement Uncertainty Recapture (MUR) Power Uprate and License Renewal

The SIA-401 and SIA-402 reports have considered the MUR power uprate conditions for RHR thermal stratification. The NRC staff reviewed the MUR power uprate operating conditions and concludes that the discussion on the RHR thermal stratification in both SIA reports is acceptable. However, the staff asked the licensee to explain why some of the nodes reported in the subject LBB evaluation do not have updated loading data due to the uprate conditions and why there is no stress analysis performed at the uprate conditions on the subject piping. By letter dated July 23, 2010, the licensee stated that the MUR power uprate itself had very little effect on the normal and upset portions of the pipe stress analysis for the RCS branch lines because it resulted in only a 0.5 °F increase in the RCS hot-leg temperature, and a 0.5 °F decrease in the cold-leg temperature, which would have resulted in insignificant changes to the thermal stresses in the branch piping. However, the licensee reconciled several design discrepancies, including the different temperatures used in the original piping and component stress analyses as compared to the actual plant operating T-hot and T-cold values.

The licensee stated that the branch piping analyses often had not considered anchor displacements at the RCS nozzles due to LOCA loads. In the reconciliation effort, the licensee re-qualified the RCS branch line piping and nozzles to consider thermal stresses representing actual temperatures under MUR conditions and to include in the anchor movements in the faulted case of the SSE plus LOCA load combination. However, the branch lines themselves were not subject to complete dynamic reanalysis. Rather, for the highest stressed location for each branch line, the thermal stresses were extracted and then scaled to adjust for the uprate temperature conditions compared to the as-analyzed conditions.

The licensee also extracted the anchor movement stresses from the analysis of record and scaled to adjust for the revised total SSE plus LOCA anchor movements. The licensee

combined the revised thermal and anchor movement stresses with the other stresses in the original stress analysis and compared them to the allowable stress in order to check the qualification of each line. Because this method was used, and only the bounding highest stress location in a given pipe run was checked for qualification, the uprate work did not develop new stress results for every node on a given RCS branch line. However, new stresses were calculated for each RCS branch nozzle. The NRC staff finds that the licensee's explanation of the power uprate loading data is acceptable.

The licensee stated that the LBB evaluation for MUR power uprate was not performed specifically for the Unit 2 surge line because LBB was not approved for Unit 2 at the time the analysis was performed in 2000. For the current LBB evaluation, the licensee determined that the MUR uprate conditions have an insignificant impact on the pressurizer surge line. The licensee further clarified that the loads used in the LBB analysis are applicable for 60 years to include the period of extended operation.

The NRC staff finds that the licensee has appropriately considered the impact of the MUR power uprate conditions on the load combinations in the LBB analysis and has adequately resolved the issue.

3.7 RCS Leakage Detection

3.7.1 RCS Leakage Detection System Capability

As determined by the fracture mechanics evaluation, the postulated leakage flaw in the Unit 2 Loop B 8-inch Residual Heat Removal (RHR) line would produce the lowest leakage rate of 2.12 gpm, which would be limiting with respect to detection. Applying a margin of a factor of 10 for detection capability consistent with SRP Section 3.6.3 guidelines results in a necessary capability to detect an RCS unidentified leakage rate of <0.21 gpm to satisfy the LBB guidelines.

In its initial license amendment request dated December 22, 2009, the licensee described that PINGP has a diverse containment leakage detection capability utilizing up to 12 different methods of detecting leakage and the most sensitive of those methods had a minimum detectable leakage of as low as 0.1 gpm. However, the licensee did not definitively identify the detectors conforming to the guidance of SRP Section 3.6.3. In Enclosure 1 to the letter dated October 8, 2010, the licensee stated that the RCS inventory balance and the R-11 particulate radiation monitor were capable of detecting a 0.2 gpm leak in the RCPB.

