NMC
Committed to Nuclear Excellence

Prairie Island Nuclear Generating Plant
Operated by Nuclear Management Company, LLC

DEC 1 3 2005

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10 CFR 50.90

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

Prairie Island Nuclear Generating Plant Units 1 and 2
Dockets 50-282 and 50-306
License Nos. DPR-42 and DPR-60

License Amendment Request (LAR) To Technical Specification (TS) 5.5.14 For One-Time Extension Of Containment Integrated Leakage Rate Test Interval

Pursuant to 10 CFR 50.90, the Nuclear Management Company (NMC) hereby requests an amendment to the TS for the Prairie Island Nuclear Generating Plant (PINGP) Units 1 and 2 to revise TS 5.5.14 "Containment Leakage Rate Testing Program". The proposed changes will allow a one-time interval extension of no more than 5 years for the Type A, Integrated Leakage Rate Test (ILRT). NMC has evaluated the proposed changes in accordance with 10 CFR 50.92 and concluded that they involve no significant hazards consideration.

The proposed amendment is risk-informed and follows the guidance in Regulatory Guide (RG) 1.174, "An approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Bases". NMC has performed an analysis showing that the increase in risk resulting from the proposed amendment is small and within established guidance. NMC has also determined that defense-in-depth principles will be maintained based on both risk and other considerations.

Exhibit A contains the licensee's evaluation of this LAR. Exhibit B provides a markup of the TS page. Exhibit C provides the retyped TS page. Exhibit D provides the licensee's risk analysis associated with this LAR. Exhibit E provides a summary of the probabilistic risk assessment model revisions. Exhibit F provides peer review certification process significance level "A" and "B" findings and their disposition.

NMC requests approval of the proposed amendment by September 1, 2006 to allow NMC adequate time to prepare for ILRT performance during the Autumn 2006 Unit 2 refueling outage if this LAR is not approved. Upon NRC approval, NMC requests 30 days to implement the associated changes. In accordance with 10 CFR 50.91, NMC is notifying the State of Minnesota of this LAR by transmitting a copy of this letter and attachments to the designated State Official.

A017

Summary of Commitments

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

I declare under penalty of perjury that the foregoing is true and correct.
Executed on DEC 1 3 2005

Thomas J. Palmisano
Site Vice President, Prairie Island Nuclear Generating Plant Units 1 and 2
Nuclear Management Company, LLC

cc: Administrator, Region III, USNRC
Project Manager, Prairie Island, USNRC
Resident Inspector, Prairie Island, USNRC
State of Minnesota

Exhibits:

A. Licensee's Evaluation
B. Proposed Technical Specification Changes (mark-up)
C. Proposed Technical Specification Changes (retyped)
D. Risk Assessment for Prairie Island Nuclear Generating Plant Regarding ILRT (Type A) Extension Request
E. Summary of the Prairie Island Probabilistic Risk Assessment Revisions
F. Summary of Peer Review Certification

Exhibit A

LICENSEE'S EVALUATION

License Amendment Request (LAR) To Technical Specification (TS) 5.5.14 For One-Time Extension Of Containment Integrated Leakage Rate Test Interval

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1.0 DESCRIPTION

This LAR is a request to amend Operating Licenses DPR-42 and DPR-60 for Prairie Island Nuclear Generating Plant (PINGP) Units 1 and 2.

The Nuclear Management Company, LLC (NMC) requests Nuclear Regulatory Commission (NRC) review and approval of revised TS requirements for Surveillance Requirements for containment integrated leakage rate testing in TS 5.5.14.a to allow a one-time extension of the interval between reactor containment vessel integrated leakage rate tests (ILRTs) from 10 to 15 years.

The proposed amendment is risk-informed and follows the guidance in Regulatory Guide (RG) 1.174 (Reference 1). In accordance with RG 1.174, NMC has performed an analysis showing that the increase in risk resulting from the proposed amendment is small and within established guidance. NMC has also determined that defense-in-depth principles will be maintained based on both risk and other considerations.

2.0 PROPOSED CHANGE

A brief description of the associated proposed TS changes is provided below along with a discussion of the justification for each change. The specific wording changes to the TS are provided in Exhibits B and C.

TS 5.5.14, "Containment Leakage Rate Testing Program", Paragraph a:

The proposed license amendment would revise Technical Specification 5.5.14 to allow a one-time interval extension of no more than 5 years for the Type A, ILRT. This revision is a one time exception to the 10 year frequency of the performance-based leakage rate testing program for Type A tests as defined by Nuclear Energy Institute (NEI) document 94-01, Revision 0, "Industry Guideline For Implementing Performance-Based Option of Title 10 Code of Federal Regulations Part 50 (10CFR50), Appendix J" (Reference 2), and endorsed by 10CFR50, Appendix J, Option B. The proposed one-time exception is to the requirement to perform an ILRT at a frequency of up to 10 years, with allowance for a 15-month extension. The requested exception is to allow the ILRT to be performed within 15 years from the last ILRT.

This change is acceptable based on NMC analysis showing that the increase in risk resulting from the proposed amendment is small and within established guidance. NMC has also determined that defense-in-depth principles will be maintained based on both risk and other considerations. With this proposed change the containment safety function will continue to be met.

3.0 BACKGROUND

PINGP is a two unit plant located on the right bank of the Mississippi River approximately 6 miles northwest of the city of Red Wing, Minnesota. The facility is owned by the Northern States Power Company (NSP) and operated by NMC. Each unit at PINGP employs a two-loop pressurized water reactor designed and supplied by Westinghouse Electric Corporation. The initial PINGP application for a Construction Permit and Operating License was submitted to the Atomic Energy Commission (AEC) in April 1967. The Final Safety Analysis Report (FSAR) was submitted for application of an Operating License in January 1971. PINGP Unit 1 began commercial operation in December 1973 and Unit 2 began commercial operation in December 1974.

PINGP was designed and constructed to comply with NSP's understanding of the intent of the AEC General Design Criteria (GDC) for Nuclear Power Plant Construction Permits, as proposed on July 10, 1967. PINGP was not licensed to NUREG-0800, "Standard Review Plan (SRP)."

3.1 Containment Description

The PINGP primary containment system is a freestanding carbon steel cylindrical pressure vessel with hemispherical dome and ellipsoidal bottom (the Reactor Containment Vessel), with an internal net free volume of 1,320,000 cubic feet, and its associated engineered safety features systems, capable of withstanding a design internal pressure of 46 pounds per square inch gage and a temperature of 268 degrees Fahrenheit. The containment systems include fan coil units and internal containment sprays capable of rapidly absorbing the energy released by a loss of coolant accident.

The containment systems are described in detail in Chapter 5 of the PINGP Updated Safety Analysis Report (USAR).

3.2 Current Requirements

TS 5.5.14.a requires that a program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in RG 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995, as modified by approved exceptions in accordance with RG 1.163 (Reference 3). Regulatory Position C.1 of RG 1.163 states that licensees should establish test intervals based upon the criteria in Section 11.0 of NEI 94-01 (Reference 2). Section 11.0 of NEI 94-01 references Section 9.0 which allows ILRTs to be performed at a frequency of 1 per 10 years if the calculated leakage rate for two consecutive previous tests is less than 1.0 L_a. L_a is defined in PINGP TS 5.5.14.c as 0.25 weight percent of the contained air per 24 hours at the peak test pressure, P_a, of 46.0 psig. The PINGP reactor containment vessel has met this criterion and therefore qualifies for the 10-year frequency.

3.3 Basis for Current Requirements

The maximum allowable containment leakage rate, L_a, specified in TS 5.5.14, "Containment Leakage Rate Testing Program", ensures that the total containment leakage volume will not exceed the value assumed in the accident analyses at the peak accident pressure. As an added conservatism, TS 5.5.14.d limits the measured overall integrated leakage rate to less than or equal to 0.75 L_a during performance of periodic tests to account for possible degradation of the containment leakage barriers between leakage tests.

The performance-based ILRT requirements of Option B of 10CFR50, Appendix J, provide an alternative to the 3 tests per 10-year frequency specified by the prescriptive requirements of Option A of 10CFR50, Appendix J. As documented in RG 1.163, the NRC has endorsed NEI 94-01 as providing acceptable methods for complying with the requirements of Option B of 10CFR50, Appendix J. NEI 94-01 specifies an ILRT frequency of 1 test per 10 years if certain performance criteria are met. The basis for the 1 test per 10-year frequency is described in Section 11.0 of NEI 94-01, which states that NUREG-1493 (Reference 4) provides the technical basis to support rulemaking that established Option B. That basis consisted of qualitative and quantitative assessments of the risk impact (in terms of increased public dose) associated with a range of extended leakage rate test intervals. NEI undertook a similar study, the results of which are documented in Electric Power Research Institute (EPRI) report TR-104285 (Reference 5). The EPRI study determined a reduction in the frequency of ILRTs from 3 tests per 10 years to 1 test per 10 years would result in an incremental risk contribution of 0.035 percent. This value is comparable to the range of risk increases (0.002 percent to 0.14 percent) presented in NUREG-1493 for the same frequency reduction. Additionally, NUREG-1493 described the increase in risk resulting from an even lower frequency, 1 test per 20 years, as "imperceptible".

3.4 Reason for Requesting Amendment

Extension of the ILRT interval from 10 years to 15 years would eliminate the need to perform an ILRT for PINGP Units 1 and 2 during the 2006 and 2008 outages. This would save a total of approximately 0.6 person-rem exposure. This would also result in an estimated monetary savings of about $1,000,000.00. NMC is requesting this license amendment to obtain these personnel exposure and monetary savings.

Thus, NMC requests NRC review and approval of the proposed TS change which provides a one-time extension of the containment ILRT interval from 10 years to 15 years for each unit.

4.0 TECHNICAL ANALYSIS

The proposed amendment would authorize a one-time extension of the ILRT interval from 10 years to 15 years for PINGP. The proposed amendment is supported by both risk and non-risk considerations.

4.1 Risk Assessment

An evaluation was performed to assess the risk impact of a one-time extension of the currently allowed containment Type A ILRT frequency from 10 years to 15 years. The extension would allow for substantial cost savings since the ILRT could be deferred to subsequent scheduled refueling outages for PINGP. The proposed change would impact testing associated with the current surveillance test for Type A leakage. The risk assessment follows the guidelines from NEI 94-01 (Reference 2), the methodology used in Electric Power Research Institute (EPRI) Topical Report (TR) -104285 (Reference 5) and the NRC regulatory guidance on the use of PRA findings and risk insights in support of the request to change PINGP's licensing basis as outlined in RG 1.174 (Reference 1). In addition, for comparison purposes, the risk assessment was also performed using two more recent (although not yet issued in final, approved form) studies. These methodologies are presented in the NEI Interim Guidance (Reference 6), and in EPRI TR-1009325 (Reference 7). Although these methodologies generally produce more conservative results than do the earlier methodologies, they build upon the work of the earlier studies, and much of the analyses developed from application of the EPRI TR-104285 methodology remains applicable for use in these more recent studies.

The findings for Prairie Island confirm the general findings of previous studies, namely, that the increased risk to the public due to the extension of the ILRT interval is very low population surrounding the PINGP. Based on the results from Sections 5 through 7, the following conclusions regarding the assessment of the plant risk are associated with extending the Type A ILRT test from ten years to fifteen years:

- There is no change in the at-power core damage frequency (CDF) associated with the ILRT test interval extension. Therefore, this is within the RG 1.174 acceptance guidelines.

- RG 1.174 provides guidance for determining the risk impact of plant-specific changes to the licensing basis. RG 1.174 defines very small changes in risk as resulting in increases of CDF below 1E-6/yr and increases in (large, early release frequency) LERF below 1E-7/yr. Since the ILRT does not impact CDF, the relevant criterion is LERF. The increase in LERF resulting from a change in the Type A ILRT test frequency from once-per-ten-years to once-per-fifteen years is between 5.33E-9/yr (7.46E-9/yr) and 5.93E-08/yr (8.30E-8/yr). Therefore, increasing the ILRT interval from 10 to 15 years is considered to result in a very small change to the PINGP risk profile.

- The proposed change in the Type A test frequency (from once-per-ten-years to once-per-fifteen-years) increases the total integrated plant risk by significantly less than 1% for both units. Therefore, the risk impact of this change, when compared to other severe accident risks, is negligible.

- The change in Conditional Containment Failure Probability (CCFP) of less than 1% for both units is judged to be insignificant and reflects sufficient defense-in-depth.

The above results demonstrate that the increases in risk and LERF resulting from the proposed amendment are within established guidelines and that defense-in-depth principles would be maintained. The complete assessment is contained in Exhibit D.

4.2 Other Considerations

Consistent with the defense-in-depth philosophy provided in RG 1.174, NMC has assessed other considerations relevant to the proposed amendment. These are discussed below.

4.2.1 ILRT History

TS 5.5.14.a requires the measurement of the containment leakage rate. TS 5.5.14.d establishes the limit for the measured overall integrated containment leakage rate as 0.75 of the containment air per 24 hours at P_a. The results of all Type A tests for PINGP are reported below using the 95 percent upper confidence level (UCL) estimate of leakage rate.

The results of all Type A tests performed at PINGP have met the acceptance criteria.

These results demonstrate a history of satisfactory performance for both leak tightness and structural integrity of the containment vessel.

Unit 1

95% UCL wt%/day	Test Pressure (1)	Date
0.0429	46 psig	12/1/97
0.0685	23 psig	6/24/94
0.0459	23 psig	6/21/91
0.0450	23 psig	9/18/88
0.0247	23 psig	2/20/85
0.0806	23 psig	10/9/80
0.0386	23 psig	4/15/77
0.0189	23 psig	7/4/73
0.0234	46 psig	7/4/73

Unit 2

95% UCL wt%/day	Test Pressure (1)	Date
0.0391	46 psig	3/7/97
0.0144	23 psig	1/1/93
0.0272	23 psig	4/21/89
0.0402	23 psig	10/16/85
0.0206	23 psig	3/27/81
0.0628	23 psig	12/5/77
0.0257	23 psig	8/1/74
0.0156	46 psig	8/1/74

(1) PINGP license amendments 126/118, which implemented the amended regulation 10 CFR Part 50, Appendix J, Option B, removed the performance of reduced pressure ILRT testing from the PINGP TS.

4.2.2 <u>Local Leakage Rate Testing (LLRT)</u>

As documented in NUREG-1493 (Reference 4), industry experience has shown that most ILRT failures result from leakage that is detectable by local leakage rate testing (Type B and C testing as defined in 10CFR50, Appendix J). The PINGP LLRT requirements per the Containment Leakage Rate Testing Program are unaffected by this proposed amendment. The LLRT program will, therefore, provide continuing assurance that the most likely sources of leakage will be identified and repaired.

4.2.3 Containment Inservice Inspection Program (IWE)

PINGP has established a containment inservice inspection program that implements the requirements for examination and testing of American Society of Mechanical Engineers (ASME) Code Section XI and 10CFR50.55a Class MC components. This program was developed in accordance with the requirements of the 1992 Edition with the 1992 Addenda of the ASME Boiler and Pressure Vessel Code, Section XI, Division 1, Subsection IWE, as modified by NRC final rulemaking of 10CFR50.55a, published in the Federal Register on August 8, 1996. The scope of the program includes all the containment surfaces, pressure retaining welds, containment surfaces requiring augmented examination, seals, gaskets, moisture barriers, pressure retaining dissimilar metal welds, pressure retaining bolting and pressure retaining components that are required to be examined. The first 10-year inspection interval was established from September 9, 1996, to September 9, 2008 as defined in PINGP program procedures.

The containment inservice inspection program is unaffected by the proposed amendment, and will continue to provide a high degree of assurance that any degradation of the containment will be detected and corrected before it can result in a leakage path.

4.2.3.1 *Approved Alternatives to Subsection IWE Requirements*

There are seven NRC approved alternatives to Subsection IWE requirements approved for PINGP. Relief Requests MC-2 and MC-3 are the only relief requests that are associated with the Containment Leakage Rate Testing Program.

Relief Request MC-2:

> The ASME Code, Section XI, 1992 edition, 1992 addenda, IWE-2500, Table IWE-2500-1, Examination Category E-D, Items E5.10 and E5.20, requires seals and gaskets on airlocks, hatches, and other devices to be visually examined (VT-3) once each interval to assure containment leak-tight integrity.
>
> Relief was requested from performing the Code-required visual examination (VT-3) on the seals and gaskets of Class MC pressure-retaining components as specified above.
>
> The leak-tightness of seal and gasket joints is tested in accordance with 10 CFR Part 50, Appendix J. This testing is performed at least once each inspection interval. No additional alternative examinations to the visual examination (VT-3) of the seals and gaskets are performed.

Relief Request MC-3:

The ASME Code, Section XI, 1992 edition, 1992 addenda, Table IWE-2500-1, Examination Category E-G, "Pressure Retaining Bolting," Item E8.20, requires that torque and tension testing shall be performed on pressure retaining bolts.

Relief was requested from the ASME Code, Section XI, 1992 edition, 1992 addenda, Table IWE-2500-1, Examination Category E-G, Item E8.20. Table IWE-2500-1 requires a bolt torque or tension test on bolted connections that have not been disassembled and reassembled during the inspection interval.

The following examinations and tests required by Subsection IWE ensure the structural integrity and the leak-tightness of Class MC pressure-retaining bolting, and, therefore, no additional alternative examinations were proposed.

1. Exposed surfaces of bolted connections are visually examined in accordance with requirements of Table IWE-2500-1, Examination Category E-G, "Pressure Retaining Bolting," Item No. E8.10, and

2. Bolted connections shall meet the pressure test requirements of Table IWE-2500-1, Examination Category E-P, "All Pressure Retaining Components," Item E9.40. Additionally, inspections for excessive leakage of pressure unseating penetrations are performed during Type A testing.

The request for the one time extension of the ILRT interval has no affect on the performance of the required alternate testing activities described in these relief requests and their associated NRC Staff Evaluations. Additional information can be found in the relief request, “Prairie Island Nuclear Generating Plant, Units 1 and 2 – Evaluation of Relief Request Related to the First Interval Inservice Inspection Program for Metal Containment (TAC Nos. MB2784 and MB2785)” dated June 11, 2002.

4.2.3.2 *Containment Inservice Inspection Program (IWE) Implementation*

The PINGP containment inspection plan, establishes the administrative, managerial, and implementation controls for the IWE Inservice Inspection Program Plan (IWE Program) for the first ten-year inspection interval at the PINGP, Units 1 and 2. The IWE Inspection Program identifies the ASME Section XI Subsection IWE components or items required to be examined in accordance with the 1992 Edition with Addenda through 1992 of the ASME Boiler and Pressure Vessel Code Section XI (the Code) within the limitations and modifications required by 10CFR 50.55a, Codes and Standards. The 10CFR50 Appendix J program, Containment Coatings, Repair Replacement and Maintenance Rule Programs all interface with the IWE Inspection Program.

The concrete shield buildings at PINGP are not pressure retaining components, hence, an IWL program was not developed. IWL is not applicable to PINGP.

4.2.3.3 *Components Exempt from Examination*

Components outside the examination boundary include vessels, parts and appurtenances that are outside the boundaries of the containment. Some components are within the examination boundary, however, are exempt from examination. Components made inaccessible during construction or other modifications are exempt from examination. Seals and gaskets in containment penetrations necessary for leak-tight integrity are not required to be inspected per relief request MC-2.

Inaccessible surface areas of IWE components or items are identified in the IWE Component Database and are exempt from examination because they have met the requirements of the original Construction Code or Construction Design Specification. For PINGP Units 1 and 2, the areas that have been identified as inaccessible are those embedded in concrete and behind the moisture barrier at the steel concrete interface. Areas embedded in concrete are located below the 706' 6" elevation and around the fuel transfer canal. Although these areas are considered inaccessible for performing routine IWE examinations, these areas may be subject to other examinations if they are adjacent to degraded areas as required by 10CFR 50.55a(b)(2)(ix)(A).

4.2.3.4 *IWE Examination Category E-A, Containment Surfaces*

Components to be examined are the accessible interior and exterior containment vessel surface areas. The examination includes structures that are part of reinforcing structures, such as stiffening rings, manhole frames and reinforcement around openings. The examination also includes the weld metal and the base metal for ½ inch beyond the edge of the weld. A General Visual Examination is performed in accordance with the plant procedure, "General Visual Examination Of The Containment Liner For ASME Subsection IWE", to uncover any evidence of structural integrity or leak tightness concerns. This procedure also fulfills the 10CFR50 Appendix J requirement for a General Visual Inspection prior to any Type A test. A VT-3 examination is performed to determine the general mechanical and structural condition of IWE components or items and their supports and to assess such things as missing parts, debris, corrosion, wear, clearances, and physical displacements.

4.2.3.5 *IWE Examination Category E-B, Pressure Retaining Welds*

Examination requirements specified in ASME Section XI Code are optional per 10CFR 50.55a(b)(2)(ix)(C) and will not be performed. Examination Category E-A requirements are considered sufficient to identify any degraded condition for containment penetration welds.

4.2.3.6 *IWE Examination Category E-C, Containment Surfaces Requiring Augmented Examination*

4.2.3.6.1 Items E4.11 and E4.12

This category includes IWE component areas selected for augmented examination because of known existing degraded conditions. 100% of surface areas likely to experience accelerated degradation and aging require augmented examination. In addition, interior and exterior containment surfaces that are subject to excessive wear causing a loss of protective coatings, deformation, or material loss are also examined. Other areas, in addition to those specified, may be added after initial assessment of the degraded condition as appropriate. Visual examinations (VT-1) are performed for surface areas accessible from both sides. Volumetric ultrasonic thickness measurements are performed for surface areas accessible from only one side.

4.2.3.7 *IWE Examination Category E-D Seals, Gaskets, and Moisture Barriers*

4.2.3.7.1 Items E5.10, Seals and E5.20, Gaskets

This category includes seals and gaskets on airlocks, hatches, electrical penetrations; and other devices required to assure containment leak-tight integrity of the containment vessel. Table IWE-2500-1 requires a VT-3 examination for these components however Relief Request MC-2, "VT-3 Examination Of Seals And Gaskets", modifies this requirement. Per Relief Request MC-2 VT-3 inspections are not required. As an alternative the 10CFR50 Appendix J program is used to verify the integrity of these components. When penetrations are disassembled, the seals and gaskets are inspected and replaced as necessary per plant procedures and do not require a VT-3 examination. Upon assembly of the penetration a leak rate test is performed per the Appendix J program.

4.2.3.7.2 Item E5.30, Moisture Barriers

This category includes the non-pressure retaining moisture barriers at the concrete floor slab to liner plate interface (inside the containment vessel at 711'3" elevation and outside the vessel at 706'6" elevation. VT-3 examinations are performed on items required to protect the containment vessel liner plate to maintain containment leak tight integrity, although they are not part of the pressure retaining boundary. They are considered part of the IWE examination boundary.

4.2.3.8 *IWE Examination Category E-F, Pressure Retaining Dissimilar Metal Welds*

Examination requirements specified in ASME Section XI Code are optional per 10CFR 50.55a(b)(2)(ix)(C) and will not be performed. Examination Category E-A requirements are considered sufficient to identify any degraded condition for containment penetration welds.

4.2.3.9 *IWE Examination Category E-G, Pressure Retaining Bolting*

4.2.3.9.1 Item E8.10, Bolted Connections

Pressure retaining bolted connection examinations include inspection of bushings, bolts, studs, nuts, washers, and threads in the base flange material and flange ligaments between threaded stud holes as appropriate. VT-1 examinations are performed on bolted connections. Inspection of bushings, threads, threads in flange connections, and ligaments in the flange base material is required only when the connection is disassembled. When disassembly is not required, the connection remains in place under tension and all visible surfaces are examined.

4.2.3.9.2 Item E8.20, Bolted Connections

Relief request MC-3 provides exemption from the requirement to perform bolt torque or tension tests. The visual examinations of Item Number E8.10 with 10CFR50 Appendix J tests are adequate to ensure integrity of the bolted connection.

4.2.3.10 *IWE Examination Category E-P, All Pressure Retaining Components*

Item numbers E9.10, Pressure Retaining Boundary, E9.20, Containment Penetration Bellows, E9.30, Airlocks and E9.40, Seals and Gaskets:

The requirements to test the items in this category are met by the 10CFR50 Appendix J program, "Containment Leakage Rate Testing". Test frequencies, acceptance criteria and components included are maintained in the 10CFR50 Appendix J program.

4.2.3.11 *IWE Acceptance Standards*

4.2.3.11.1 Visual Examination of Containment Surfaces

The following criteria are used when performing VT-1 or VT-3 examinations on coated surfaces per IWE-3510, "Standard for Examination Category E-A, Containment Surfaces":

Evidence of flaking, blistering, peeling, discoloration and other signs of distress.

The following criteria are used when performing VT-1 or VT-3 examinations on non-coated surfaces per IWE-3510, "Standard for Examination Category E-A, Containment Surfaces":

> Evidence of cracking, discoloration, wear, pitting, excessive corrosion, arc strikes, gouges, surface discontinuities, dents and other signs of surface irregularities.

Conditions that meet or exceed the threshold are considered suspect and are reported to engineering for evaluation. The source of discoloration such as rust, staining, accumulated dirt, or dirt containing iron compounds is identified. If the source is from a component other than an MC component and is not detrimental to the MC component there is no need to document the condition as an indication. If the source is from the MC component it shall be recorded if it exceeds the criteria stated here. Degradation that is not detrimental to the pressure retaining boundary such as general surface corrosion on a non-coated component is acceptable.

4.2.3.11.2 Ultrasonic Examinations of Containment Surfaces

The following criteria are used when performing ultrasonic examinations on containment surfaces per IWE-3512.3, "Ultrasonic Examination":

> Material loss of more than10% of the nominal containment wall thickness or that are projected to exceed 10% of the nominal containment wall thickness prior to the next examination.

4.2.3.11.3 Visual Examination of Seals, Gaskets, and Moisture Barriers

The following criteria are used when performing VT-3 examinations on seals, gaskets, and moisture barriers per IWE-3513.1 VT-3 "Visual Examinations":

> Wear, damage, erosion, tear, surface cracks, or other defects that may violate the leak-tight integrity.

4.2.3.11.4 Visual Examination of Pressure Retaining Bolting

The following criteria are used when performing VT-1 examinations on pressure retaining bolting per IWE-3515, "Standards for Examination Category E-G, Pressure Retaining Bolting":

> Examine for defects, which may cause the bolted connection to violate either the leak-tight or structural integrity.

Any indications recorded are evaluated as to the effect of the indication on the ability of the containment vessel to meet the containment barrier function. Inservice nondestructive examination results are compared with the recorded results of the preservice or prior inservice examinations if such examinations exist. The results are evaluated by plant engineering.

4.2.4 Containment Inspection History

As stated above, the ASME Section XI, Subsection IWE inspection plan was implemented for PINGP on September 9, 1996. All inspections have been completed through the second period of the first 10-year surveillance interval. There are currently areas identified at PINGP that require augmented inspection. These areas are as follows:

4.2.4.1 *Unit 1 Refueling Cycle 19*

Examination reports show indications that exceeded either the IWE-3510.2 VT-3 visual examination on coated areas or IWE-3510.3 VT-3 visual examination on non-coated areas. Many of the indications of corrosion were removed and the components recoated, however, successive inspections are required by IWE-3122.4 per the requirements of IWE-2420 (b) and (c). These components are scheduled for inspection per the Code. If no change is detected they can be examined at the normal frequency as required by the Code.

Subsequent inspections have determined that the indications on the un-repaired components have not changed. Subsequent inspections have not identified new indications on components that were repaired.

4.2.4.2 *Cooling Water Penetrations, Units 1 and 2*

The cooling water lines to and from the fan coil units in containment showed widespread surface corrosion, blistering of the paint, surface irregularities from the corrosion, and preliminary indication of outside diameter pitting. Surface irregularities were generally less than 1/16th inch in depth. The design wall thickness is 0.906 inch (8 inch schedule 160) for the penetration piping and 3 inches for the containment penetration reinforcement. The area is covered with insulation and condensation, from the relatively cool lines, provides the moisture necessary for corrosion. Compared to the interior of the piping directly on the auxiliary building side of the penetrations, the corrosion on the outside of the piping penetration is much less. The lines and penetrations were repainted and the penetrations are scheduled for inspection per IWE-2420(a) and (b).

Follow-up inspections have not identified new indications for these repainted penetrations.

4.2.4.3 *Indications Above the Moisture Barrier, Unit 1*

Paint is missing directly above the moisture barrier due to inadequate coverage of the paint or scrapes. These areas contain light surface corrosion. There is no pitting of the metal, or flaking or blistering of nearby paint. The extent of the corrosion does not appear to get worse as it nears the moisture barrier. This is not in an area where moisture accumulates. The corrosion has not resulted in a loss of thickness to the containment vessel wall in the areas that are visible. Because the corrosion is obviously due to the lack of paint on the vessel wall in these areas and moisture from the containment atmosphere, no degradation below the moisture barrier, which is inaccessible, is suspected. The associated plates are scheduled for inspection during the next three periods per IWE-2420(a) and (b).

Subsequent inspections have determined that these indications have remained unchanged from previous inspections.

4.2.4.4 *RHR Re-circulation Suction Sump, Units 1 and 2*:

Areas identified as suspect are the RHR sump B penetrations. Water was noted coming from around the pipe sleeve. A film of water could be seen running down the sloped wall behind the flange while the refueling cavity was full. There was no external indication of corrosion such as rust stains, or spalling of the concrete or grout in the area. Due to the location of the water, the water was in contact with the containment vessel wall and may have caused corrosion in inaccessible areas. The grout around the pipe sleeves was removed to inspect behind the plate. No degradation was identified behind the plate. Borated water was first noted when the refueling pool was flooded. After the refueling pool was drained, accumulation of water in sump B and on the containment basement floor stopped. Therefore, the source of the water is either the refueling pool or the fuel transfer tube. The period of wetting of the concrete and the steel shell is about 15 days during the time when the refueling pool is flooded. The wetting could possibly have occurred every outage (approximately every 20 months) for the past few outages. At other periods when the unit is operating, the source of water was not present and the joints and surfaces should have been dry. An evaluation was performed of the above issue with the following conclusions:

> The effect of borated water leaks on structural material inside the Reactor Building is in the worst case very minimal and does not affect the capability of the structure to perform its intended function.
>
> It is prudent to investigate, determine, and fix the area where the leaks occur so that future leaks do not occur. There is a remote possibility that several cycles of wetting and drying could concentrate the boric acid solution to the extent that a strong solution could corrode the containment steel plate and compromise its pressure retaining capability.

The RHR re-circulation sump B is scheduled for inspection during the next three periods per IWE-2420(a) and (b).

Follow up inspections have determined that there has been no change following initial identification.

4.2.4.5 *Main Steam and Main Feedwater Penetrations, Units 1 and 2*

The inspection of the PINGP containments have identified areas of paint flaking, blistering and pealing around some of the Main Steam and Main Feedwater penetrations. The coating degradation is limited to the penetration and the immediate area around the penetrations. It is suspected that the high temperature is causing the failure of the coating. Under the pealing and flaking paint, the primer is intact with no signs of degradation. As required by IWE-3122.4 successive inspections are scheduled in accordance with IWE-2420 (b) and (c) for areas with identified degraded coating. To date, no successive inspections have been performed.

4.2.4.6 *Hot Containment Penetration Bellows*

In reviewing similar amendment requests from other licensees, the NRC has noted that stainless steel containment penetration bellows have been found to be susceptible to trans-granular stress corrosion cracking. As documented in NRC Information Notice 92-20 (Reference 8), leakage through such bellows may not be readily detectable by LLRTs. PINGP has penetration assemblies that incorporate two-ply mechanical bellows. The review of plant drawings indicates that wire mesh is installed between the two-plies of each bellows assembly, ensuring that an adequate gap exists to measure leakage when performing the required Type B tests.

The LLRT administrative acceptance criterion for measured leakage through these penetrations is very low at 300 standard cubic centimeters per minute (SCCM) except for the fuel transfer tube which is not accessible, so a higher acceptance criteria of 1000 SCCM is used. These penetrations have been tested per the PINGP Containment Leakage Rate Testing Program with satisfactory results. During the Unit 2 ILRT of March 1997, the pipe bellows were soap tested during the performance of the ILRT. No leaks were found.

4.2.5 <u>Maintenance Rule</u>

The containment Isolation function of limiting the release of radioactive fission products following an accident has been classified as high risk significant and its condition is monitored pursuant to 10CFR50.65 in accordance with the PINGP Maintenance Rule program. Operability of the containment isolation equipment is ensured by compliance with TS Sections 3.3, 3.6, 3.8, and 5.5. The proposed amendment affects only the ILRT requirements and has minimal impact.

4.3 Conclusions

This LAR proposes a one-time containment ILRT interval extension for each unit from 10 years to 15 years. NMC has demonstrated through a risk assessment and deterministic considerations that the containment for each unit will continue to perform its safety function following issuance of the proposed TS change. Since the containment safety function will continue to be provided, operation of the Prairie Island Nuclear Generating Plant with this revised Technical Specification will continue to protect the health and safety of the public.

5.0 REGULATORY SAFETY ANALYSIS

5.1 No Significant Hazards Consideration

The Nuclear Management Company has evaluated whether or not a significant hazards consideration is involved with the proposed amendment by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

1. **Do the proposed changes involve a significant increase in the probability or consequences of an accident previously evaluated?**

   Response: No

   This license amendment proposes to revise the Technical Specifications to allow for the one time extension of the containment integrated leakage rate test interval from 10 to 15 years. The containment vessel function is purely mitigative. There are no design basis accidents initiated by a failure of the containment leakage mitigation function. The extension of the containment integrated leakage rate test interval will not create any adverse interactions with other systems that could result in initiation of a design basis accident. Therefore, the probability of occurrence of an accident previously evaluated is not significantly increased.

   The potential consequences of the proposed change have been quantified by analyzing the changes in risk that would result from extending the containment integrated leakage rate test interval from 10 to 15 years. The increase in risk in terms of person-rem per year within 50 miles resulting from design basis accidents was estimated to be of a magnitude that NUREG-1493, "Performance-Based Containment Leak-Test Program", indicates is imperceptible. The Nuclear Management Company has also analyzed the increase in risk in terms of the frequency of large early releases from accidents. The increase in the large early release frequency resulting from the proposed extension was determined to be within the guidelines published in Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Current Licensing Basis". Additionally, the proposed change maintains defense-in-depth by preserving a reasonable balance among prevention of core damage, prevention of containment failure, and consequence mitigation. The Nuclear Management Company has determined that the increase in conditional containment failure probability from reducing the containment integrated leakage rate test frequency from 1 test per 10 years to 1 test per 15 years would be small.

Continued containment integrity is also assured by the history of successful containment integrated leakage rate tests, and the established programs for local leakage rate testing and in-service inspections which are unaffected by the proposed change. Therefore, the probability of occurrence or the consequences of an accident previously analyzed are not significantly increased.

2. **Do the proposed changes create the possibility of a new or different kind of accident from any accident previously evaluated?**

Response: No

The proposed change to extend the containment integrated leakage rate test interval from 10 to 15 years does not create any new or different accident initiators or precursors. The length of the containment integrated leakage rate test interval does not affect the manner in which any accident begins. The proposed change does not create any new failure modes for the containment and does not affect the interaction between the containment and any other system. Thus, the proposed changes do not create the possibility of a new or different kind of accident from any previously evaluated.

3. **Do the proposed changes involve a significant reduction in a margin of safety?**

Response: No

The risk-based margins of safety associated with the containment integrated leakage rate test are those associated with the estimated person-rem per year, the large early release frequency, and the conditional containment failure probability. The Nuclear Management Company has quantified the potential effect of the proposed change on these parameters and determined that the effect is not significant. The non-risk-based margins of safety associated with the containment integrated leakage rate test are those involved with its structural integrity and leak tightness. The proposed change to extend the containment integrated leakage rate test interval from 10 to 15 years does not adversely affect either of these attributes. The proposed change only affects the frequency at which these attributes are verified. Therefore, the proposed change does not involve a significant reduction in margin of safety.

Based on the above, the Nuclear Management Company concludes that the proposed amendment presents no significant hazards consideration under the standards set forth in 10 CFR 50.92(c) and, accordingly, a finding of "no significant hazards consideration" is justified.

5.2 Applicable Regulatory Requirements/Criteria

5.2.1 Title 10 Code of Federal Regulations Part 50 Appendix J

Title 10 of the Code of Federal Regulations (CFR) Part 50, Appendix J, Option B requires that a Type A test be conducted at a periodic interval based on historical performance of the overall containment system. The Prairie Island Nuclear Generating Plant Technical Specification 5.5.14, "Containment Leakage Rate Testing Program," requires that leakage rate testing be performed as required by 10 CFR Part 50, Appendix J, Option B, as modified by approved exemptions, and in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995. This Regulatory Guide endorses, with certain exceptions, Nuclear Energy Institute (NEI) Report NEI 94-01, Revision 0, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J," dated July 26, 1995.

A Type A test is an overall (integrated) leakage rate test of the containment structure. NEI 94-01 specifies an initial test interval of 48 months, but allows an extended interval of 10 years, based upon two consecutive successful tests. There is also a provision for extending the test interval an additional 15 months in certain circumstances. The most recent two Type A tests at the Prairie Island Nuclear Generating Plant have been successful, so the current interval requirement is 10 years.

The Nuclear Management Company is requesting a change to Technical Specification 5.5.14 which would add a one-time exception from the guidelines of Regulatory Guide 1.163 and NEI 94-01, Revision 0, regarding the Type A test interval for the Prairie Island Nuclear Generating Plant. Specifically, the proposed Technical Specification change allows a one-time extension of the containment integrated leak rate test interval from 10 years to 15 years.

The technical analysis for the proposed license amendment is based on risk related and non-risk related considerations. A risk analysis was performed which demonstrated that the increases in estimated person-rem and containment large early release frequency are consistent with guidance provided in Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Current Licensing Basis", and NUREG-1493, "Performance-Based Containment Leak-Test Program". The Nuclear Management Company has also demonstrated that defense-in-depth would be provided by the low increase in the conditional containment failure probability, and by non-risk based considerations such as the containment integrated leakage rate test results and containment inspection history, and the ongoing local leakage rate test and inservice inspection programs.