The NRC staff also requested additional information regarding the leakage detection system conformance with the guidance of RG 1.45. In Enclosure 1 to the letter dated October 8, 2010, the licensee stated that the PINGP RCS leakage detection system licensing basis was consistent with the guidelines of Regulatory Guide (RG) 1.45 with respect to detecting a 1 gpm leak within 1 hour, but the PINGP RCS leak detection instrumentation licensing basis was not otherwise consistent with RG 1.45 guidance. The licensee justified this condition by stating:

> The design and licensing of PINGP preceded the publication of the Standard Review Plan (SRP) and RG 1.45 Revision 1. Therefore, the leakage detection systems are not required to satisfy the SRP criteria in Section 3.6.3.III.4.

However, the NRC staff concluded that the application of the review criteria of SRP Section 3.6.3 to the PINGP leak detection system capability was appropriate for the proposed expansion of LBB to the RCS connected piping.

3.7.1.1 Reactor Containment Particulate Radiation Monitor

In Enclosure 1 to the letter dated October 8, 2010, the licensee provided a description of newly installed beta scintillation containment particulate monitors, 1R-11 (Unit 1, installed in July 2010) and 2R-11 (Unit 2, installed in August 2010), which replaced the original containment particulate radiation monitors. The licensee stated that these PINGP beta detectors meet the 1 E-9 pCi/cc sensitivity described in the bases for PINGP Technical Specification 3.4.16, "RCS Leakage Detection Instrumentation." At this sensitivity, the R-11 particulate radiation monitor would respond to a 1 gpm leak at the original assumed RCS activity within 1 hour, consistent with RG 1.45 guidance. However, the licensee stated that the predicted response times for these detectors have increased in the past 30 years due to reduced RCS circulating activity levels and differences in the analysis methodologies. Based on this condition, the licensee reported in Enclosure 1 to the letter dated October 8, 2010, that the R-11 particulate radiation monitors had been classified as operable but non-conforming. The licensee stated that the condition had been entered into the PINGP corrective action program for resolution.

The NRC staff was concerned about the sensitivity of the replacement detectors to the low level of leakage necessary to satisfy the LBB guidance contained in SRP Section 3.6.3. The licensee responded to an additional request for information by letter dated January 14, 2011. In Enclosure 1 to this letter, the licensee described that the non-conforming condition of the new R-11 monitors had been resolved through performance of a more detailed calculation of the response time capabilities of the containment particulate monitors. The licensee described that the new calculation accounted for the additional activity contributed by the daughter products of noble gas decay, which were not previously included, while continuing to assume conservatively low circulating activity levels consistent with current normal plant operations. The licensee determined through these new calculations that the R-11 monitors monitoring each Unit's containment atmosphere remained capable of detecting a 1 gpm RCS leak within 1 hour at the lower circulating RCS activity levels currently present. In addition, the licensee determined that the R-11 monitors would be capable of detecting a 0.2 gpm leak within approximately 4 hours.

The NRC staff requested clarifying information regarding the modeling of the particulate daughters resulting from noble gas decay in the licensee's detector response time calculation. In the clarifying response provided by letter dated February 23, 2011, the licensee explained that daughter product activity was calculated based on the following assumptions:

- The accumulation of the parent noble gas is modeled using equations described in ISA 67.03-1982, "Standard for Light Water Reactor Coolant Pressure Boundary Leak Detection."
- The production and depletion of daughter products is modeled to reflect their radioactive decay properties.
- The behavior of particulate daughters is modeled using removal coefficients in NUREG/CR-6189, "A Simplified Model of Aerosol Removal by Natural Processes in Reactor Containments."

The licensee discussed additional assumptions regarding the sources of containment activity. The licensee explained that the activity released from a postulated coolant leak was based on radiochemical analysis of PINGP reactor coolant, with the particulate activity based on the average degassed activity during a recent period of operation with no known fuel leaks and the noble gas activity based on the lower bound of gaseous activity over a broad range of recent power operation data.