5.2.2 <u>Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Bases"</u>

Regulatory Guide 1.174 provides an acceptable method for licensees to use in assessing the nature and impact of licensing basis changes when the licensee chooses to support the changes with risk information. The Nuclear Management Company has performed a probabilistic risk assessment using the guidance of Regulatory Guide 1.174 to support the proposed Technical Specification change which allows a one-time extension of the containment integrated leakage rate test interval from 10 years to 15 years. The applicable guidance in Regulatory Guide 1.174 is provided as an acceptable change in the annual large early release frequency increase and the total large early release frequency. The increase in the large early release frequency resulting from the proposed extension was determined to be within the guidelines published in Regulatory Guide 1.174 when the containment integrated leakage rate test interval is extended to 15 years one time for each unit. Thus, the proposed Technical Specification changes meet the guidance of Regulatory Guide 1.174, which provides a basis for issuance by the NRC.

5.2.3 <u>Regulatory Requirements/Criteria Conclusions</u>

In conclusion, based on the considerations discussed above, (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 amendment will not be inimical to the common defense and security or to the health and safety of the public.

6.0 ENVIRONMENTAL CONSIDERATION

A review has determined that the proposed amendment would change a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10 CFR 20, or would change an inspection or surveillance requirement. However, the proposed amendment does not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluent that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed amendment meets the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed amendment.

7.0 PRECEDENT LICENSING ACTIONS

The NRC has approved one-time extensions of the ILRT interval to 15 years based on risk and non-risk based considerations for other licensees including Waterford Steam Electric Station, Unit 3 (Waterford 3) (Reference 9), and Kewaunee Nuclear Power Plant (Kewaunee) (Reference 10).

NMC considers Amendment No. 198 to the operating license for Kewaunee and Amendment No.178 to the operating license for the Waterford 3 as valid precedents. In submittals dated June 20, 2003 and December 12, 2003 for Kewaunee (References 11 and 12) and July 23, 2001, September 21, 2001 and November 8, 2001 for Waterford 3 (Reference 13, 14 and 15), the licensees presented their case and provided all requested additional information for the purpose of obtaining approval of an extended interval (15 years) for the next ILRT. The NRC subsequently granted both licensees approval of their requests.

Both of the submittals, Waterford 3 and Kewaunee, were reviewed for applicability to the PINGP Units 1 and 2 submittal. The following precedents were found:

> PINGP has hot containment penetration bellows assemblies that incorporate two-ply mechanical bellows. The review of plant drawings indicates that wire mesh is installed between the two-plies of each bellows assembly, ensuring that an adequate gap exists to measure leakage when performing the required Type B tests. Waterford 3 and Kewaunee also have similar penetration bellows assemblies.
>
> The PINGP primary containment system is a freestanding carbon steel cylindrical pressure vessel with hemispherical dome and ellipsoidal bottom (the Reactor Containment Vessel), with an internal net free volume of 1,320,000 cubic feet, and its associated engineered safety features systems, capable of withstanding a design internal pressure of 46 pounds per square inch gage and a temperature of 268 degrees Fahrenheit. The PINGP containment is identical to the Kewaunee containment. The Waterford 3 containment, which is larger than both the PINGP and Kewaunee, is also a freestanding carbon steel cylindrical pressure vessel with hemispherical dome and ellipsoidal bottom.
>
> The risk assessments performed for PINGP and Kewaunee used the guidelines of NEI 94-01, the methodology used in EPRI TR-104285, the EPRI "Interim Guidance for Performing Risk Impact Assessments in Support of One-Time Extensions for Containment Integrated Leakage Rate Test Surveillance Intervals", dated November 2001, and the regulatory guidance from NRC Regulatory Guide 1.174.

8.0 REFERENCES

1. Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk–Informed Decisions on Plant-Specific Changes to the Current Licensing Basis," Revision 1, dated November 2002.

2. Nuclear Energy Institute document NEI 94-01,"Industry Guideline for Implementing Performance-Based Option of 10CFR Part 50, Appendix J," dated July 26, 1995.

3. Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program", dated September 1995.

4. NUREG-1493, "Performance-Based Containment Leak-Test Program," dated September 1995.

5. Electric Power Research Institute report TR-104285 "Risk Impact Assessment of Revised Containment Leak Rate Testing Intervals," dated August 1994.

6. EPRI document "Interim Guidance for Performing Risk Impact Assessments in Support of One-Time Extensions for Containment Integrated Leakage Rate Test Surveillance Intervals," Rev. 4, dated November 2001.

7. EPRI TR-1009325, Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals, Final Report, December 2003.

8. NRC Information Notice 92-20, "Inadequate Local Leak Rate Testing," dated March 3, 1992.

9. Letter from N. Kalyanam, NRC, to J.E. Venable, Entergy Operations Incorporated, "Waterford Steam Electric Station, Unit 3 - Issuance of Amendment RE: Integrated Leakage Rate Testing Interval Extension (TAC No. MB2461)," dated February 14, 2002. (ML020460272).

10. Letter from J. G. Lamb, NRC, to Thomas Coutu, Kewaunee Nuclear Power Plant, "Kewaunee Nuclear Power Plant – Issuance of Amendment (TAC No. MB9907), dated April 6, 2004.

11. Letter from Thomas Coutu, Kewaunee to NRC, License Amendment Request 198 to the Kewaunee Nuclear Power Plant Technical Specifications for One-Time Interval Extension of Containment Integrated Leak Rate Test Interval, dated June 20, 2003.

12. Letter from Thomas Coutu, Kewaunee to NRC, License Amendment Request 198, "ILRT 5-Year Extension," NMC Response to NRC Request for Additional Information, dated December 12, 2003.

13. Letter from J. T. Herron, Waterford 3 SES to NRC, Technical Specification Change Request NPF-38-236 Integrated Leakage Rate Testing Interval Extension, dated July 23, 2001.

14. Letter from J. T. Herron, Waterford 3 SES to NRC, Technical Specification Change Request NPF-38-236 Integrated Leakage Rate Testing Interval Extension, dated September 21, 2001.

15. Letter from J. T. Herron, Waterford 3 SES to NRC, Technical Specification Change Request NPF-38-236 Integrated Leakage Rate Testing Interval Extension, dated November 8, 2001.

Exhibit B

Proposed Technical Specification Changes (markup)

Technical Specification Page

5.0-28

1 page follows

5.5 Programs and Manuals (continued)

5.5.14 Containment Leakage Rate Testing Program

a. A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995, as modified by the following exceptions:

   1. Unit 1 is excepted from post-modification integrated leakage rate testing requirements associated with steam generator replacement.

   2. Exception to NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR 50, Appendix J", Section 9.2.3, to allow the following:

      (i). The first Unit 1 Type A test performed after December 1, 1997 shall be performed by December 1, 2012.

      (ii). The first Unit 2 Type A test performed after March 7, 1997 shall be performed by March 7, 2012.

b. The peak calculated containment internal pressure for the design basis loss of coolant accident is less than the containment internal design pressure, P_a, of 46 psig.

c. The maximum allowable primary containment leakage rate, L_a, at P_a, shall be 0.25% of primary containment air weight per day. For pipes connected to systems that are in the auxiliary building special ventilation zone, the total leakage shall be less than 0.1% of primary containment air weight per day at pressure P_a. For pipes connected to systems that are exterior to both the shield building and the auxiliary building special ventilation zone, the total leakage past isolation valves shall be less than 0.01% of primary containment air weight per day at pressure P_a.

Exhibit C

Proposed Technical Specification Changes (retyped)

Technical Specification Page

5.0-28

1 page follows

5.5 Programs and Manuals (continued)

5.5.14 Containment Leakage Rate Testing Program

a. A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995, as modified by the following exceptions:

   1. Unit 1 is excepted from post-modification integrated leakage rate testing requirements associated with steam generator replacement.

   2. Exception to NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR 50, Appendix J", Section 9.2.3, to allow the following:

      (i). The first Unit 1 Type A test performed after December 1, 1997 shall be performed by December 1, 2012.

      (ii). The first Unit 2 Type A test performed after March 7, 1997 shall be performed by March 7, 2012.

b. The peak calculated containment internal pressure for the design basis loss of coolant accident is less than the containment internal design pressure, P_a, of 46 psig.

c. The maximum allowable primary containment leakage rate, L_a, at P_a, shall be 0.25% of primary containment air weight per day. For pipes connected to systems that are in the auxiliary building special ventilation zone, the total leakage shall be less than 0.1% of primary containment air weight per day at pressure P_a. For pipes connected to systems that are exterior to both the shield building and the auxiliary building special ventilation zone, the total leakage past isolation valves shall be less than 0.01% of primary containment air weight per day at pressure P_a.

Exhibit D

Risk Assessment for Prairie Island Nuclear Generating Plant Regarding ILRT (Type A) Extension Request

116 pages follow

Exhibit D

Risk Assessment for Prairie Island Nuclear Generating Plant Regarding ILRT (Type A) Extension Request

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Appendix A:
Effect of Age-Related Degradation on Risk Impact Assessment for Extending Containment Type A Test Interval A-1

EXECUTIVE SUMMARY

An evaluation was performed to assess the risk impact of extending the currently allowed containment Type A integrated leak rate test (ILRT) frequency from ten years to fifteen years for a one time extension for the Prairie Island Nuclear Generating Plant (PINGP). This would allow for substantial cost savings as the ILRT could be deferred for additional scheduled refueling outages for PINGP. The proposed change would impact testing associated with the current surveillance test for Type A leakage. The risk assessment follows the guidelines from NEI 94-01 [1], the methodology used in EPRI TR-104285 [2], and the NRC regulatory guidance on the use of Probabilistic Risk Assessment (PRA) findings and risk insights in support of a request to change a plant's licensing basis as outlined in Regulatory Guide 1.174 [3]. In addition, for comparison purposes, the risk assessment was also performed using two more recent (although not yet issued in final, approved form) studies. These methodologies are presented in the NEI Interim Guidance [23], and in EPRI TR-1009325 [5]. Although these methodologies generally produce more conservative results than do the earlier methodologies, they build upon the work of the earlier studies, and much of the analyses developed from application of the EPRI TR-104285 methodology remains applicable for use in these more recent studies.

The findings for Prairie Island confirm the general findings of previous studies, namely, that the increased risk to the public due to the extension of the ILRT interval is very low. Factors considered in the risk analysis were the plant-specific severe accident category frequencies, the containment failure modes, the Technical Specification allowed leakage, and the local population surrounding the Prairie Island station. Based on the results from Sections 5 through 7, the following conclusions regarding the assessment of the plant risk are associated with extending the Type A ILRT test from ten years to fifteen years:

- There is no change in the at-power CDF associated with the ILRT test interval extension. Therefore, this is within the Reg. Guide 1.174 acceptance guidelines.

- Reg. Guide 1.174 provides guidance for determining the risk impact of plant-specific changes to the licensing basis. Reg. Guide 1.174 defines very small changes in risk as resulting in increases of CDF below 10^{-6}/yr and increases in LERF below 10^{-7}/yr. Since the ILRT does not impact CDF, the relevant criterion is LERF. The increase in LERF resulting from a change in the Type A ILRT test frequency from once-per-ten-years to once-per-fifteen years is between 5.33E-9/yr [7.46E-9/yr] and 5.93E-08/yr [8.30E-8/yr]. Therefore, increasing the ILRT interval from 10 to 15 years is considered to result in a very small change to the Prairie Island risk profile.

- The proposed change in the Type A test frequency (from once-per-ten-years to once-per-fifteen-years) increases the total integrated plant risk by significantly less than 1% for both units. Therefore, the risk impact of this change, when compared to other severe accident risks, is negligible.

- The change in Conditional Containment Failure Probability (CCFP) of less than 1% for both units is judged to be insignificant and reflects sufficient defense-in-depth.

Section 1
PURPOSE OF ANALYSIS

The purpose of this analysis is to provide a risk assessment of extending the currently allowed containment Type A integrated leak rate test (ILRT) frequency extension from ten years to fifteen years for Prairie Island. The extension would allow for substantial cost savings as the ILRT could be deferred for additional scheduled refueling outages for Prairie Island. The proposed change would impact testing associated with the current program procedure H19, "Containment Leak Rate Testing [24]."

The risk assessment follows the guidelines from NEI 94-01 [1], the methodology used in EPRI TR-104285 [2], and the NRC regulatory guidance on the use of Probabilistic Risk Assessment (PRA) findings and risk insights in support of a request to change a plant's licensing basis as outlined in Regulatory Guide 1.174 [3]. In addition, for comparison purposes, the risk assessment was also performed using two more recent (although not yet issued in final, approved form) studies. These methodologies are presented in the NEI Interim Guidance [23], and in EPRI TR-1009325 [5]. Although these methodologies generally produce more conservative results than do the earlier methodologies, they build upon the work of the earlier studies, and much of the analyses developed from application of the EPRI TR-104285 methodology remains applicable for use in these more recent studies. Therefore, the calculations and results from these analyses are presented at the end of this report (Sections 6 and 7), with references to the previous EPRI TR-104285 results provided as necessary for efficient reporting of the study results.

Note that where results are presented in the body of the text, the Unit 1 results are presented first, followed by the Unit 2 results in brackets (for example: 4.0E-05/yr [6.0E-5/yr]).

1.1 BACKGROUND

10CFR50, Appendix J, Option B, allows individual plants to extend the Type A Integrated Leak Rate Test (ILRT) surveillance test interval from three-in-ten years to at least once per ten years. The revised Type A frequency is based on an acceptable performance history defined as two consecutive periodic Type A tests at least 24 months apart in which the calculated leakage performance was less than 1.0La. Prairie Island meets these requirements.

The basis for the current 10-year test interval is provided in Section 11.0 of NEI 94-01, Revision 0, and was established in 1995 during development of the performance-based Option B to Appendix J. Section 11.0 of NEI 94-01 states that NUREG-1493, "Performance-Based Containment Leak Test Program," September 1995, provides the technical basis to support rule making to revise leakage rate testing requirements contained in Option B to Appendix J. The basis consisted of qualitative and quantitative assessments of the risk impact (in terms of increased public dose) associated with a range of extended leakage rate test intervals. To supplement the NRC's rule making basis, NEI undertook a similar study. The results of that study are documented in Electric Power Research Institute (EPRI) Research Project Report TR-104285 [2].

The NRC report, Performance Based Leak Test Program, NUREG-1493 [4], which analyzed the effects of containment leakage on the health and safety of the public and the benefits realized from the containment leak rate testing determined that increasing the containment leak rate from the nominal 1.0 percent per day to 10 percent per day leads to a small increase in total population exposure. In addition, increasing the leak rate to 100 percent per day increases the total population risk by less than 1 percent. Consequently, extending the ILRT interval should not lead to any substantial increase in risk: The current analysis is being performed to confirm these conclusions based on Prairie Island specific models and available data.

EPRI TR-104285 (Risk Impact Assessment of Revised Containment Leak Rate Testing Intervals) is a follow-on report to NUREG-1493 that provides a methodology for use in preparing PRA analysis to support a submittal. This methodology is followed to determine the appropriate risk information for use in evaluating the impact of the proposed ILRT changes.

It should be noted that containment leak-tight integrity is also verified through periodic in-service inspections conducted in accordance with the requirements of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), Section XI. More specifically, Subsection IWE provides the rules and requirements for in-service inspection of Class MC pressure-retaining components and their integral attachments, and of metallic shell and penetration liners of Class CC pressure-retaining components and their integral attachments in light-water cooled plants. Furthermore, NRC regulations 10 CFR 50.55a(b)(2)(ix)(E), require licensees to conduct a general visual inspection of the accessible areas of the interior of the containment in accordance with Subsection IWE once each period. These requirements will not be changed as a result of the extended ILRT interval. In addition, Appendix J, Type B and Type C local leak tests performed to verify the leak-tight integrity of containment penetration valves, air locks, seals, and gaskets are also not affected by the change to the Type A test frequency.

1.2 CRITERIA

The acceptance guidelines in RG 1.174 are used to access the acceptability of this one-time extension of the Type A test interval beyond that established during the Option B rulemaking of Appendix J. RG 1.174 defines very small changes in the risk-acceptance guidelines as increases in core damage frequency (CDF) less than 10^{-6} per reactor year and increases in large early release frequency (LERF) less than 10^{-7} per reactor year. Since the Type A test does not impact

CDF, the relevant criterion is the change in LERF. RG 1.174 also discusses defense-in-depth and encourages the use of risk analysis techniques to help ensure and show that key principles, such as the defense-in-depth philosophy, are met. Therefore, the increase in the conditional containment failure probability which helps to ensure that the defense-in-depth philosophy is maintained will also be calculated.

In addition, the total risk (person rem/yr population dose) is examined to demonstrate the relative change in this parameter.

Section 2
METHODOLOGY

A simplified bounding analysis approach consistent with the EPRI approach is used for evaluating the change in risk associated with increasing the test interval to fifteen years. The approach is consistent with that presented in EPRI TR-104285 [2] and NUREG-1493 [4]. The analysis uses the current Prairie Island Probabilistic Risk Assessment (PRA) model that includes the results from the Prairie Island Level 2 analysis of core damage scenarios and subsequent containment response resulting in various fission product release categories (including no release).

The four general steps of this risk assessment are as follows:

1) Quantify the baseline risk in terms of frequency events (per reactor year) for each of the eight containment release scenario types identified in the EPRI report.

2) Apply NUREG-1150 offsite consequence measures based on population dose (person-rem) per reactor year for each of the eight containment release scenario types from consequence analyses (i.e., previously performed calculations using MACCS for the "reference plant" PWR, as documented in EPRI TR-104285).

3) Evaluate the risk impact (i.e., the change in containment release scenario type frequency and population dose) of extending the ILRT interval to fifteen years.

4) Determine the change in risk in terms of Large Early Release Frequency. (LERF) in accordance with Regulatory Guide 1.174 [3] and compare with the acceptance guidelines of RG 1.174.

This approach is based on the information and methodology contained in the previously mentioned studies and further is consistent with the following:

- Other industry risk assessments for ILRT test interval extensions. The Prairie Island assessment uses population dose as one of the risk measures. The other risk measures used in the Prairie Island assessment are Large Early Release Frequency (LERF), and Conditional Containment Failure Probability (CCFP) to demonstrate that the acceptance guidelines from RG 1.174 are met.

- EPRI TR-104285 and NUREG-1493. The Prairie Island assessment uses information from NUREG-1273 [6] regarding the low percentage of containment leakage events that would only be detected by an ILRT as input to calculate the increase in the pre-existing containment leakage probability due to the testing interval extension.

- The approach used in the Indian Point 3 risk-informed submittal for a one-time extension of the Type A test interval. The Prairie Island evaluation uses similar ground rules and methods to calculate changes in risk metrics [14]. NRC approval was granted Indian Point 3 on April 17, 2001 (TAC No. MB0178) [21].

Section 3
GROUND RULES

This section summarizes the general rules used in the ILRT interval extension risk analysis (Section 3.1) and provides details regarding the capabilities of the PRA model that was used in the analysis (Section 3.2).

3.1 GROUND RULES

The following ground rules are used in the analysis:

- The Prairie Island Level 1 and Level 2 internal events PRA model provides representative results for the analysis. The Prairie Island Level 1 models include internal flooding events. Section 3.2 below provides details regarding the scope and capabilities of the Prairie Island PRA model.

- It is appropriate to use the Prairie Island internal events PRA model as a gauge to effectively describe the risk changes attributable to the ILRT extension. It is reasonable to assume that the impact from the ILRT extension (with respect to percent increases in population dose) will not substantially differ if fire and shutdown events were to be included in the calculations. Section 3.2 below provides additional details relative to the appropriateness of the application of Prairie Island internal events models to the ILRT extension risk analysis.

- An evaluation of the risk trade-off impact of performing the ILRT during shutdown is addressed using the generic results from EPRI TR 105189 [10].

- Prairie Island population doses for the containment failures modeled in the PRA can be characterized by the NUREG-1150 (PWR "reference plant") population dose results from MACCS calculations presented in EPRI TR-

104285 [2].

- Accident classes describing radionuclide release end states are defined consistent with EPRI methodology [2] and are summarized in Section 4.2.

- The maximum containment leakage for Class 1 sequences is 1.0 L_a. Class 3 accounts for increased leakage due to Type A inspection failures.

- The maximum containment leakage for Class 3a sequences is 10 L_a. based on the previously approved methodology [14, 21].

- The maximum containment for Class 3b sequences is 35 L_a. based on the previously approved methodology [14, 21].

- The impact on population doses from Interfacing System LOCAs is not altered by the proposed ILRT extension, but is accounted for in the EPRI methodology as a separate entry for comparison purposes. Since the ISLOCA contribution to population dose is fixed, no changes on the conclusions from this analysis will result from this assumption.

- The reduction in ILRT frequency does not impact the reliability of containment isolation valves to close in response to a containment isolation signal. Containment isolation valves that fail to close during an accident and in response to a containment isolation signal are calculated on a Prairie Island specific basis and made part of the overall population dose and LERF calculations.

3.2 PRA MODEL CAPABILITIES AND APPROPRIATENESS FOR APPLICATION

Risk-informed support for the proposed ILRT interval changes is based in part upon analyses that include results from the Prairie Island Level 1 and Level 2 Probabilistic

Risk Assessment (PRA) models. The scope, level of detail, and quality of the Prairie Island PRA is sufficient to support a technically defensible and realistic evaluation of the risk change for the proposed ILRT interval extension.

The Prairie Island PRA is an upgrade to the Individual Plant Examination (IPE) submitted to the NRC by letter dated March 1, 1994. The NRC accepted the IPE by letter dated May 16, 1997. The NRC letters noted that the IPE submittals met the intent of Generic Letter 88-20, "Individual Plant Examination for Severe Accident Vulnerabilities – 10CFR 50.54(f)", dated November 23, 1988.

A brief summary of the recently upgraded Prairie Island PRA is provided in Exhibit E of this LAR submittal. In addition to incorporating recent advances in PRA technology across all elements of the PRA, a special effort was made to ensure that elements of the PRA are adequate to evaluate the risk impacts of the extended ILRT intervals. These elements include the proper characterization of containment bypass sequences, containment isolation failures, and containment release categories that do not involve containment failure ("leakage only" release categories). An "extension" of the current internal events PRA model was performed to update these elements of the existing Level 2 analysis, specifically for this LAR.

A portion of the risk analysis involves comparison of the plant Large, Early Release Frequency (LERF) from the baseline case (ILRTs assumed to be performed on the existing intervals) with various cases in which the ILRT intervals have been extended. For the baseline analysis, LERF was estimated using the methodologies in NUREG/CR-6595, January 1999, "An Approach for Estimating the Frequencies of Various Containment Failure Modes and Bypass Events." This approach to LERF evaluation, while somewhat simplified, supports realistic quantification of systematic contributions to containment isolation failures, bypass sequences that are actually derived from the Level 1 sequences model, and conservative evaluation of severe accident challenges which are less important for PWRs with large, dry containments. This methodology was also used for the ILRT interval extension cases, except that the portion of the LERF attributable to the extension was also added to the results, according to the various methodologies used (as outlined in Sections 4 – 7 in this report).

Peer review certification of the Prairie Island PRA model using the Westinghouse Owners Group (WOG) Peer Review Certification Guidelines was performed during the week of September 25, 2000. A team of independent PRA experts from nuclear utility groups and PRA consulting organizations carried out this Peer Review Certification. This intensive peer review involved about two person-months of engineering effort by the review team and provided a comprehensive assessment of the strengths and limitations of each element of the PRA model. All of the findings and observations from this assessment that were considered important by the review team and that are needed to evaluate the proposed ILRT interval extension have been dispositioned. The Peer Review Certification of the Prairie Island PRA model performed by the WOG resulted in five Findings and Observations (F&O) with the significance level of "A" and 32 F&O with a significance level of "B". This resulted in a number of enhancements to the PRA model prior to its use to support these proposed changes. A summary of the significance level A and B F&Os and their corresponding resolutions can be found in Exhibit F of this LAR submittal.

The certification team determined that with these proposed changes incorporated, the quality of all elements of the PRA model are of sufficient quality that "supports risk significant evaluations with deterministic input." As a result of the effort to incorporate the latest industry insights into the PRA model upgrades and certification peer reviews, NMC concluded that the risk evaluation are technically sound and consistent with the expectations for PRA quality set forth in RG 1.174 and RG 1.177.

Section 4

INPUTS

This section summarizes the general resources available as input (Section 4.1) and the plant specific resources required (Section 4.2).

4.1 GENERAL RESOURCES AVAILABLE

Various industry studies on containment leakage risk assessment are briefly summarized here:

1) NUREG/CR-3539 [7]
2) NUREG/CR-4220 [8]
3) NUREG-1273 [6]
4) NUREG/CR-4330 [9]
5) EPRI TR-105189 [10]
6) NUREG-1493 [4]
7) EPRI TR-104285 [2]

The first study is applicable because it provides one basis for the threshold that could be used in the Level 2 PSA for the size of containment leakage that is considered significant and to be included in the model. The second study is applicable because it provides a basis of the probability for significant pre-existing containment leakage at the time of a core damage accident. The third study is applicable because it is a subsequent study to NUREG/CR-4220 which undertook a more extensive evaluation of the same database. The fourth study provides an assessment of the impact of different containment leakage rates on plant risk. The fifth study provides an assessment of the impact on shutdown risk from ILRT test interval extension. The sixth study is the NRC's cost-benefit analysis of various alternative approaches regarding extending the test intervals and increasing the allowable leakage rates for containment integrated and local leak rate tests. The last study is an EPRI study of the impact of extending ILRT and LLRT test intervals on at-power public risk.

NUREG/CR-3539 [7]

Oak Ridge National Laboratory documented a study of the impact of containment leak rates on public risk in NUREG/CR-3539. This study uses information from WASH-1400 as the basis for its risk sensitivity calculations. ORNL concluded that the impact of leakage rates on LWR accident risks is relatively small.

NUREG/CR-4220 [8]

NUREG/CR-4220 is a study performed by Pacific Northwest Laboratories for the NRC in 1985. The study reviewed over two thousand LERs, ILRT reports and other related records to calculate the unavailability of containment due to leakage. The study calculated unavailabilities for Technical Specification leakages and "large" leakages. It is the latter category that is applicable to containment isolation modeling that is the focus of this risk assessment.

NUREG/CR-4220 assessed the "large" containment leak probability to be in the range of 1E-3 to 1E-2, with 5E-3 identified as the point estimate based on 4 events in 740 reactor years and conservatively assuming a one-year duration for each event. It should be noted that all of the 4 identified large leakage events were PWR events.

NUREG-1273 [6]

A subsequent NRC study, NUREG-1273, performed a more extensive evaluation of the NUREG/CR-4220 database. This assessment noted that about one-third of the reported events were leakages that were immediately detected and corrected. In addition, this study noted that local leak rate tests can detect "essentially all potential degradations" of the containment isolation system.

NUREG/CR4330 [9]

NUREG/CR-4330 is a study that examined the risk impacts associated with increasing the allowable containment leakage rates. The details of this report have no direct impact on the modeling approach of the ILRT test interval extension, as NUREG/CR-4330 focuses on leakage rate and the ILRT test interval extension study focuses on the frequency of testing intervals. However, the general conclusions of NUREG/CR-4330 are consistent with NUREG/CR-3539 and other similar containment leakage risk studies:

> "...the effect of containment leakage on overall accident risk is small since risk is dominated by accident sequences that result in failure or bypass of containment."

EPRI TR-105189 [10]

The EPRI study TR-105189 is useful to the ILRT test interval extension risk assessment because this EPRI study provides insight regarding the impact of containment testing on shutdown risk. This study performed a quantitative evaluation (using the EPRI ORAM software) for two reference plants (a BWR-4 and a PWR) of the impact of extending ILRT and LLRT test intervals on shutdown risk.

The result of the study concluded that a small but measurable safety benefit is realized from extending the test intervals. For the benefit from extending the ILRT frequency from 3 per 10 years was calculated to be a reduction of approximately 1E-7/yr in the shutdown core damage frequency. This risk reduction is due to the following issues:

- Reduced opportunity for drain down events
- Reduced time spent in configurations with impaired mitigating systems

The study identified 7 shutdown incidents (out of 463 reviewed) that were caused by ILRT or LLRT activities. Two of the 7 incidents were RCS-draindown events caused by ILRT/LLRT activities, and the other 5 were events involving loss of RHR and/or SDC due to ILRT/LLRT activities. This information was used in the EPRI study to estimate the safety benefit from reductions in testing frequencies. This represents a valuable insight into the improvement in safety due to extending the ILRT test interval.

NUREG-1493 [4]

NUREG-1493 is the NRC's cost-benefit analysis for proposed alternatives to reduce containment leakage testing intervals and/or relax allowable leakage rates. The NRC conclusions are consistent with other similar containment leakage risk studies:

- Reduction in ILRT frequency from 3 per 10 years to 1 per 20 years results in an "imperceptible" increase in risk.
- Increasing containment leak rates several orders of magnitude over the design basis would minimally impact (0.2-1.0%) population risk.

NUREG-1493 used information from NUREG-1273 regarding the low percentage of containment leakage events that would only be detected by an ILRT in the calculation of the increase in the pre-existing containment leakage probability due to the testing interval extension. NUREG-1493 makes the following assumptions in this probability calculation:

- The average time that a pre-existing leakage may go undetected increases with the length of the testing interval (and is ½ the length of the test interval).
- Only 3% of all pre-existing leaks can be detected only by an ILRT (i.e., and not by LLRTs).

This same approach that was used in a previously approved ILRT test interval extension submittal [14, 21] is also proposed here for the Prairie Island ILRT test interval extension risk assessment.

<u>EPRI TR-104285 [2]</u>

Extending the risk assessment impact beyond shutdown (the earlier EPRI TR-105189 study), the EPRI TR-104285 study is a quantitative evaluation of the impact of extending ILRT and LLRT test intervals on at-power public risk. This study combined IPE Level 2 models with NUREG-1150 Level 3 population dose models to perform the analysis. The study also used the approach of NUREG-1493 in calculating the increase in pre-existing leakage probability due to extending the ILRT and LLRT test intervals.

EPRI TR-104285 used a simplified Containment Event Tree to subdivide representative core damage frequencies into eight (8) classes of containment response to a core damage accident:

1. Containment intact and isolated
2. Containment isolation failures dependent upon the core damage accident
3. Type A (ILRT) related containment isolation failures
4. Type B (LLRT) related containment isolation failures
5. Type C (LLRT) related containment isolation failures
6. Containment isolation failures not identified by LLRT (e.g., isolation failures due to testing or maintenance)
7. Containment failure due to core damage accident phenomena
8. Containment bypass

Consistent with the other containment leakage risk assessment studies, this study concluded:

> "These study results show that the proposed CLRT [containment leak rate tests] frequently changes would have a minimal safety

impact. The change in risk determined by the analyses is small in both absolute and relative terms. For example, for the PWR analyzed, the change is about 0.02 person-rem per year..."

4.2 CALCULATION OF SPECIFIC INPUTS

The information used to perform the Prairie Island ILRT Extension Risk Assessment includes the following:

- Population dose calculations by release category (e.g., based on MACCS code calculation results for NUREG-1150 plants as documented in EPRI TR-104285).
- Prairie Island PRA Model
- ILRT results to demonstrate adequacy of the administrative and hardware issues. The two most recent Type A ILRT tests for Prairie Island were successful, so the current Type A test interval is 10 years.

<u>Release Category Definition</u>

Table 4.2-1 defines the accident classes used in the ILRT extension evaluation consistent with the EPRI methodology [2].

Table 4.2-1

EPRI CONTAINMENT FAILURE CLASSIFICATIONS

Class	Description
1	Includes accident sequences that do not lead to containment failure in the long term (containment remains intact). The release of fission products (and attendant consequences) is determined by the maximum allowable leakage rate values La, under Appendix J for that plant.
2	Includes those accidents in which there is a failure to isolate the containment (containment isolation failures).
3	Includes those accidents in which the pre-existing isolation failure to seal (i.e., provide a leak-tight containment) is not dependent on the sequence in progress (independent, or random, isolation failures).
4	Includes those accidents in which the pre-existing isolation failure to seal is not dependent on the sequence in progress (independent, or random, isolation failures). This class is similar to Class 3 isolation failures, but is applicable to sequences involving Type B tests. These are the Type B-tested components that have isolated but exhibit excessive leakage.
5	Includes those accidents in which the pre-existing isolation failure to seal is not dependent on the sequence in progress (independent, or random, isolation failures). This class is similar to Class 4 isolation failures, but is applicable to sequences involving Type C tests and their potential failures.
6	Includes those leak paths (containment isolation failures) covered in the plant test and Maintenance requirements or verified per in service inspection and testing (ISI/IST).
7	Accidents involving containment failure induced by severe accident phenomena. Changes in Appendix J testing requirements do not impact these accidents.
8	Accidents in which the containment is bypassed (either as an initial condition or induced by phenomena) are included in Class 8. Changes in Appendix J testing requirements do not impact these accidents.

Population Dose Calculations

As consequence measures (population doses) from Level 3 PRA analysis are not available for Prairie Island, the population doses applied to the various release categories identified in Section 4.1 are taken from data presented for a PWR "representative plant" in EPRI TR-104285, Table 4. The representative plant data used estimated release fractions of fission product species reported in IPE analyses for the various release categories, and applied population doses to these categories based on MACCS calculations performed for Surry in NUREG-1150 [22]. Table 4.2-2 summarizes the calculated population doses for each release category defined in the EPRI report.

As stated in EPRI TR-104285, there are a number of parameters that determine the offsite calculations for similar source term release magnitudes, including the power rating and demographics of the Surry plant as compared to the representative plants (and to Prairie Island). However, the EPRI TR-104285 "representative plant" methodology is acceptable for use for plants without plant-specific Level 3 consequence measures, including Prairie Island, since the comparison is made to a baseline. Therefore, the differences in the above parameters not considered in this analysis would not impact the conclusions drawn. This is demonstrated for the Prairie Island results in Section 8.3 below.

A summary of the population dose measures applied to all accident classes except Class 3 is provided in Table 4.2-2 below. The population dose for Class 3 is developed in Section 5.2 of this report.

Table 4.2-2

SUMMARY OF ACCIDENT CLASS CONSEQUENCE MEASURES (POPULATION DOSE) BASED ON EPRI TR-104285 [2], TABLE 4

Release Category	Description	Population Dose for Entire Region (person-rem)[1]
1	Intact Containment	8.97E+01
2	Loss of Containment Isolation	4.07E+06
3	Type A (ILRT) related containment isolation failures	[Calculated based on EPRI Methodology – see Section 5.2]
4	Type B (LLRT) related containment isolation failures	n/a to ILRT extension
5	Type C (LLRT) related containment isolation failures	n/a to ILRT extension
6	Containment isolation failures not identified by LLRT	n/a to ILRT extension
7	Containment failure due to core damage accident phenomena	2.16E+06
8	Containment bypass	1.24E+07

Note 1: EPRI TR-104285, Table 4 provides frequencies (per Rx-yr) and consequence measures (person-rem/yr) by accident class. Dose (person-rem) is determined from the table by dividing the consequence measure by the accident class frequency.

Prairie Island PRA Model

The most recent revision to the Prairie Island internal events PRA Model (Revision 2.1) was used to quantify frequencies for accident classes (release categories) used in the EPRI TR-104285 methodology (see Reference 26). A summary of these calculation results is provided in Table 4.2-3. For Revision 2.1 of the Prairie Island PRA model, the Core Damage Frequency (CDF) is 1.61E-5 per-yr [2.16E-5 per-yr] and the Large Early Release Frequency (LERF) is 5.74E-07 per-yr [5.75E-07 per-yr].

Table 4.2-3

SUMMARY OF EPRI TR-104285 ACCIDENT CLASS FREQUENCIES CALCULATED WITH REVISION 2.1 OF THE PRAIRIE ISLAND PRA MODEL

EPRI Accident Class	Description	Rev. 2.1 PRA Category[1]	Frequency (per rx-year)	
			Unit 1	Unit 2
1	Intact Containment	X-XX-X L-XX-X H-XX-X[2]	1.30E-05	1.81E-05
2	Containment Isolation Failure	CDFNOCI[3]	2.31E-09	3.15E-09
3	Type A (ILRT) related containment isolation failures	[calculated based on EPRI Methodology –see Sec. 5.1]	N/A	N/A
4	Type B (LLRT) related containment isolation failures	[n/a for ILRT interval extensions]	N/A	N/A
5	Type C (LLRT) related containment isolation failures	[n/a for ILRT interval extensions]	N/A	N/A
6	Containment isolation failures not identified by LLRT	[n/a for ILRT interval extensions]	N/A	N/A
7	Containment failure due to core damage accident phenomena	[Overall CDF – all other Release Categories]	4.38E-07	8.27E-07
8	Containment bypass	GEH GLH ISLOCA[4]	2.68E-06	2.68E-06
Total			**1.61E-05**	**2.16E-05**

[1]PRA "Categories" are made up of Level 2 release categories, Level 1 accident classes, and other metrics quantified to determine the total frequency of each EPRI accident class.
[2] Level 2 release categories X-XX-X, L-XX-X and H-XX-X are "no containment failure" end states in which the first letter indicates the RCS pressure at the time of reactor vessel failure (X = no vessel failure, L = vessel failure at low pressure, and H = vessel failure at high pressure)
[3]PRA "Category" CDFNOCI is a Rev. 2.1 model fault tree gate (1CDFNOCI for Unit 1, 2CDFNOCI for Unit 2) quantified separately to determine the
[4]PRA "Categories" are made up of Level 1 accident classes involving SGTR sequences (GEH, GLH) and Intersystem LOCA sequences (ISLOCA) which are assumed to effectively bypass containment.

4.3 CONDITIONAL PROBABILITY OF ILRT FAILURE (SMALL AND LARGE)

The ILRT can detect a number of failures such as liner breach, failure of certain bellows arrangements, and failure of some sealing surfaces. The proposed ILRT test interval extension may influence the conditional probability associated with the ILRT failure. To ensure that this effect is properly accounted for, the Class 3 accident class is divided into two sub-classes, Class 3a and Class 3b, representing small and large leakage failures, respectively.