The NRC staff requested information regarding benchmarking of the containment particulate radiation monitor to better understand its performance. In the clarification provided by the letter dated February 23, 2011, the licensee stated that the calculated response time of the newly installed R-11 instrumentation had not been tested or benchmarked to actual plant leakage events because an active leak of sufficient magnitude and duration has not been experienced. However, the licensee stated that the new detectors were calibrated to several sources including a Strontium/Yttrium-90 source that emits two Beta particles at energies significantly lower than the Beta particles emitted by the noble gas daughter products of interest (i.e., Rubidium-88 and Cesium-138). The licensee stated that the nominal detector efficiency (i.e., ratio of detector counts to source activity) used in calculating the overall detector response to noble gas daughter products was conservative because it was based on the lower energy Beta particles provided by the calibration sources. In Enclosure 1 to the letter dated October 8, 2010, the licensee described operating experience related to detection of very small RCS leaks. The licensee stated that the original containment particulate radiation monitor [R-11] and the RCS inventory balance provide the first indication of very small leaks based on the following historical operating experience:

> On January 24, 1998, the PINGP Unit 1 was taken off-line following the detection of a leak, later found to be through-wall, on the G-9 part-length Control Rod Drive Mechanism (CRDM) housing. Detection was initially by the R-11 monitor, and confirmed by visual inspection during a containment entry. The unidentified leakage via inventory balance on the day the leak was detected was 0.19 gpm, and increased to 0.256 gpm the following day prior to the forced shutdown. On August 5, 1994, the PINGP Unit 2 was taken off-line to repair a CRDM canopy seal weld leak. The leak was identified by the R-11 monitor. The average unidentified leak rate from inventory balance in the week prior to the forced shutdown was 0.196 gpm.

In the Enclosure to a letter dated April 6, 2011, the licensee provided more detailed information using this operating experience in support of the R-11 particulate radiation monitor performance. This information included the content of telephone discussions between the NRC staff and licensee representatives held on March 14 and 28, 2011, which clarified the bases for assumed quantities of noble gas daughter products and their transport to the detector. The licensee referenced industry documents indicating noble gas daughters would be present as the dominant particulate contributors to the containment atmosphere activity from RCS leakage. The licensee also provided containment activity concentration data collected through grab samples of the containment atmosphere during the above events that demonstrated noble gas daughters were the dominant particulate contributors. Changes in the activity concentration of the noble gas constituents over the course of the events correlated with changes in the R-11 indicated count rate, providing support for the assumption that the noble gas daughters effectively transport to the detector. Furthermore, the licensee stated that the new R-11

sensitivity to source activity is at least double that of the previous R-11 instruments installed during these events and the new R-11 instruments use a much lower flow rate through the sample tubing that would reduce particulate losses from impingement in the sample line.

The final area of particulate radiation monitor performance the NRC staff questioned involved the ability of operators to interpret R-11 instrument count rate indications as a potential indication of RCS leakage. In the Enclosure to the letter dated February 23, 2011, the licensee stated that the ability of the operators to detect RCS leakage using the R-11 monitor was based on the detection definition in industry standard ISA 67.03-1982, which specified that the "minimum detectable concentration" of a radioactive particulate aerosol is that which generates an increase above the background count rate greater than 2.56 times the standard deviation of the background count rate. The licensee indicated that alarms would not aid in the detection of low levels of RCS leakage because the alarm point established for the R-11 containment particulate monitor was a high radiation alarm based on the Emergency Action Levels in the PINGP Emergency Plan and was not correlated to any specific RCS leakage rate. Based on the detection criterion and the frequency of operator monitoring of the instrument, the licensee estimated that a 0.2 gpm RCS leak would be detected within 24 hours.

The NRC staff remained concerned that the leakage detection criterion was relative to the background radiation level and no alarm would provide indication of a specific leakage level. Under these conditions, the staff concluded that slowly increasing leakage could be masked by the comparison of current R-11 count rate with the average count rate from an earlier time. The licensee addressed these concerns in the Enclosure to the letter dated August 9, 2011.