To calculate the probability that a liner leak will be large (event Class 3b), use was made of the data presented in NUREG-1493 [4]. The data found in NUREG-1493 states that 144 ILRTs were conducted. The largest reported leak rate from those 144 tests was 21 times the allowable leakage rate (L_a). Because $21L_a$ does not constitute a large release, no releases have occurred based on the 144 ILRTs reported in NUREG-1493 [4].

To estimate the failure probability given that no failures have occurred, a conservative estimate is obtained from the 95th percentile of the χ^2 distribution. In statistical theory, the χ^2 distribution can be used for statistical testing, goodness-of-fit tests, and evaluating s-confidence [25]. The χ^2 distribution is really a family of distributions, which range in shape from that of the exponential to that of the normal distribution. Each distribution is identified by the degrees of freedom, ν. For time-truncated tests (versus failure-truncated tests), an estimate of the probability of a large leak using the χ^2 distribution can be calculated as χ^2_{95} (ν = 2n + 2) / 2N, where n represents the number of large leaks and N represents the number of ILRTs performed to date. With no large leaks (n = 0) in 144 events (N = 144) and χ^2_{95} (2) = 5.99, the 95th percentile estimate of the probability of a large leak is calculated as 5.99 / (2 * 144) = 0.021.

To calculate the probability that a liner leak will be small (event Class 3a), use was made of the data presented in NUREG-1493 [4]. The data found in NUREG-1493 states that 144 ILRTs were conducted. The data reported that 23 of 144 tests had allowable leak rates in excess of $1.0L_a$. However, of these "failures" only 4 were found by an ILRT; the others were found by Type B and C testing on errors in test alignments. Therefore, the number of failures considered for "small releases" are 4-of-144. Similar to the event Class 3b probability, the estimated failure probability for small release is found by using the χ^2 distribution. The χ^2 distribution is calculated by n = 4 (number of small leaks) and N = 144 (number of events) which yields a. $\chi^2_{95}(10) = 18.3070$. Therefore, the 95th percentile estimate of the probability of a small leak is calculated as 18.3070 / (2 * 144) = 0.064.

Using the methodology discussed above is conservative compared to the typical mean estimates used for PRA analysis. For example, the mean probability of a Class 3a failure would be the (number of failures) / (number of tests) or 4/144 = 0.03 compared with 0.064 used here.

4.4 IMPACT OF EXTENSION ON LEAK DETECTION PROBABILITY

The NRC in NUREG-1493 [4] has determined from a review of operating experience data that only 3% of the ILRT failures were found which local leakage-rate testing could not and did not detect. In NUREG-1493 [4], it is noted that based on a review of leak rate testing experience, a small percentage (3% of leakages that exceed current requirements are detectable only by Type A testing). Further, in NUREG-1493 it is noted that the leakage rates observed in these few Type A test failures were only marginally above currently prescribed limits and could be characterized by a leakage rate of about two times the allowable.

Also in NUREG-1493 [4], it was assumed that the characteristic magnitude of leakages detectable only by ILRTs would not change, but the probability of leakage would change due to the longer intervals between tests. The change in probability was estimated by comparing the average time that a leak could exist without detection. For example, the average time that a leak could go undetected with a three-year test interval is 1.5 years (3yrs/2), and the average time that a leak could exist without detection for a ten-year interval is 5 years (10yrs/2). This change would lead to a non-detection probability that is a factor of 3.33 (5.0/1.5) higher for the probability of a leak that is detectable only by ILRT testing. However, since ILRTs have been demonstrated to improve the residual leak detection by only 3%, the interval change noted above would only lead to about a 10% (3.33 x 3%) non-detection leak probability. It is assumed that Local Leak Rate Test (LLRT) will continue to provide leak detection for the 97% of leakages. Correspondingly, an extension of the ILRT interval to fifteen years can be estimated to lead to about a 15% (7.5/1.5x3%) non-detection probability of a leak. These are obviously approximations assumed by the NRC and EPRI because the current 3 ILRTs in 10 years would have a T/2 = 1.67 years instead of 1.5 years.

Therefore, the failure rate of ILRTs for which the LLRTs do not provide adequate backup is 0.03/1.5 year average detection time. Applying a constant failure rate model, the failure probability of ILRTs, P_f, can be estimated as follows:

<u>For 3 Year Interval</u>

$$P_f = \frac{1}{2}\lambda T = \left(\frac{.03}{1.5yr}\right)\left(\frac{3yr}{2}\right) = 0.03$$

<u>For 10 Year Interval</u>

$$P_f = \frac{1}{2}\lambda T = \left(\frac{.03}{1.5yr}\right)\left(\frac{10yr}{2}\right) = 0.10$$

<u>For 15 Year Interval</u>

$$P_f = \frac{1}{2}\lambda T = \left(\frac{.03}{1.5yr}\right)\left(\frac{15yr}{2}\right) = 0.15$$

EPRI has previously interpreted this to mean that the failure to detect probability values are tabulated as follows:

Table 4.2-4

ILRT FAILURE TO DETECT PROBABILITY

ILRT Interval	EPRI Assessment [2]	IP3 [14]	Constant Failure Rate Model
3 yr	0.03	0.03	0.03
10 yr	0.13	0.13	0.10
15 yr	NA	0.18	0.15

In addition, IP3 [14] has used this same estimate of changes in detection probability in a submittal to extend the ILRT interval on a one-time basis. The IP3 request for a one-time ILRT extension was approved by the NRC on April 17, 2000 (TAC No. MB0178) [21].

The analysis included in this report follows the precedence set by the EPRI report and the IP3 analysis. The use of the constant failure rate model is conservatively represented by the assumed "failure to detect" probabilities used by EPRI and in the IP3 submittal.

Section 5
RESULTS

The application of the approach based on EPRI-TR-105189 [10] and previous risk assessment submittals on this subject [14] has established a clear process for the calculation and presentation of results.

The method chosen to display the results is according to the eight (8) accident classes consistent with these two reports. Table 5-1 lists these accident classes.

The analysis performed examined Prairie Island specific accident sequences in which the containment remains intact or the containment is impaired. Specifically, the break down of the severe accident contribution to risk was considered in the following manner:

- Core damage sequences in which the containment remains intact initially and in the long term (EPRI TR-104285 Class 1 sequences).

- Core damage sequences in which containment integrity is impaired due to random isolation failures of plant components other than those associated with Type B or Type C test components. For example, liner breach or bellows leakage. (EPRI TR-104285 Class 3 sequences).

- Core damage sequences in which containment integrity is impaired due to containment isolation failures of pathways left "opened" following a plant post-maintenance test. (For example, a valve failing to close following a valve stroke test - EPRI TR-104285 Class 6 sequences).

- Accident sequences involving containment bypass (EPRI TR-104285 Class 8 sequences), large containment isolation failures (EPRI TR-104285 Class 2 sequences), and small containment isolation "failure-to-seal" events (EPRI TR-104285 Class 4 and 5 sequences) are accounted for in this evaluation as part of the baseline risk profile. However, they are not affected by the ILRT frequency change.

- Class 4 and 5 sequences are impacted by changes in Type B and C test intervals; therefore, changes in the Type A test interval do not impact these sequences.

Table 5-1

ACCIDENT CLASSES

Accident Classes (Containment Release Type)	Description
1	No Containment Failure
2	Large Isolation Failures (Failure to Close)
3a	Small Isolation Failures (liner breach)
3b	Large Isolation Failures (liner breach)
4	Small Isolation Failures (Failure to seal-Type B)
5	Small Isolation Failures (Failure to seal-Type C)
6	Other Isolation Failures (e.g., dependent failures)
7	Failures Induced by Phenomena (Early and Late)
8	Bypass (Interfacing System LOCA)
CDF	All CET End states (including very low and no release)

The steps taken to perform this risk assessment evaluation are as follows:

Step 1 - Quantify the base-line risk in terms of frequency per reactor year for each of the applicable eight accident classes presented in Table 5-1.

Step 2 - Develop plant specific person-rem dose (population dose) per reactor year for each of the eight accident classes evaluated in EPRI TR-104285.

Step 3 - Evaluate the risk impact of extending Type A test interval from 10 to 15 years.

Step 4 - Determine the change in risk in terms of Large Early Release Frequency (LERF) in accordance with RG 1.174.

5.1 STEP 1 - QUANTIFY THE BASE-LINE RISK IN TERMS OF FREQUENCY PER REACTOR YEAR

The severe accident sequence frequencies that can result in offsite consequences were evaluated. Revision 2.1 of the Prairie Island PRA model as documented by NMC was used in the ILRT evaluation. In a separate PRA calculation [26], containment non-leakage release categories (identified in Table 4.2-3) were quantified based on this recent update (Rev. 2.1) of the PRA.

The mapping of EPRI accident classes to population dose for the region around the Prairie Island plant was discussed in Section 4.2 above. The results of this mapping are provided on Table 4.2-3.

The extension of the Type A test interval does not influence those accident progressions that involve containment isolation failures, Type B or Type C testing, or containment failure induced by severe accident phenomena.

For the assessment of ILRT impacts on the risk profile, the potential for pre-existing leaks are included in the model. Specifically, a simplified model based on NUREG-1493 results is used to predict the likelihood of having a small/large breach in the containment liner that is undetected by the Type A ILRT test.

These events are represented by the "Class 3" sequence depicted in EPRI TR-104285 [2]. The Class 3 leakage includes the probability of a liner breach or bellows failure (due to excessive leakage) at the time of core damage. Two failure modes, event Class 3a (small breach) and event Class 3b (large breach) were considered to ensure proper representation of available data.

After including the respective "large" and "small" liner breach leak rate probabilities (Classes 3a and 3b), the eight severe accidents class frequencies were developed consistent with the definitions in Table 5-1 and described below.

Class 1 Sequences.

This group consists of all core damage accident progression bins for which the containment remains intact (modeled as Technical Specification Leakage). The frequency per year for these sequences is 1.30E-5/year [1.81E-5/year] from the quantification using the Rev. 2.1 model described above. However, note that Class 3, described below, is not calculated from the PRA model but is considered to apply only to Class 1-type sequences. Therefore, a portion of the Class 1 sequence total were applied to Class 3 below – as such, the final Class 1 frequency to which Class 1 consequence measures will be applied is determined by subtracting all other containment failure end states from the total CDF, effectively the Class 1 calculated value less the Class 3 sequence total.
After all containment failure accident class frequencies (Classes 2 through 8) were developed, frequencies for Classes 2 through 8 were summed (result = 4.5E-6/yr [5.3E-6/yr]). This was then subtracted from the total CDF (1.61E-5/yr [2.16E-5/yr]) to obtain the Class 1 frequency of "No Containment Failure" of 1.16E-5/yr [1.63E-5/yr]. For this analysis, the associated maximum containment leakage for this group is $1.0L_a$, consistent with an intact containment evaluation.

Class 2 Sequences.

This group consists of all core damage accident progression bins for which a failure to isolate the containment occurs. These sequences are dominated by failure-to-close of large containment isolation valves. The frequency per year for these sequences is 2.31E-9/year [3.15E-9/year] and is determined by the frequency of Release Category 2 on Table 4.2-3.

Class 3 Sequences.

This group consists of all core damage accident progression bins for which a pre-existing leakage in the containment structure (e.g., containment liner) exists. The containment leakage for these sequences can be either small ($2.0L_a$ to $35L_a$) or large ($>35L_a$). For 10-yr and 15-yr test intervals, there is a likelihood that corrosion related containment leakage may not be detected. Therefore, the baseline frequency for Class 3B sequences is increased by a factor of 1.00269 to account for undetected corrosion related containment leakage. See Appendix A for basis and supporting calculations. Note that this factor is based on a test interval increase from 3 years to 15 years, but was conservatively applied to both the 10-year and 15-year cases.

The respective frequencies per year (excluding corrosion related leakage) are determined as follows:

$PROB_{Class\_3a}$ = probability of small pre-existing containment liner leakage
= 0.064 [see Section 4.3]

$PROB_{Class\_3b}$ = probability of large pre-existing containment liner leakage
= 0.021 [see Section 4.3]

Unit 1:

CLASS_3a_FREQUENCY = 0.064 * 1.61E-5/year = 1.03E-6/year

CLASS_3b_FREQUENCY = 0.021 * 1.61E-5/year = 3.38E-7/year

Unit 2:

CLASS_3a_FREQUENCY = 0.064 * 2.16E-5/year = 1.38E-6/year

CLASS_3b_FREQUENCY = 0.021 * 2.16E-5/year = 4.54E-7/year

Class 4 Sequences.

This group consists of all core damage accident progression bins for which a containment isolation failure-to-seal of Type B test components occurs. However, as these failures are detected by Type B tests which are unaffected by changes in the Type A ILRT frequency, this group is not evaluated any further in the analysis.

Class 5 Sequences.

This group consists of all core damage accident progression bins for which a containment isolation failure-to-seal of Type C test components. However, as these failures are detected by Type C tests which are unaffected by changes in the Type A ILRT frequency, this group is not evaluated any further in this analysis.

Class 6 Sequences.

This group is similar to Class 2. These are sequences that involve core damage accident progression bins for which a failure-to-seal containment leakage due to failure to isolate the containment occurs. These sequences are dominated by misalignment of containment isolation valves following a test/maintenance evolution. However, as these failures are unaffected by changes in the Type A ILRT frequency, this group is not evaluated any further in this analysis.

Class 7 Sequences.

This group consists of all core damage accident progression bins in which containment failure is induced by severe accident phenomena (e.g., direct containment heating, melt-through, overpressure). The baseline frequency per year for these sequences is 4.38E-7/year [8.27E-7/year] and is determined by the difference between the total core damage frequency and the sum of the other accident class frequencies on Table 4.2-3.

<u>Class 8 Sequences</u>.

This group consists of all core damage accident progression bins in which containment bypass occurs. The frequency per year for these sequences is 2.68E-6/year [2.68E-6/year] and is determined by the sum of the frequencies for Steam Generator Tube Rupture and Intersystem LOCA accident classes as shown on Table 4.2-3.

<u>Summary of Accident Class Frequencies</u>

In summary, the accident sequence frequencies that can lead to radionuclide release to the public have been derived consistent with the definition of Accident Classes defined in EPRI-TR-104285. Table 5-2 summarizes these accident frequencies by Accident Class.

Table 5-2

EPRI ACCIDENT CLASS FREQUENCIES

EPRI Accident Class	Description	EPRI Accident Class Frequency (per year)		Contribution to CDF (%)	
		Unit 1	Unit 2	Unit 1	Unit 2
1	No Containment Failure	1.16E-05	1.63E-05	72.09%	75.27%
2	Large Isolation Failures (Fail to Close)	2.31E-09	3.15E-09	0.01%	0.01%
3A	Small Isolation Failures (Liner Breach)	1.03E-06	1.38E-06	6.40%	6.40%
3B	Large Isolation Failures (Liner Breach)	3.38E-07	4.54E-07	2.10%	2.10%
4	Small Isolation Failures (Fail to Seal - Type B)	0.00E+00	0.00E+00	0.00%	0.00%
5	Small Isolation Failures (Fail to Seal - Type C)	0.00E+00	0.00E+00	0.00%	0.00%
6	Other Isolation Failures (e.g., dependent failures)	0.00E+00	0.00E+00	0.00%	0.00%
7	Failures induced by Phenomena (early and late)	4.38E-07	8.27E-07	2.72%	3.82%
8	Bypass (Interfacing Systems LOCA)	2.68E-06	2.68E-06	16.67%	12.39%
Total		**1.61E-05**	**2.16E-05**	**100.0**	**100.0**

5.2 STEP 2 – DEVELOP CLASS 3 POPULATION DOSE PER REACTOR YEAR

The development of consequence measures (population doses) for all EPRI accident classes except Class 3 was presented in Section 4.2 above.

As described in Section 5.1 above, Class 3 is further divided for this analysis into Class 3a and Class 3b due to their different consequences in terms of containment leakage. For this analysis, the associated containment leakage for Class 3a is $10L_a$ and for Class 3b is $35L_a$. These assignments are consistent with the Indian Point 3 ILRT submittal [14] which was approved by the NRC [21].

Class 1 is considered to cover only containment leakage for the assumed intact containment at the leakage limit of $1L_a$. Therefore, the population doses applied to the Class 3a and Class 3b sequences is determined as follows:

Class 3a = 8.97E+01 person-rem x $10L_a$ = 8.97E+02 person-rem

Class 3b = 8.97E+01 person-rem x $35L_a$ = 3.14E+03 person-rem

The population dose estimates derived for use in the risk evaluation for all EPRI accident classes are summarized in Table 5-3.

Table 5-3
POPULATION DOSE ESTIMATES FOR
ENTIRE REGION SURROUNDING PRAIRIE ISLAND

Accident Classes (Containment Release Type)	Description	Person-Rem (Entire Region)
1	No Containment Failure	8.97E+01
2	Large Isolation Failures (Failure to Close)	4.07E+06
3a	Small Isolation Failures (liner breach)	8.97E+02
3b	Large Isolation Failures (liner breach)	3.14E+03
4	Small Isolation Failures (Failure to seal-Type B)	0
5	Small Isolation Failures (Failure to seal-Type C)	0
6	Other Isolation Failures (e.g., dependent failures)	0
7	Failures Induced by Phenomena	2.16E+06
8	Bypass (SGTR, Interfacing System LOCA)	1.24E+07

The above results, when combined with the results presented in Table 5-2, yield the baseline mean consequence measures for each accident class. These results are presented in Table 5-4.

Table 5-4
ANNUAL DOSE (PERSON-REM/YR) AS A FUNCTION OF ACCIDENT CLASS CHARACTERISTIC OF CONDITIONS FOR ILRT REQUIRED 3/10 YEARS (I.E., REPRESENTATIVE OF ILRT DATA)

EPRI Accident Class	Description	EPRI Accident Class Frequency (per year)		Population Dose for Entire Region (person-rem)	Population Dose Rate for Entire Region (person-rem/yr)	
		Unit 1	Unit 2		Unit 1	Unit 2
1	No Containment Failure	1.16E-05	1.63E-05	8.97E+01	1.040E-03	1.461E-03
2	Large Isolation Failures (Fail to Close)	2.31E-09	3.15E-09	4.07E+06	9.409E-03	1.282E-02
3a	Small Isolation Failures (Liner Breach)	1.03E-06	1.38E-06	8.97E+02	9.232E-04	1.242E-03
3b	Large Isolation Failures (Liner Breach)	3.38E-07	4.54E-07	3.14E+03	1.060E-03	1.426E-03
4	Small Isolation Failures (Fail to Seal - Type B)	0.00E+00	0.00E+00	0	0.000E+00	0.000E+00
5	Small Isolation Failures (Fail to Seal - Type C)	0.00E+00	0.00E+00	0	0.000E+00	0.000E+00
6	Other Isolation Failures (e.g., dependent failures)	0.00E+00	0.00E+00	0	0.000E+00	0.000E+00
7	Failures induced by Phenomena (early and late)	4.38E-07	8.27E-07	2.16E+06	9.468E-01	1.789E+00
8	Bypass (Interfacing Systems LOCA)	2.68E-06	2.68E-06	1.24E+07	3.317E+01	3.318E+01
Total		**1.61E-05**	**2.16E-05**		**34.1332**	**34.9840**

The total dose per year is compared with the other sites as shown below:

Plant	Annual Dose (Person-Rem/yr)	Reference
Indian Point 3	14.515	14
Peach Bottom	6.2	15
Crystal River	1.4	16
Prairie Island 1	34.1332	Table 5-4
Prairie Island 2	34.9840	Table 5-4

Note that the above calculated annual dose values per year for Prairie Island are the baseline values for this risk assessment (ILRTs performed at current frequency).