The licensee described changes to the monitoring of the R-11 indications. To improve R-11 instrument monitoring capability, the licensee committed to provide indications and alarms on the plant Emergency Response Computer System (ERCS) that will alert plant operators to potential RCS leakage based on containment particulate radiation monitor indications. These indications and alarms will be based on changes in mean count rates calculated over a ten minute period to smooth data variability. The licensee explained that the ERCS will continuously calculate rate-of-change values for mean count rate values established 1 hour apart and 4 hours apart. The 1 hour and 4 hour rate-of-change values would be compared against licensee-established criteria indicative of a 1 gpm and 0.2 gpm leak, respectively. The licensee stated that the criteria would be established using the same methodology used to evaluate the response capability of the R-11 instrument described in earlier letters. These rate-of-change indications would provide detection capability for rapidly developing leaks.

3.7.1.2 Detection of Slowly-Developing Leaks

The licensee also stated that the Sump A pump run time indication would be effective for detecting slowly increasing RCS leaks and will be credited for this application. The licensee stated that the Sump A pump run time instrumentation is required to be operable by TS LCO 3.4.16, "RCS Leakage Detection Instrumentation," and is not subject to masking due to slowly changing indications. The licensee provided the following description of the run time instrumentation:

> The Unit 1 sump pump operating range (from the high-level pump start setting to the low-level pump stop setting) is approximately 288 gallons, which is equal to

the amount of water that would be released from a 0.2 gpm leak over a 24 hour period. The Unit 2 sump pump operating range is approximately 247 gallons, which is the amount of water that would be released from a leak of approximately 0.17 gpm over a 24 hour period.

Sump pump operation on two consecutive days would indicate leakage of approximately 0.2 gpm. By trending sump pump operation each day, a 0.2 gpm leak can be detected within approximately 48 hours, after the leakage reaches the sump. More frequent checking of sump pump run time would not provide earlier leakage detection of a 0.2 gpm leak because it takes one day for the sump to fill for a 0.2 gpm leak and it takes two consecutive pump operations to identify changes from normal, routine pump operation.

The licensee committed to implement procedural guidance to approximate the rate of RCS leakage based on containment Sump A pump operating frequency or containment particulate radiation monitor indications and to clarify operator actions in response to indications of potential RCS leakage based on containment Sump A pump run time indications or containment particulate radiation monitor indications. Based on the instrument capabilities and these procedural changes, the licensee concluded that operators would detect rapidly developing leaks within 24 hours using the R-11 instrument and slowly increasing leaks within 48 hours using the containment Sump A pump run time indication.

3.7.1.3 Leak Rate Alarms

The licensee also committed to develop two new alarms on the plant ERCS to notify operators of indications consistent with RCS leakage rates of 1 gpm or less. Both of these alarms will be based on the mean count rate data from the R-11 instrument. One alarm will be based on a rate of change in mean count rate over a rolling 1 hour period, and the other will be a fixed setpoint.

3.7.1.4 Diverse Indication of Leakage

The RCS inventory balance provides an alternative method of detecting changes in RCS leakage of less than 0.2 gpm. TS Surveillance Requirement (SR) 3.4.14.1 requires that an RCS water inventory balance be performed every 24 hours while the plant is operating at steady-state to ensure that unidentified operational leakage is within its specified limits. The licensee stated in the license amendment request that the data from the RCS inventory balance would be used to establish unidentified leakage rate from the RCS.

3.7.1.5 Operator Response to Indicated RCS Leakage

The licensee committed to implement procedural guidance addressing operator actions in response to indications of potential RCS leakage based on containment Sump A pump run time indications or containment particulate radiation monitor indications. The licensee described enhancements to existing procedures for investigation of potential RCS leakage. The licensee specified that the following revisions would be implemented:

- Procedural guidance will be provided to allow operators to identify indications of RCS leakage values reaching 0.2 gpm using the R-11 containment particulate radiation monitor data displayed in ERCS or the containment Sump A runtime monitor data.
- The plant Daily RCS Leakage Test surveillance procedure will be revised to require investigative actions if indicated RCS leakage values reach 0.2 gpm using the R-11 containment particulate radiation monitor data displayed in ERCS or the containment Sump A runtime monitor data.
- Plant procedural guidance for investigating potential RCS leakage will be revised to include checking plant operating conditions and checking for confirmatory indications of leakage, including performance of an RCS inventory balance.
- Procedural guidance will be revised to require a containment entry if a potential RCS leak of 0.2 gpm or greater is identified through either the R-11 containment particulate radiation monitor data displayed in ERCS or the containment Sump A runtime monitor data and is confirmed by at least one other indication. Operators will also be directed to guidance for potential actions to be considered when planning a containment entry.