Based on the risk values from Table 5-4, the percent risk contribution ($\%Risk_{BASE}$) for Class 3 (i.e., the Class affected by the ILRT interval change) is as follows:

$$\%Risk_{BASE} = [(CLASS3a_{BASE} + CLASS\ 3b_{BASE}) / Total_{BASE}] \times 100$$

For Unit 1:

$CLASS3a_{BASE}$= Class 3a person-rem/year = 9.23-04 person-rem/year [Table 5-4]

$CLASS3b_{BASE}$= Class 3b person-rem/year = 1.06E-3 person-rem/year [Table 5-4]

$TOTAL_{BASE}$ = Total person-rem/yr for baseline interval
= 34.1332 person-rem/yr [Table 5-4]

$\%Risk_{BASE}$ = [(9.23-04 + 1.06E-3)/34.1332] x 100

$\%Risk_{BASE}$ = 0.058%

For Unit 2:

$CLASS3a_{BASE}$= Class 3a person-rem/year = 1.24E-3 person-rem/year [Table 5-4]

$CLASS3b_{BASE}$= Class 3b person-rem/year = 1.43E-3 person-rem/year [Table 5-4]

$TOTAL_{BASE}$ = Total person-rem/yr for baseline interval
= 34.9840 person-rem/yr [Table 5-4]

$\%Risk_{BASE}$ = [(1.24E-3 +1.43E-3)/34.9840] x 100

$\%Risk_{BASE}$ = 0.076%

5.3 STEP 3 - EVALUATE RISK IMPACT OF EXTENDING TYPE A TEST INTERVAL FROM 10-TO-15 YEARS

According to NUREG-1493 [4], relaxing the Type A ILRT interval from 3-in-10 years to 1-in-10-years will increase the average time that a leak (detectable only by an ILRT) goes undetected from 1.5 years to 5 years. The average time for failure to detect is calculated using the approximation ½ λT where T is the Test interval and λ, the leakage failure rate, is (3%)/1.5 year. If the test interval is extended to 1 in 15 years, the average time that a leak detectable only by an ILRT test goes undetected increases to 7.5 years (1/2 * 15 years.). Because ILRTs only detect about 3% of leaks (the rest are identified during LLRTs), the result for a 10-yr ILRT interval is a 10% undetectable rate in the overall probability of leakage ½ * (3% /1.5 years) * 10 years.

This value is determined by multiplying 3% and the ratio of the average time for non-detection for the increased ILRT test interval to the baseline average time for non-detection. For a 15-yr-test interval, the result is a 15% overall probability of leakage (i.e., ½ * (3% /1.5 yrs) * 15 years). Thus, increasing the ILRT test interval from 10 years to 15 years translates into a 5% increase in the overall leakage probability.

<u>Risk Impact due to 10-year Test Interval</u>

As previously stated, Type A tests impact only Class 3 sequences. For Class 3 sequences, the release magnitude is not impacted by the change in test interval, (a small or large breach remains the same, even though the probability of not detecting the breach increases). Thus, only the frequency of Class 3 sequences is impacted. Therefore, for Class 3 sequences, the risk contribution is determined by multiplying the Class 3 accident frequency by the increase in probability of leakage of 1.1 (7% which is approximated here as a factor of 1.1 consistent with the approach used by Indian Point 3 [14]). Specifically, there is a factor of 1.1

increase in the Class 3a and 3b frequencies relative to the baseline associated with increasing the ILRT test interval from 3 yrs to 10 yrs. (See Section 4.4)

<u>Risk Impact of Corrosion-Related Leakage On Increase to 15-year Test Interval</u>

Increasing the test interval from 3 to 15 years may reduce the chance of detecting corrosion related leakage. The likelihood of not detecting corrosion related leakage due to increased test interval from 3 to 15 years is calculated to be 0.0269%. Details of this calculation are provided in Appendix A. Consistent with the Kewaunee ILRT Extension submittal, the calculation assumes factors determining increased undetected containment leakage from areas both potentially in contact with foreign materials (in contact with concrete) and areas not potentially in contact with foreign materials are exposed to corrosion. The increased likelihood of corrosion related leakage is assumed to increase LERF frequency contributions from phenomena-related accident sequences (EPRI Class 7) by a factor of 1.000269. This factor is conservatively applied to both the 10-year and 15-year test interval calculations.

The results of the 10 year test interval calculation are presented in Table 5-5. Based on the Table 5-5 values, the Type A 10-year test frequency percent risk contribution ($\%Risk_{10}$) for Class 3 is as follows:

For Unit 1:

$(\%Risk_{10}) = [(CLASS3a_{10} + CLASS3b_{10}) / Total_{10}] \times 100$

Where:

$CLASS\ 3a_{10}$ = Class 3a person-rem/year = 1.02E-3 person-rem/yr [Table 5-5]

$CLASS\ 3b_{10}$ = Class 3b person-rem/year = 1.17E-3 person-rem/yr [Table 5-5]

$TOTAL_{10}$ = Total person-rem/yr for 10-year interval = 34.1334 person-rem/yr [Table 5-5]

$\%Risk_{10}$ = [(1.02E-3+ 1.17E-3) / 34.1334] x 100

% $Risk_{10}$ = 0.0064%

For Unit 2:

($\%Risk_{10}$)= [($CLASS3a_{10}$ + $CLASS3b_{10}$) / $Total_{10}$] x 100

Where:

CLASS $3a_{10}$ = Class 3a person-rem/year = 1.37E-3 person-rem/yr [Table 5-5]

CLASS $3b_{10}$ = Class 3b person-rem/year = 1.57E-3 person-rem/yr [Table 5-5]

$TOTAL_{10}$ = Total person-rem/yr for 10-year interval = 34.9843 person-rem/yr [Table 5-5]

$\%Risk_{10}$ = [(1.37E-3 +1.57E-3) / 34.9843] x 100

% $Risk_{10}$ = 0.0084%

Therefore, the Total Type A 10-year ILRT interval risk contribution of leakage, represented by Class 3 accident scenarios is 0.0064% for Unit 1, and 0.0084% for Unit 2.

The percent risk increase ($\Delta\%Risk_{10}$) due to a ten-year ILRT over the baseline case is as follows:

$\Delta\%Risk_{10}$ = [($Total_{10}$ – $Total_{BASE}$) / $Total_{BASE}$] x 100.0

For Unit 1:

$TOTAL_{BASE}$ = Total person-rem/yr for baseline interval = 34.1332 person-rem/yr [Table 5-4]

$TOTAL_{10}$ = Total person-rem/yr for 10 yr ILRT interval = 34.1334 person-rem/yr [Table 5-5]

$\Delta\%Risk_{10} = [(34.1334 - 34.1332) / 34.1332] \times 100.0$

$\Delta\%Risk_{10} = 0.0005\%$

For Unit 2:

$TOTAL_{BASE}$ = Total person-rem/yr for baseline interval = 34.9840 person-rem/yr [Table 5-4]

$TOTAL_{10}$ = Total person-rem/yr for 10 yr ILRT interval = 34.985 person-rem/yr [Table 5-5]

$\Delta\%Risk_{10} = [(34.9843 - 34.9840) / 34.9840] \times 100.0$

$\Delta\%Risk_{10} = 0.0007\%$

Therefore, the increase in risk contribution because of the change to the already approved ten-year ILRT test frequency from three-in-ten years to 1-in-ten-years is 0.0005% for Unit 1, and 0.0007% for Unit 2.

Table 5-5
ANNUAL DOSE (PERSON-REM/YR) AS A FUNCTION OF ACCIDENT CLASS CHARACTERISTIC OF CONDITIONS FOR ILRT REQUIRED EVERY 10 YEARS

EPRI Accident Class	Description	EPRI Accident Class Frequency (per year)		Population Dose for Entire Region (person-rem)	Population Dose Rate for Entire Region (person-rem/yr)	
		Unit 1	Unit 2		Unit 1	Unit 2
1	No Containment Failure	1.15E-05	1.61E-05	8.97E+01	1.028E-03	1.444E-03
2	Large Isolation Failures (Fail to Close)	2.31E-09	3.15E-09	4.07E+06	9.409E-03	1.282E-02
3a	Small Isolation Failures (Liner Breach)	1.13E-06	1.52E-06	8.97E+02	1.016E-03	1.366E-03
3b	Large Isolation Failures (Liner Breach)	3.71E-07	5.00E-07	3.14E+03	1.167E-03	1.569E-03
4	Small Isolation Failures (Fail to Seal - Type B)	0.00E+00	0.00E+00	0	0.000E+00	0.000E+00
5	Small Isolation Failures (Fail to Seal - Type C)	0.00E+00	0.00E+00	0	0.000E+00	0.000E+00
6	Other Isolation Failures (e.g., dependent failures)	0.00E+00	0.00E+00	0	0.000E+00	0.000E+00
7	Failures induced by Phenomena (early and late)	4.38E-07	8.27E-07	2.16E+06	9.468E-01	1.789E+00
8	Bypass (Interfacing Systems LOCA)	2.68E-06	2.68E-06	1.24E+07	3.317E+01	3.318E+01
Total		1.61E-05	2.16E-05		34.1334	34.9843

Risk Impact Due to 15-Year Test Interval

The risk contribution for a 15-year interval is calculated in a manner similar to the 10-year interval. The difference is in the increase in probability of leakage in Classes 3a and 3b. For this case, the value used in the analysis is 15 percent or 1.15 consistent with previously approved method [14, 21]. Specifically, there is an increase in Class 3a and 3b frequencies by a factor of 1.15 relative to the baseline associated with increasing the ILRT test interval from 3 yrs to 15 yrs. (See Section 4.4) The results for this calculation are presented in Table 5-6.

Based on the values from Table 5-6, the Type A 15-year test frequency percent risk contribution ($\%Risk_{15}$) for Class 3 is as follows:

For Unit 1:

$(\%Risk_{15}) = [(CLASS3a_{15} + CLASS3b_{15}) / Total_{15}] \times 100$

Where:

$CLASS\ 3a_{15}$ = Class 3a person-rem/year = 1.06E-3 person-rem/yr [Table 5-6]

$CLASS\ 3b_{15}$ = Class 3b person-rem/year = 1.22E-3 person-rem/yr [Table 5-6]

$TOTAL_{15}$ = Total person-rem/yr for 10-year interval = 34.1334 person-rem/yr [Table 5-6]

$\%Risk_{15} = [(1.06E-3 + 1.22E-3) / 34.1334] \times 100$

$\%\ Risk_{15} = 0.0067\%$

For Unit 2:

$(\%Risk_{15}) = [(CLASS3a_{15} + CLASS3b_{15}) / Total_{10}] \times 100$

Where:

$CLASS\ 3a_{15}$ = Class 3a person-rem/year = 1.43E-3 person-rem/yr [Table 5-6]

$CLASS\ 3b_{15}$ = Class 3b person-rem/year = 1.64E-3 person-rem/yr [Table 5-6]

$TOTAL_{15}$ = Total person-rem/yr for 10-year interval = 34.9844 person-rem/yr [Table 5-5]

$\%Risk_{15} = [(1.43E-3 + 1.64E-3) / 34.9844] \times 100$

$\%\ Risk_{15} = 0.0088\%$

Therefore, the Total Type A 15-year ILRT interval risk contribution of leakage, represented by Class 3 accident scenarios is 0.0067% for Unit 1, and 0.0088% for Unit 2.

The percent risk increase ($\Delta\%Risk_{15}$) due to a 15-year ILRT over the baseline case is as follows:

$$\Delta\%Risk_{15} = [(Total_{15} - Total_{BASE}) / Total_{BASE}] \times 100.0$$

For Unit 1:

$TOTAL_{BASE}$ = Total person-rem/yr for baseline interval = 34.1332 person-rem/yr [Table 5-4]

$TOTAL_{15}$ = Total person-rem/yr for 10 yr ILRT interval = 34.1334 person-rem/yr [Table 5-6]

$$\Delta\%Risk_{15} = [(34.1334 - 34.1332) / 34.1332] \times 100.0$$

$$\Delta\%Risk_{15} = 0.0008\%$$

For Unit 2:

$TOTAL_{BASE}$ = Total person-rem/yr for baseline interval = 34.9840 person-rem/yr [Table 5-4]

$TOTAL_{10}$ = Total person-rem/yr for 10 yr ILRT interval = 34.9844 person-rem/yr [Table 5-6]

$$\Delta\%Risk_{15} = [(34.9844 - 34.9840) / 34.9840] \times 100.0$$

$$\Delta\%Risk_{15} = 0.0011\%$$

Therefore, the total increase in risk contribution associated with relaxing the ILRT test frequency from three-in-ten-years to one-per-fifteen years is 0.0008% for Unit 1, and 0.0011% for Unit 2.

The percent increase on the <u>total integrated plant risk</u> when the ILRT is extended from 10 years to 15 years is computed as follows:

$$\%TOTAL_{10\text{-}15} = [(TOTAL_{15} - TOTAL_{10}) / TOTAL_{10}] \times 100$$

For Unit 1:

$TOTAL_{10}$ = Total person-rem/year for 10-year interval
= 34.13335 person-rem/year [Table 5-5, expanded to 5th decimal place]

$TOTAL_{15}$ = Total person-rem/year for 15-year interval
= 34.13344 person-rem/year [Table 5-6, expanded to 5th decimal place]

$\%TOTAL_{10\text{-}15} = [(34.13344 - 34.13335) / 34.13335] \times 100$
$\%TOTAL_{10\text{-}15} = 0.0003\%$

Therefore, the impact on the total plant risk for these accident sequences, as influenced by Type A testing, is 0.0003% when going from a 10-year ILRT interval to a 15-year interval.

For Unit 2:

$TOTAL_{10}$ = Total person-rem/year for 10-year interval
= 34.98425 person-rem/year [Table 5-5, expanded to 5th decimal place]

$TOTAL_{15}$ = Total person-rem/year for 15-year interval
= 34.98438 person-rem/year [Table 5-6, expanded to 5th decimal place]

$\%TOTAL_{10\text{-}15} = [(34.98438 - 34.98425) / 34.98425] \times 100$
$\%TOTAL_{10\text{-}15} = 0.0004\%$

Therefore, the impact on the total plant risk for these accident sequences, as influenced by Type A testing, is 0.0004% when going from a 10-year ILRT interval to a 15-year interval

Table 5-6
ANNUAL DOSE RATE (PERSON-REM/YR) AS A FUNCTION OF ACCIDENT CLASS CHARACTERISTIC OF CONDITIONS FOR ILRT REQUIRED EVERY 15 YEARS

EPRI Accident Class	Description	EPRI Accident Class Frequency (per year)		Population Dose for Entire Region (person-rem)	Population Dose Rate for Entire Region (person-rem/yr)	
		Unit 1	Unit 2		Unit 1	Unit 2
1	No Containment Failure	1.14E-05	1.60E-05	8.97E+01	1.022E-03	1.436E-03
2	Large Isolation Failures (Fail to Close)	2.31E-09	3.15E-09	4.07E+06	9.409E-03	1.282E-02
3a	Small Isolation Failures (Liner Breach)	1.18E-06	1.59E-06	8.97E+02	1.062E-03	1.428E-03
3b	Large Isolation Failures (Liner Breach)	3.88E-07	5.22E-07	3.14E+03	1.220E-03	1.641E-03
4	Small Isolation Failures (Fail to Seal - Type B)	0.00E+00	0.00E+00	0	0.000E+00	0.000E+00
5	Small Isolation Failures (Fail to Seal - Type C)	0.00E+00	0.00E+00	0	0.000E+00	0.000E+00
6	Other Isolation Failures (e.g., dependent failures)	0.00E+00	0.00E+00	0	0.000E+00	0.000E+00
7	Failures induced by Phenomena (early and late)	4.38E-07	8.27E-07	2.16E+06	9.468E-01	1.789E+00
8	Bypass (Interfacing Systems LOCA)	2.68E-06	2.68E-06	1.24E+07	3.317E+01	3.318E+01
Total		**1.61E-05**	**2.16E-05**		**34.1334**	**34.9844**

5.4 STEP 4 – DETERMINE THE CHANGE IN RISK IN TERMS OF LARGE EARLY RELEASE FREQUENCY (LERF)

The risk increase associated with extending the ILRT interval involves the potential that a core damage event that normally would result in only a small radioactive release from an intact containment could in fact result in a larger release due to the increase in probability of failure to detect a pre-existing leak. Class 3b is treated in this analysis as a potential LERF contributor. Class 3a is not treated as a "large" release. Therefore, for this evaluation, only Class 3b sequences have the potential to result in large releases if a pre-existing leak were present. Class 1 sequences are not considered as potential large release pathways because the containment remains intact. Therefore, the containment leak rate is expected to be small. Other accident classes such as 2, 6, 7, and 8 could result in large releases, but these are not affected by the change in ILRT interval. Late releases are excluded regardless of the size of the leak because late releases are, by definition, not part of LERF.

Reg. Guide 1.174[3] provides guidance for determining the risk impact of plant-specific changes to the licensing basis. Reg. Guide 1.174 defines very small changes in risk as resulting in increases of core damage frequency (CDF) below 10^{-6}/yr and increases in LERF below 10^{-7}/yr. Because the ILRT does not impact CDF, the relevant metric is LERF. Calculating the increase in LERF requires determining the impact of the ILRT interval on the leakage probability.