3.7.1.6 NRC Staff Evaluation of Leakage Detection Capability

The NRC staff assessed the capability of the available RCS leakage detection instrumentation to determine whether they are sufficiently reliable, redundant, and sensitive so that a margin on the detection of unidentified leakage exists for through-wall flaws to support the deterministic fracture mechanics evaluation, consistent with the guidance of SRP Section 3.6.3. The staff determined that the three credited means of quantifying unidentified leakage are sufficiently reliable because the R-11 containment particulate radiation monitor and the containment Sump A pump runtime monitor are required to be operable, and the RCS inventory balance is required to be completed on a periodic basis by technical specifications.

The NRC staff also concluded that the credited monitoring capabilities are sufficiently redundant, diverse, and sensitive to support the fracture mechanics evaluation. The licensee provided sufficient information demonstrating that the R-11 containment particulate radiation monitor would be sensitive to sudden development of a 0.2 gpm leak because the instrument would show a noticeable increase in count rate within 4 hours of the onset of such a leak. The licensee committed to install computer points in ERCS to smooth the instrument data and provide indication of rate of change in count rate. In addition, the licensee committed to install ERCS alarms that would be indicative of a 1 gpm leak based on either rate-of-change or absolute count rate, which is consistent with RG 1.45 guidelines. To reliably respond to slowly evolving leakage that may be masked when evaluating the change in particulate radiation monitor response, the licensee committed to credit the containment Sump A pump runtime monitor. In addition, the required RCS inventory balance provides a diverse method of detecting small leaks.

3.7.2 RCS Leakage Detection System Technical Specifications

The NRC staff evaluated the adequacy of the existing PINGP RCS leakage detection system TSs. As noted above, PINGP TS LCO 3.4.16 requires operability of the containment sump pump runtime monitor and one radionuclide monitor when the plant is in operational Modes 1 (Power Operation) through 4 (Hot Shutdown). The related TS LCO 3.4.14, "Operational Leakage," specifies that RCS operational leakage be limited, with no pressure boundary leakage

and less than 1 gpm unidentified leakage. To verify that these limits in TS LCO 3.4.14 are satisfied, TS SR 3.4.14.1 requires operators perform an RCS water inventory balance once every 24 hours after the plant reaches steady-state operation. These TSs ensure that the credited leakage detection capability for LBB would be available and are acceptable.

The licensee addressed the adequacy of the existing set of TSs in the enclosure to the letter dated January 14, 2011. In that enclosure, the licensee described that the analyzed leakage value of 2.12 gpm is bounded by the TS Limiting Condition for Operation (LCO) 3.4.14 limit for unidentified leakage of 1 gpm, by greater than a factor of 2. Furthermore, the licensee stated that the LBB methodology is only applicable for applications where flaws would have slow growth rates and where the affected portions of the system are not susceptible to water hammer, stress corrosion cracking, fatigue cracking, or potential for significant cyclic thermal stresses. The licensee determined crack growth from a 2.0 gpm leakage size to the 2.12 gpm analyzed leakage flaw size would take 95 days. In addition, it would take approximately 5 years for this 2.12 gpm leakage flaw to grow to critical size. Based on the NRC staff's review of this calculation, which demonstrates slow crack growth, the staff concludes that the existing unidentified leakage limit of 1 gpm in TS LCO 3.4.14 provides satisfactory margin for detecting a flaw before it could grow to the analyzed leakage flaw size and before it could become a potential pipe rupture.

As noted in the *Federal Register* Notice (60 FR 36953) accompanying the issuance of 10 CFR 50.36, the rule reflects that TSs were intended to be reserved for those conditions or limitations upon reactor operation necessary to obviate the possibility of an abnormal situation or event giving rise to an immediate threat to the public health and safety. The available margin between leakage cracks of a size that assures detectable leakage reaches the leakage detection instrumentation and larger cracks that could progress to unstable pipe ruptures provides reasonable assurance that the existing RCS Leakage TS remain acceptable with respect to the requirements of 10 CFR 50.36. Therefore, the assumed LBB leakage rate of 0.2 gpm would not pose an immediate challenge to safety and both the instruments used to detect this leakage rate and the leakage value itself used in LBB analysis may be appropriately controlled as USAR information.

3.8 Summary

On the basis of its evaluation of the LBB submittal, the NRC staff finds that the licensee has demonstrated for the subject RCS branch piping in the PINGP, Units 1 and 2, that: (1) a margin of 10 exists between the calculated leak rate from the postulated leakage flaw sizes and the RCS leakage detection system capability; (2) a margin of 2 exists between the critical flaw sizes and the leakage flaw sizes; (3) analysis input parameters (e.g., loadings and crack morphology) are applied consistent with SRP, Section 3.6.3; (4) the screening criteria of SRP, Section 3.6.3, are satisfied, including the Unit 2 pressurizer surge line; and (5) the postulated cracks have been demonstrated to be stable.

In addition, on the basis of its review of the LBB evaluation for the subject RCS branch piping at PINGP, the NRC staff finds that the licensee has demonstrated that (1) the availability of diverse instrumentation to detect leakage a factor of 10 below the calculated leak rate from the leakage flaw size; and (2) sufficient margin exists between the existing RCS Leakage TS LCO for unidentified leakage and leakage likely to be associated with a crack that could progress to an

unstable rupture that the leakage detection capability associated with LBB would be appropriately controlled as USAR information. Therefore, the proposed leakage detection capability for the subject RCS branch piping LBB is consistent with the guidance of SRP Section 3.6.3, Revision 1, and is acceptable.

Pursuant to GDC 4 of Appendix A to 10 CFR Part 50, the NRC staff concludes that the licensee is permitted to exclude consideration of the dynamic effects associated with the postulated rupture of the subject RCS piping from the current licensing basis at the PINGP, Units 1 and 2.

4.0 STATE CONSULTATION

In accordance with the Commission's regulations, the Minnesota State official was notified of the proposed issuance of the amendments. The State official had no comments.

5.0 ENVIRONMENTAL CONSIDERATION

The amendments change the requirements with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20. The NRC staff has determined that the amendments involve no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendments involve no significant hazards consideration and there has been no public comment on such finding dated May 11, 2010 (75 FR 26290). Accordingly, the amendments meet the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendments.

6.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendments will not be inimical to the common defense and security or to the health and safety of the public.

7.0 COMMITMENTS

The licensee made the following commitments in its August 9, 2011, submittal:

1. Within 180 days after approval of the LBB LAR, NSPM will implement procedural guidance to allow plant operators to approximate the quantity of RCS leakage based on containment sump A pump operating frequency or containment particulate radiation monitor indications.

2. Within 180 days after approval of the LBB LAR, NSPM will provide indications and alarms on the plant Emergency Response Computer System that will alert plant

operators to potential RCS leakage based on containment particulate radiation monitor indications.

3. Within 180 days after approval of the LBB LAR, NSPM will implement procedural guidance to clarify operator actions in response to indications of potential RCS leakage based on containment sump A pump run time indications or containment particulate radiation monitor indications.

8.0 REFERENCES

1. WCAP-12639, "Westinghouse Owners Group Pressurizer Surge Line Thermal Stratification Generic Detailed Analysis Program MUHP-1091 Summary Report," Westinghouse Electric Company, June 1990. (ADAMS Legacy Library Accession No. 9009120227 - Non-publicly available).

2. WCAP-12639 Supplement 1, "Westinghouse Owner's Group Additional Information on Pressurizer Surge Line Stratification Detailed Analysis," Westinghouse Electric Company, November 1990. (ADAMS Legacy Library Accession No. 9103200349 - Non-publicly available).

3. NRC letter to Northern States Power Company dated December 20, 1991, Subject: "Prairie Island Nuclear Generating Plant Unit No. 2 - Pressurizer Surge Line Thermal Stratification- Bulletin 88-11." (ADAMS Legacy Library Accession No. 9201080188).