Baseline (3 Yr Test Interval) LERF

From the Rev. 2.1 PRA results, the baseline LERF frequency is:

For Unit 1:

$LERF_{PRA}$ = 5.74E-07/year

$LERF_{BASE}$ = 5.74E-07/year

For Unit 2:

$LERF_{PRA}$ = 5.75E-07/year

$LERF_{BASE}$ = 5.75E-07/year

LERF for 10-Yr Test Interval

The LERF increase ($\Delta LERF_{10\text{-}BASE}$) due to a 10-year ILRT over the baseline is as follows:

$$\Delta LERF_{10\text{-}BASE} = CLASS3b_{10} - CLASS3b_{BASE}$$

The LERF ($LERF_{10}$) due to a 10-year ILRT is calculated as follows

$$LERF_{10} = LERF_{BASE} + \Delta LERF_{10\text{-}BASE}$$

For Unit 1:

$CLASS3b_{10}$ = 3.71E-07/year [Table 5-5]
$CLASS3b_{BASE}$ = 3.38E-07/year [Table 5-4]

$\Delta LERF_{10\text{-}BASE}$ = 3.71E-07/year - 3.38E-07/year = 3.39E-08/yr
$LERF_{10}$ = 5.74E-07/year + 3.39E-08/year = 6.08E-07/year

For Unit 2:

$CLASS3b_{10}$ = 5.00E-07/year [Table 5-5]
$CLASS3b_{BASE}$ = 4.54E-07/year [Table 5-4]

$\Delta LERF_{10\text{-}BASE}$ = 5.00E-07/year - 4.54E-07/year = 4.55E-08/yr
$LERF_{10}$ = 5.75E-07/year + 4.55E-08/year = 6.20E-07/year

LERF for 15-Yr Test Interval

The LERF increase ($\Delta LERF_{15\text{-}BASE}$) due to a 15-year ILRT over the baseline is as follows:

$$\Delta LERF_{15\text{-}BASE} = CLASS3b_{15} - CLASS3b_{BASE}$$

The LERF ($LERF_{15}$) due to a 15-year ILRT is calculated as follows

$$LERF_{15} = LERF_{BASE} + \Delta LERF_{15\text{-}BASE}$$

For Unit 1:

$CLASS3b_{15}$ = 3.88E-07/year [Table 5-6]
$CLASS3b_{BASE}$ = 3.38E-07/year [Table 5-4]

$\Delta LERF_{15\text{-}BASE}$ = 3.88E-07/year – 3.38E-07/year = 5.07E-08/year
$LERF_{15}$ = 5.74E-07/year + 5.07E-08/yr = 6.24E-07/year

For Unit 2:

$CLASS3b_{15}$ = 5.22E-07/year [Table 5-6]
$CLASS3b_{BASE}$ = 4.54E-07/year [Table 5-4]

$\Delta LERF_{15\text{-}BASE}$ = 5.22E-07/year – 4.54E-07/year = 6.83E-08/year
$LERF_{15}$ = 5.75E-07/year + 6.83E-08/year = 6.43E-07/year

The LERF increase ($\Delta LERF_{15\text{-}10}$) due to a 15-year ILRT over the 10-yr ILRT is as follows:

$$\Delta LERF_{15\text{-}10} = CLASS3b_{15} - CLASS3b_{10}$$

For Unit 1:

$CLASS3b_{15}$ = 3.88E-07/year [Table 5-6]
$CLASS3b_{10}$ = 3.71E-07/year [Table 5-5]

$\Delta LERF_{15\text{-}10}$ = 3.88E-07/year – 3.71E-07/year = 1.69E-08/year

For Unit 2:

$CLASS3b_{15}$ = 5.22E-07/year [Table 5-6]
$CLASS3b_{10}$ = 5.00E-07/year [Table 5-5]

$\Delta LERF_{15\text{-}10}$ = 5.22E-07/year – 5.00E-07/year = 2.27E-08/year

It should be noted that the calculated changes in LERF for all cases are well below the 1.0E-7/yr screening criterion in Reg. Guide 1.174 and represent a very small change in risk.

5.5 IMPACT ON THE CONDITIONAL CONTAINMENT FAILURE PROBABILITY (CCFP)

Another parameter that the NRC Guidance Reg. Guide 1.174 states can provide input into the decision-making process is the consideration of change in the conditional containment failure probability (CCFP). The change in CCFP is indicative of the effect of the ILRT on all radionuclide releases, not just LERF. The conditional containment failure probability (CCFP) is calculated from the risk calculations performed in this analysis. The CCFP is "conditional" in that it identifies the probability of containment failure given that a severe accident (i.e., core damage) has occurred. Containment failure in this context includes all radionuclide release end states other than the intact state that do not involve containment bypass. Generally, this means non-bypass, non-Class 1 sequences. Since the only classes that are increasing are Classes 3a and 3b, the change in CCFP can be calculated by the difference in these classes.

The percent increase in CCFP ($\Delta\%CCFP_{BASE-10}$) due to a 10-year ILRT over the baseline is as follows:

For Unit 1:

$\Delta\%CCFP_{BASE-10} =$

$[((F_{CLASS\ 3a\_10} + F_{CLASS\ 3b\_10}) - (F_{CLASS\ 3a\_BASE} + F_{CLASS3b\_BASE}))\ /CDF] \times 100$

$= [((1.13E\text{-}06 + 3.71E\text{-}07) - (1.03E\text{-}06 + 3.38E\text{-}07))\ /\ 1.61E\text{-}05] \times 100$

$= 0.851\%$

For Unit 2:

$\Delta\%CCFP_{BASE-10} =$

$[((F_{CLASS\ 3a\_10} + F_{CLASS\ 3b\_10}) - (F_{CLASS\ 3a\_BASE} + F_{CLASS3b\_BASE}))\ /CDF] \times 100$

$= [((1.52E\text{-}06 + 5.00E\text{-}07) - (1.38E\text{-}06 + 4.54E\text{-}07))\ /\ 2.16E\text{-}05] \times 100$

$= 0.8506\%$

The percent increase in CCFP increase ($\Delta\%CCFP_{BASE\text{-}15}$) due to a 15-year ILRT over the baseline is as follows:

For Unit 1:

$\Delta\%CCFP_{BASE\text{-}15} =$
$[((F_{CLASS\ 3a\_15} + F_{CLASS\ 3b\_15}) - (F_{CLASS\ 3a\_BASE} + F_{CLASS3b\_BASE})) / CDF] \times 100$
$= [((1.18E\text{-}06 + 3.88E\text{-}07) - (1.03E\text{-}06 + 3.38E\text{-}07)) / 1.61E\text{-}05] \times 100$
$= 1.2756\%$

For Unit 2:

$\Delta\%CCFP_{BASE\text{-}15} =$
$[((F_{CLASS\ 3a\_15} + F_{CLASS\ 3b\_15}) - (F_{CLASS\ 3a\_BASE} + F_{CLASS3b\_BASE})) / CDF] \times 100$
$= [((1.59E\text{-}06 + 5.22E\text{-}07) - (1.38E\text{-}06 + 4.54E\text{-}07)) / 2.16E\text{-}05] \times 100$
$= 1.2756\%$

The percent increase in CCFP increase ($\Delta\%CCFP_{15\text{-}10}$) due to a 15-year ILRT over the 10-year ILRT is as follows:

For Unit 1:

$\Delta\%CCFP_{15\text{-}10} =$
$[((F_{CLASS\ 3a\_15} + F_{CLASS\ 3b\_15}) - (F_{CLASS\ 3a\_10} + F_{CLASS\ 3b\_10})) / CDF] \times 100$
$= [((1.18E\text{-}06 + 3.88E\text{-}07) - (1.13E\text{-}06 + 3.71E\text{-}07)) / 1.61E\text{-}05] \times 100$
$= 0.0003\%$

For Unit 2:

$\Delta\%CCFP_{15\text{-}10} =$

$$[((F_{CLASS\ 3a\_15} + F_{CLASS\ 3b\_15}) - (F_{CLASS\ 3a\_10} + F_{CLASS\ 3b\_10}))\ /CDF] \times 100$$

$$= [((1.59E\text{-}06 + 5.22E\text{-}07) - (1.52E\text{-}06 + 4.99E\text{-}07))/\ 2.16E\text{-}05] \times 100$$

$$= 0.0004\%$$

This change in CCFP of less than 1% is judged to be insignificant and reflects sufficient defense-in-depth.

5.6 RESULTS SUMMARY

The following is a brief summary of some of the key aspects of the ILRT test interval extension risk analysis (using EPRI TR-104285 methodology):

1. The baseline risk contribution (person-rem/yr) associated with containment leakage affected by the ILRT and represented by Class 3 accident scenarios is 0.0058% [0.0076%] of the total risk.

2. When the ILRT interval is 10 years, the risk contribution of leakage (person-rem/yr) represented by Class 3 accident scenarios is increased insignificantly (contribution is 0.0064% [0.0084%] of the total risk).

3. The total integrated increase in risk contribution from reducing the ILRT test frequency from 3-per-10-year (baseline) frequency to once-per-10 years is near zero (0.0005% [0.0007%]).

4. When the ILRT interval is 15 years, the risk contribution of leakage (person-rem/yr) represented by Class 3 accident scenarios is increased insignificantly (contribution is 0.0067% [0.0088%] of the total risk).

5. The total integrated increase in risk contribution from reducing the ILRT test frequency from 3-per-10-year (baseline) frequency to once-per-15 years is near zero (0.0008% [0.0011%]).

6. The total integrated increase in risk contribution from reducing the ILRT test frequency from the once-per-10-year frequency to once-per-15 years is near zero (0.0003% [0.0004%]).

7. There is no change in the at-power CDF associated with the ILRT extension. Therefore, this is within the Reg. Guide 1.174 acceptance guidelines.

8. The risk increase in LERF from the original 3-in-10 years test frequency to once-per-10 years is 3.39E-08/yr [4.55E-08/yr]. This is considered to be "very small" using the acceptance guidelines in Reg. Guide 1.174.

9. The risk increase in LERF from the original 3-in-10 years test frequency to once-per-15 years is 5.07E-08/yr [6.83E-08/yr]. This is also considered to be "very small" using the acceptance guidelines in Reg. Guide 1.174.

10. The risk increase in LERF from reducing the ILRT test frequency from once-per-10 years to one-per-15 years is 1.69E-08/yr [2.27E-08/yr]. This is determined to be a very small increase using the acceptance guidelines of Reg. Guide 1.174.

11. The change in CCFP of less than 1% [less than 1%] for both cases (when reducing test frequency to either once-per-10 or to once-per-15 years), is judged to be insignificant and reflects sufficient defense-in-depth.

Other significant results are summarized in Table 5-7.

Table 5-7
SUMMARY OF RISK IMPACT OF TYPE A ILRT TEST FREQUENCIES

Risk Metric	Risk Impact (Baseline)		Risk Impact (10-years)		Risk Impact (15-years)	
	Unit 1	Unit 2	Unit 1	Unit 2	Unit 1	Unit 2
Class 3a and 3b Risk Contribution	0.0058% of total integrated value 1.98E-3 person-rem/yr	0.0076% of total integrated value 2.67E-3 person-rem/yr	0.0064% of total integrated value 2.18E-3 person-rem/yr	0.0084% of total integrated value 2.94E-3 person-rem/yr	0.0067% of total integrated value 2.28E-3 person-rem/yr	0.0084% of total integrated value 3.07E-3 person-rem/yr
Total Integrated Risk	34.1332 person-rem/year	34.9840 person-rem/year	34.1334 person-rem/year	34.9843 person-rem/year	34.1334 person-rem/year	34.9844 person-rem/year
Percent Increase in Integrated Risk over Baseline	N/A	N/A	0.0005%	0.0007%	0.0008%	0.0011%
Increase in LERF over Baseline	N/A	N/A	3.39E-08/yr	4.55E-08/yr	5.07E-08/yr	6.83E-08/yr
Percent Increase in CCFP over Baseline	N/A	N/A	0.851%	0.850%	1.28%	1.28%

Section 6

APPLICATION OF NEI INTERIM GUIDANCE METHODOLOGY

6.1 SUMMARY OF METHODOLOGY

The results of the risk assessment performed using the methodology of EPRI TR-104285 [2] was provided in Section 5 of this document. In 2001, NEI recognized a need to update this methodology to support future risk-informed ILRT interval extension submittals. The methodology update was focused in three particular areas:

1. The methodology for determining the overall probability of leakage resulting from extending surveillance intervals was revised. For an ILRT interval extension from 3 in 10 years to 1 in 10 years for example, the overall 10-year dose should have been calculated using an increased probability of an undetected leak (a leak detectable only by an ILRT that goes undetected due to the increased test interval) of 333.3% (increased by a factor of 3.33), as opposed to the 10% value used in the EPRI TR-104285 methodology. However, NEI also showed this methodology change to have only a very small incremental risk contribution, since ILRTs only address a very small portion of the severe accident risk.

2. The methodology used to determine the frequencies of leakages detectable only by ILRTs (EPRI Classes 3a and 3b) was revised. Updated ILRT failure data was incorporated into the calculation of these containment failure classes. The Guidance recommended use of a mean frequency calculation for the Class 3a distribution, and recommended the use of a Jeffery's non-informative prior distribution for the Class 3b distribution. The impact of this methodology change was to increase the probability of Class 3b releases. However, it was

noted that no observed failure to date was even close in size to that necessary to cause a large release.

3. The updated guidance included provisions for utilizing NUREG-1150 dose calculations, a necessary improvement to make the methodology usable for plants that do not have a Level-3 PRA.

Other improvements in the methodology include use of a simplified risk model (as opposed to the Containment Event Tree model used in EPRI TR-104285) to distinguish between those accident sequences that are affected by the status of the containment isolation system versus those that are a direct function of severe accident phenomena, and evaluation of the change in large early release frequency (LERF) by manipulating the probability of a pre-existing leak (for either Class 3a and 3b end states) of sufficient leak size to produce a large, early release.

6.2 ANALYSIS APPROACH

This section presents the steps involved in performing the ILRT extension risk assessment based on the methodology of the 2001 NEI Interim Guidance.

The nine analysis steps identified in the NEI Interim Guidance are:

1. Quantify the base line (nominal three year ILRT interval) risk in terms of frequency per reactor year for the EPRI accident classes of interest. Note that Classes 4, 5, and 6 are not affected by changes in ILRT test frequency. Therefore, these classes are not considered in this assessment methodology.
2. Determine the containment leakage rates for applicable cases, 3a and 3b.

3. Develop the baseline population dose (person-rem, from the plant IPE, or calculated based on leakage) for the applicable accident classes.
4. Determine the population dose rate (person-rem/year) by multiplying the dose calculated in step (3) by the associated frequency calculated in step (1).
5. Determine the change in probability of leakage detectable only by ILRT, and associated frequency for the new surveillance intervals of interest. Note that with increases in the ILRT surveillance interval, the size of the postulated leak path and the associated leakage rate are assumed not to change, however the probability of leakage detectable only by ILRT does increase.
6. Determine the population dose rate for the new surveillance intervals of interest.
7. Evaluate the risk impact (in terms of population dose rate and percentile change in population dose rate) for the interval extension cases.
8. Evaluate the risk impact in terms of LERF.
9. Evaluate the change in conditional containment failure probability.

Each of these steps are described in detail below. Note that this methodology builds upon the methodology of EPRI TR-104285. Therefore, most of the plant specific information necessary to perform the assessment using this methodology was presented in Sections 4 and 5 above (reference is made as necessary to the appropriate section in Section 4 or 5 for the development of the common information).

Step 1) Quantify the base line (nominal three year ILRT interval) risk in terms of frequency per reactor year for the EPRI accident classes of interest.

The baseline EPRI accident class frequencies used in the NEI methodology case are unchanged from those calculated in Sections 4 and

5 above, with the exceptions of the frequencies for EPRI categories 1 (No Containment Failure) and 3a (Small Containment Isolation Failures due to Liner Breach) and 3b (Large Containment Isolation Failures due to Liner Breach). As described above, the frequencies of leakages detectable only by ILRTs (EPRI Classes 3a and 3b) was revised. The NEI Interim Guidance included the results of additional, updated ILRT failure data (38 more industry tests conducted since 1/1/1995). Adding these to the NUREG-1493 data (144 ILRTs) resulted in a total population of 182 tests. One more failure was added (due to construction debris from a penetration modification), resulting in a total of 5 failures over these 182 tests. The Guidance recommended use of a mean frequency (5/182 = 0.027) for the Class 3a distribution, and recommended the use of a Jeffery's non-informative prior distribution for the Class 3b distribution:

$$\text{Failure Probability}_{3b} = (\text{Number of Failures} + ½) / (\text{Number of Tests} + 1)$$
$$= (0 + ½) / (182 + 1)$$
$$= 0.0027$$

Using these values, the calculation of the baseline Class 3a and 3b distributions was performed as follows:

For Unit 1:

CLASS_3a_FREQUENCY = 0.027 * 1.30E-5/year = 3.50E-7/year
CLASS_3b_FREQUENCY = 0.0027 * 1.30E-5/year = 3.56E-8/year

For Unit 2:

CLASS_3a_FREQUENCY = 0.027 * 1.81E-5/year = 4.89E-7/year
CLASS_3b_FREQUENCY = 0.0027 * 1.81E-5/year = 4.98E-8/year

In order to maintain the sum of the frequencies of the accident classes equal to the CDF, the NEI Interim Guidance specifies that the Class 1 frequency be adjusted for the Class 3 sequences. The baseline Class 1 frequency was determined as follows:

For Unit 1:

CLASS_1_FREQUENCY
= (PRA-quantified Class 1) - (Class 3a + Class 3b)
= 1.30E-5/yr – (3.50E-7+ 3.56E-8)/yr
= 1.26E-5/year

For Unit 2:

CLASS_1_FREQUENCY
= (PRA-quantified Class 1) - (Class 3a + Class 3b)
= 1.81E-5/yr – (4.89E-7+ 4.98E-8)/yr
= 1.76E-5/year

Table 6-1 below provides the Prairie Island accident class frequencies that were used in the application of the NEI Interim Guidance methodology.

Table 6-1
EPRI ACCIDENT CLASS FREQUENCIES
(Calculations Based on NEI Interim Guidance)

EPRI Accident Class	Description	EPRI Accident Class Frequency (per year)		Contribution to CDF (%)	
		Unit 1	Unit 2	Unit 1	Unit 2
1	No Containment Failure	1.26E-05	1.76E-05	78.20%	81.28%
2	Large Isolation Failures (Fail to Close)	2.31E-09	3.15E-09	0.01%	0.01%
3A	Small Isolation Failures (Liner Breach)	3.50E-07	4.89E-07	2.18%	2.26%
3B	Large Isolation Failures (Liner Breach)	3.56E-08	4.98E-08	0.22%	0.23%
4	Small Isolation Failures (Fail to Seal - Type B)	0.00E+00	0.00E+00	0.00%	0.00%
5	Small Isolation Failures (Fail to Seal - Type C)	0.00E+00	0.00E+00	0.00%	0.00%
6	Other Isolation Failures (e.g., dependent failures)	0.00E+00	0.00E+00	0.00%	0.00%
7	Failures induced by Phenomena (early and late)	4.38E-07	8.27E-07	2.72%	3.82%
8	Bypass (Interfacing Systems LOCA)	2.68E-06	2.68E-06	16.67%	12.39%
Total		1.61E-05	2.16E-05	100.0	100.0

Step 2: Determine the containment leakage rates for applicable cases, 3a and 3b.

Step 3: Develop the baseline population dose (person-rem, from the plant IPE, or calculated based on leakage) for the applicable accident classes.

Step 4: Determine the population dose rate (person-rem/year) by multiplying the dose calculated in step (3) by the associated frequency calculated in step (1).

Each of the calculations necessary for these steps were performed exactly as presented in Section 5.2 above. The resulting population dose rates for all accident classes are identical to that presented in Section 5.2, with the exception of Classes 1, 3a and 3b (the accident sequence frequencies of which were modified per the NEI guidance as described in Step 1 above). Table 6-2 provides the baseline results for the population dose rates by accident class.