4. NUREG/CR-6428, "Effects of Thermal Aging on Fracture Toughness and Charpy-Impact Strength of Stainless Steel Pipe Welds," US Nuclear Regulatory Commission, May 1996. (ADAMS ML052360567).

5. NUREG/CR-6300, "Refinement and Evaluation of Crack-Opening Analyses for Short Circumferential Through-Wall Cracks in Pipes," U.S. Nuclear Regulatory Commission, April 1995. (ADAMS Legacy Library Accession No. 9505030464 - Non-publicly available).

6. ASME Section XI Task Group for Piping Flaw Evaluation, "Evaluation of Flaws in Austenitic Steel Piping," Journal of Pressure Vessel Technology, Vol. 108, August 1986, pp. 352-366.

7. EPRI Report No. NP-6301-D "Ductile Fracture Handbook," June 1989.

8. MRP-139 NP, "Materials Reliability Program: Primary System Piping Butt Weld Inspection and Evaluation Guideline (MRP-139 NP)," Electric Power Research Institute, 1010087, July 14, 2005. (ADAMS ML052150196 - Non proprietary version).

9. D. Abdollahian and B. Chexal, "Calculation of Leak Rates Through Cracks in Pipes and Tubes," EPRI NP-3395, Electric Power Research Institute, Palo Alto, CA, December 1983. (ADAMS ML063170257 - Non-publicly available).

10. WCAP-12877, "Technical Justification for Eliminating Pressurizer Surge Line Rupture as the Structural Design Basis for Prairie Island Unit 1," Westinghouse Electric Company, March 1991. (ADAMS Legacy Library Accession No. 9106260325 - Non-publicly available).

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S. Jones, NRR/DSS/SBPB

Date of issuance: October 27, 2011

Mr. Mark A. Schimmel October 27, 2011
Site Vice President
Prairie Island Nuclear Generating Plant
Northern States Power Company - Minnesota
1717 Wakonade Drive East
Welch, MN 55089-9642

SUBJECT: PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNITS 1 AND 2 - ISSUANCE OF AMENDMENTS RE: REQUEST TO EXCLUDE THE DYNAMIC EFFECTS ASSOCIATED WITH CERTAIN POSTULATED PIPE RUPTURES FROM THE LICENSING BASIS BASED UPON APPLICATION OF LEAK-BEFORE-BREAK METHODOLOGY (TAC NOS. ME2976 AND ME2977)

Dear Mr. Schimmel:

The U.S. Nuclear Regulatory Commission has issued the enclosed Amendment No. 204 to Renewed Facility Operating License No. DPR-42 and Amendment No. 191 to Renewed Facility Operating License No. DPR-60 for the Prairie Island Nuclear Generating Plant (PINGP), Units 1 and 2, respectively.

The amendments consist of changes to the PINGP Updated Final Safety Analysis Report in response to your application dated December 22, 2009 (Agencywide Documents and Access Management System (ADAMS) Accession No. ML100200129), as supplemented by letters dated July 23, August 20, October 8, 2010, and January 14, February 23, April 6, and August 9, 2011 (ADAMS Accession Nos. ML102040612, ML102320535, ML102810518, ML110140367, ML110550582, ML110970101, and ML112220099, respectively).

A copy of our related safety evaluation is also enclosed. The Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,
/RA/
Thomas J. Wengert, Senior Project Manager
Plant Licensing Branch III-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. 50-282 and 50-306

Enclosures:
1. Amendment No. 204 to DPR-42
2. Amendment No. 191 to DPR-60
3. Safety Evaluation

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OFFICE	LPL3-1/PM	LPL3-1/LA	DCI/CPNB/ BC*	DSS/SBPB/ BC**	OGC	LPL3-1/ BC	LPL3-1/ PM
NAME	TWengert	BTully	TLupold	GCasto	BMizuno /NLO	RPascarelli	TWengert
DATE	10/17/11	10/17/11	03/17/11	10/05/11	10/25/11	10/27/11	10/27/11

OFFICIAL RECORD COPY