Table 6-2
ANNUAL DOSE (PERSON-REM/YR) AS A FUNCTION OF ACCIDENT CLASS CHARACTERISTIC OF CONDITIONS FOR ILRT REQUIRED 3/10 YEARS
(Calculations Based on NEI Interim Guidance Methodology)

EPRI Accident Class	Description	EPRI Accident Class Frequency (per year)		Population Dose for Entire Region (person-rem)	Population Dose Rate for Entire Region (person-rem/yr)	
		Unit 1	Unit 2		Unit 1	Unit 2
1	No Containment Failure	1.26E-05	1.76E-05	8.97E+01	1.128E-03	1.577E-03
2	Large Isolation Failures (Fail to Close)	2.31E-09	3.15E-09	4.07E+06	9.409E-03	1.282E-02
3a	Small Isolation Failures (Liner Breach)	3.50E-07	4.89E-07	8.97E+02	3.139E-04	4.389E-04
3b	Large Isolation Failures (Liner Breach)	3.56E-08	4.98E-08	3.14E+03	1.118E-04	1.563E-04
4	Small Isolation Failures (Fail to Seal - Type B)	0.00E+00	0.00E+00	0	0.000E+00	0.000E+00
5	Small Isolation Failures (Fail to Seal - Type C)	0.00E+00	0.00E+00	0	0.000E+00	0.000E+00
6	Other Isolation Failures (e.g., dependent failures)	0.00E+00	0.00E+00	0	0.000E+00	0.000E+00
7	Failures induced by Phenomena (early and late)	4.38E-07	8.27E-07	2.16E+06	9.468E-01	1.789E+00
8	Bypass (Interfacing Systems LOCA)	2.68E-06	2.68E-06	1.24E+07	3.317E+01	3.318E+01
Total		**1.61E-05**	**2.16E-05**		**34.1317**	**34.9820**

The calculation of the baseline risk contribution from Class 3 (i.e., the Class affected by the ILRT interval change) was also done consistent with the method presented in Section 5.2. Based on the risk values from Table 6-2, the percent risk contribution ($\%Risk_{BASE}$) for Class 3 is as follows:

$$\%Risk_{BASE} = [(CLASS3a_{BASE} + CLASS\ 3b_{BASE}) / Total_{BASE}] \times 100$$

For Unit 1:

$CLASS3a_{BASE}$= Class 3a person-rem/year = 3.14E-04 person-rem/year [Table 6-2]

$CLASS3b_{BASE}$= Class 3b person-rem/year = 1.12E-04 person-rem/year

[Table 6-2]

$TOTAL_{BASE}$ = Total person-rem/yr for baseline interval
= 34.1317 person-rem/yr [Table 6-2]

$\%Risk_{BASE}$ = [(3.14E-04 + 1.12E-04)/34.1317] x 100
$\%Risk_{BASE}$ = 0.0012%

For Unit 2:

$CLASS3a_{BASE}$= Class 3a person-rem/year = 4.39E-04 person-rem/year [Table 6-2]

$CLASS3b_{BASE}$= Class 3b person-rem/year = 1.56E-04 person-rem/year [Table 6-2]

$TOTAL_{BASE}$ = Total person-rem/yr for baseline interval
= 34.9820 person-rem/yr [Table 6-2]

$\%Risk_{BASE}$ = [(4.39E-04 + 1.56E-04)/34.9820] x 100
$\%Risk_{BASE}$ = 0.0017%

Step 5) Determine the change in probability of leakage detectable only by ILRT, and associated frequency for the new surveillance intervals of interest. Note that with increases in the ILRT surveillance interval, the size of the postulated leak path and the associated leakage rate are assumed not to change, however the probability of leakage detectable only by ILRT does increase.

Step 6) Determine the population dose rate for the new surveillance intervals of interest.

Step 7) Evaluate the risk impact (in terms of population dose rate and percentile change in population dose rate) for the interval extension cases.

The increase in the Class 3 leakage frequencies for the surveillance intervals of interest (10 years and 15 years) were computed using the same methodology used in Section 5.3 above, except that the overall 10-year dose was calculated using an increased probability of an undetected leak of 333.3% (increased by a factor of 3.33), as opposed to the 10% value (factor of 1.1) used in the EPRI TR-105189 methodology. Likewise, the overall 15-year dose was calculated using an increased probability of an undetected leak of 500% (increased by a factor of 5.0). As described in the NEI Interim Guidance, increasing the test interval from 3 in 10 years to 1 in 10 years increases the average time that a leak (detectable only by an ILRT) goes undetected from 18 (3yrs/2) to 60 (10 yrs/2) months. This is a factor of 60/18=3.333. By the same logic, increasing the test interval from 3 in 10 years to 1 in 15 years increases the average time that a leak goes undetected from 18 (3yrs/2) to 90 (15 yrs/2) months, a factor of 90/18 = 5.0.

The increase in Class 7 frequency due to undetected corrosion-related leakage, calculated in Attachment 1, was included in the calculation as described in Section 5.3 above.

Tables 6-3 and 6-4 provide the results of the population dose rate calculations for the cases where the ILRT interval is extended to 10 years and 15 years, respectively.

Based on the risk values from Tables 6-3 and 6-4, the percent risk contribution for Class 3 over the two proposed ILRT extension intervals (%$Risk_{10}$ and %$Risk_{15}$) was calculated as follows:

For Unit 1:

$CLASS3a_{10}$ = Class 3a person-rem/year = 1.05E-3 person-rem/year [Table 6-3]

$CLASS\ 3b_{10}$ = Class 3b person-rem/year = 3.73E-04 person-rem/year [Table 6-3]

$CLASS3a_{15}$ = Class 3a person-rem/year = 1.57E-3 person-rem/year [Table 6-4]

$CLASS\ 3b_{15}$ = Class 3b person-rem/year = 5.59E-4 person-rem/year [Table 6-4]

$TOTAL_{10}$ = Total person-rem/yr for 10-year interval = 34.1326 person-rem/yr [Table 6-3]

$TOTAL_{15}$ = Total person-rem/yr for 15-year interval = 34.1333 person-rem/yr [Table 6-4]

$\%Risk_{10}$ = [(1.05E-3 + 3.73E-04) / 34.1326] x 100

$\%Risk_{10}$ = 0.0042%

$\%Risk_{15}$ = [(1.57E-3 + 5.59E-4) / 34.1333] x 100

$\%Risk_{15}$ = 0.0062%

For Unit 2:

$CLASS3a_{10}$ = Class 3a person-rem/year = 1.46E-3 person-rem/year [Table 6-3]

$CLASS\ 3b_{10}$ = Class 3b person-rem/year = 5.21E-4 person-rem/year [Table 6-3]

$CLASS3a_{15}$ = Class 3a person-rem/year = 2.19E-3 person-rem/year [Table 6-4]

$CLASS\ 3b_{15}$ = Class 3b person-rem/year = 7.82E-4 person-rem/year [Table 6-4]

$TOTAL_{10}$ = Total person-rem/yr for 10-year interval = 34.9833 person-rem/yr [Table 6-3]

$TOTAL_{15}$ = Total person-rem/yr for 15-year interval = 34.9842 person-rem/yr [Table 6-4]

$\%Risk_{10} = [(1.46E\text{-}3 + 5.21E\text{-}4) / 34.9833] \times 100$

$\%Risk_{10} = 0.0057\%$

$\%Risk_{15} = [(2.19E\text{-}3 + 7.82E\text{-}4) / 34.9842] \times 100$

$\%Risk_{15} = 0.0085\%$

Therefore, the Total Type A 10-year ILRT interval risk contribution of leakage, represented by Class 3 accident scenarios is 0.0042% [0.0057%] for the ILRT interval extension to 1 in 10 years, and 0.0062% [0.0085%] for the ILRT interval extension to 1 in 15 years.

The percent risk increase (Δ%Risk) for each ILRT extension case over the baseline case is as follows:

$\Delta\%Risk_{10} = [(Total_{10} - Total_{BASE}) / Total_{BASE}] \times 100.0$

$\Delta\%Risk_{15} = [(Total_{15} - Total_{BASE}) / Total_{BASE}] \times 100.0$

For Unit 1:

$TOTAL_{BASE}$ = Total person-rem/yr for baseline interval = 34.1317 person-rem/yr [Table 6-2]

$TOTAL_{10}$ = Total person-rem/yr for 10 yr ILRT interval = 34.1326 person-rem/yr [Table 6-3]

$TOTAL_{15}$ = Total person-rem/yr for 15 yr ILRT interval = 34.1333 person-rem/yr [Table 6-4]

$\Delta\%Risk_{10} = [(34.1326 - 34.1317) / 34.1317] \times 100.0$

$\Delta\%Risk_{10} = 0.0027\%$

$\Delta\%Risk_{15} = [(34.13333 - 34.1317) / 34.1317] \times 100.0$

$\Delta\%Risk_{15} = 0.0046\%$

For Unit 2:

$TOTAL_{BASE}$ = Total person-rem/yr for baseline interval = 34.9820 person-rem/yr [Table 6-2]

$TOTAL_{10}$ = Total person-rem/yr for 10 yr ILRT interval = 34.9833 person-rem/yr [Table 6-3]

$TOTAL_{15}$ = Total person-rem/yr for 15 yr ILRT interval = 34.9842 person-rem/yr [Table 6-4]

$\Delta\%Risk_{10} = [(34.9833 - 34.9820) / 34.9820] \times 100.0$

$\Delta\%Risk_{10} = 0.0036\%$

$\Delta\%Risk_{15} = [(34.9842 - 34.9820) / 34.9820] \times 100.0$

$\Delta\%Risk_{15} = 0.0063\%$

Therefore, the increase in risk contribution from the change to the already approved ten-year ILRT test interval from three-in-ten years to 1-in-ten-years is 0.0027% [0.0036%], while the increase in risk from the change to a 1-in-15 year test interval is 0.0046% [0.0063%].

Table 6-3
ANNUAL DOSE RATE (PERSON-REM/YR) AS A FUNCTION OF ACCIDENT CLASS CHARACTERISTIC OF CONDITIONS FOR ILRT REQUIRED EVERY 10 YEARS
(Calculations Based on NEI Interim Guidance)

EPRI Accident Class	Description	EPRI Accident Class Frequency (per year)		Population Dose for Entire Region (person-rem)	Population Dose Rate for Entire Region (person-rem/yr)	
		Unit 1	Unit 2		Unit 1	Unit 2
1	No Containment Failure	1.17E-05	1.63E-05	8.97E+01	1.047E-03	1.464E-03
2	Large Isolation Failures (Fail to Close)	2.31E-09	3.15E-09	4.07E+06	9.409E-03	1.282E-02
3a	Small Isolation Failures (Liner Breach)	1.17E-06	1.63E-06	8.97E+02	1.046E-03	1.463E-03
3b	Large Isolation Failures (Liner Breach)	1.19E-07	1.66E-07	3.14E+03	3.727E-04	5.211E-04
4	Small Isolation Failures (Fail to Seal - Type B)	0.00E+00	0.00E+00	0	0.000E+00	0.000E+00
5	Small Isolation Failures (Fail to Seal - Type C)	0.00E+00	0.00E+00	0	0.000E+00	0.000E+00
6	Other Isolation Failures (e.g., dependent failures)	0.00E+00	0.00E+00	0	0.000E+00	0.000E+00
7	Failures induced by Phenomena (early and late)	4.38E-07	8.27E-07	2.16E+06	9.468E-01	1.789E+00
8	Bypass (Interfacing Systems LOCA)	2.68E-06	2.68E-06	1.24E+07	3.317E+01	3.318E+01
Total		**1.61E-05**	**2.16E-05**		**34.1326**	**34.9833**

Table 6-4
ANNUAL DOSE RATE (PERSON-REM/YR) AS A FUNCTION OF ACCIDENT CLASS CHARACTERISTIC OF CONDITIONS FOR ILRT REQUIRED EVERY 15 YEARS
(Calculations Based on NEI Interim Guidance)

EPRI Accident Class	Description	EPRI Accident Class Frequency (per year)		Population Dose for Entire Region (person-rem)	Population Dose Rate for Entire Region (person-rem/yr)	
		Unit 1	Unit 2		Unit 1	Unit 2
1	No Containment Failure	1.10E-05	1.54E-05	8.97E+01	9.897E-04	1.384E-03
2	Large Isolation Failures (Fail to Close)	2.31E-09	3.15E-09	4.07E+06	9.409E-03	1.282E-02
3a	Small Isolation Failures (Liner Breach)	1.75E-06	2.45E-06	8.97E+02	1.569E-03	2.194E-03
3b	Large Isolation Failures (Liner Breach)	1.78E-07	2.49E-07	3.14E+03	5.590E-04	7.816E-04
4	Small Isolation Failures (Fail to Seal - Type B)	0.00E+00	0.00E+00	0	0.000E+00	0.000E+00
5	Small Isolation Failures (Fail to Seal - Type C)	0.00E+00	0.00E+00	0	0.000E+00	0.000E+00
6	Other Isolation Failures (e.g., dependent failures)	0.00E+00	0.00E+00	0	0.000E+00	0.000E+00
7	Failures induced by Phenomena (early and late)	4.38E-07	8.27E-07	2.16E+06	9.468E-01	1.789E+00
8	Bypass (Interfacing Systems LOCA)	2.68E-06	2.68E-06	1.24E+07	3.317E+01	3.318E+01
Total		**1.61E-05**	**2.16E-05**		**34.1333**	**34.9842**

Step 8) Evaluate the risk impact in terms of LERF.

<u>Baseline (3 Yr Test Interval) LERF</u>

From the Rev. 2.1 PRA results, the baseline LERF frequency is:

For Unit 1:

$LERF_{PRA}$ = 5.74E-07/year

$LERF_{BASE}$ = 5.74E-07/year

For Unit 2:

$LERF_{PRA}$ = 5.75E-07/year

$LERF_{BASE}$ = 5.75E-07/year

<u>LERF for 10-Yr Test Interval</u>

The LERF increase ($\Delta LERF_{10\text{-}BASE}$) due to a 10-year ILRT over the baseline is as follows:

$$\Delta LERF_{10\text{-}BASE} = CLASS3b_{10} - CLASS3b_{BASE}$$

The LERF ($LERF_{10}$) due to a 10-year ILRT is calculated as follows

$$LERF_{10} = LERF_{BASE} + \Delta LERF_{10\text{-}BASE}$$

For Unit 1:

$CLASS3b_{10}$ = 1.19E-07/year [Table 6-5]

$CLASS3b_{BASE}$ = 3.56E-08/year [Table 6-4]

$\Delta LERF_{10\text{-}BASE}$ = 1.19E-07/year – 3.56E-08/year = 8.31E-08/yr

$LERF_{10}$ = 5.74E-07/year + 8.31E-08/year = 6.57E-07/year

For Unit 2:

$CLASS3b_{10}$ = 1.66E-07/year [Table 6-5]

$CLASS3b_{BASE}$ = 4.98E-08/year [Table 6-4]

$\Delta LERF_{10\text{-}BASE}$ = 1.66E-07/year – 4.98E-07/year = 1.16E-07/yr

$LERF_{10}$ = 5.75E-07/year + 1.16E-07/year = 6.91E-07/year

LERF for 15-Yr Test Interval

The LERF increase ($\Delta LERF_{15\text{-}BASE}$) due to a 15-year ILRT over the baseline is as follows:

$$\Delta LERF_{15\text{-}BASE} = CLASS3b_{15} - CLASS3b_{BASE}$$

The LERF ($LERF_{15}$) due to a 15-year ILRT is calculated as follows

$$LERF_{15} = LERF_{BASE} + \Delta LERF_{15\text{-}BASE}$$

For Unit 1:

$CLASS3b_{15}$ = 1.78E-07/year [Table 6-6]
$CLASS3b_{BASE}$ = 3.56E-08/year [Table 6-4]

$\Delta LERF_{15\text{-}BASE}$ = 1.78E-07/year – 3.56E-08/year = 1.42E-07/year
$LERF_{15}$ = 5.74E-07/year + 1.42E-07/yr = 7.16E-07/year

For Unit 2:

$CLASS3b_{15}$ = 2.49E-07/year [Table 6-6]
$CLASS3b_{BASE}$ = 4.98E-08/year [Table 6-4]

$\Delta LERF_{15\text{-}BASE}$ = 2.49E-07/year – 4.98E-08/year = 1.99E-07/year
$LERF_{15}$ = 5.75E-07/year + 1.99E-07/year = 7.74E-07/year

The LERF increase ($\Delta LERF_{15\text{-}10}$) due to a 15-year ILRT over the 10-yr ILRT is as follows:

$$\Delta LERF_{15\text{-}10} = CLASS3b_{15} - CLASS3b_{10}$$

For Unit 1:

$CLASS3b_{15}$ = 1.78E-07/year [Table 6-6]

$CLASS3b_{10}$ = 1.19E-07/year [Table 6-5]

$\Delta LERF_{15\text{-}10}$ = 1.78E-07/year - 1.19E-07/year = 5.93E-08/year

For Unit 2:

$CLASS3b_{15}$ = 2.49E-07/year [Table 6-6]

$CLASS3b_{10}$ = 1.66E-07/year [Table 6-5]

$\Delta LERF_{15\text{-}10}$ = 2.49E-07/year - 1.66E-07/year = 8.30E-08/year

The calculated changes in LERF for these cases are slightly above the 1.0E-7/yr screening criterion in Reg. Guide 1.174. However, Reg. Guide 1.174, Section 2.2.4 states,

> "When the calculated increase in LERF is in the range of 10-7 per reactor year to 10-6 per reactor year, applications will be considered only if it can be reasonably shown that the total LERF is less than 10-5 per reactor year ..."

As the calculated absolute LERF values for both units are well below 1.0E-5/yr (in fact, all are below 1.0E-6/yr, even for the 15-year test interval case), the above condition has been clearly demonstrated to be met.

Step 9) *Evaluate the change in conditional containment failure probability.*

The assessment of conditional containment failure probability (CCFP) for each of the cases (base, 10-year ILRT interval extension, 15-year ILRT interval extension) is performed in a similar manner to that shown in Section 5.5 above, except that the Class 3a contribution was subtracted (Class 1 had already been reduced by the Class 3 sequences). Consistent with NEI Interim Guidance methodology, Class 3b is the only end state in which containment failure is assumed.

The CCFP calculation for the base case ($CCFP_{BASE}$) is shown below [23]:

$$CCFP_{BASE} = 1 - (\text{Intact Containment Frequency}_{BASE}/\text{Total CDF})$$
$$= \{1 - (\text{Class } 1_{BASE} + \text{Class } 3a_{BASE})/\text{CDF}\}*100$$

For Unit 1:

$$CCFP_{BASE} = \{1 - (1.26E\text{-}05 + 3.50E\text{-}07)/\ 1.61E\text{-}5\}*100$$
$$= 19.63\%$$

For Unit 2:

$$CCFP_{BASE} = \{1 - (1.76E\text{-}05 + 4.89E\text{-}07)/\ 2.16E\text{-}5\}*100$$
$$= 16.46\%$$

The CCFP calculation for the ILRT extension cases ($CCFP_{10}$ and $CCFP_{15}$) is performed in a similar manner:

$$CCFP_{10} = 1 - (\text{Intact Containment Frequency}_{10}/\text{Total CDF})$$
$$= \{1 - (\text{Class } 1_{10} + \text{Class } 3a_{10})/CDF\}*100$$

$$CCFP_{15} = 1 - (\text{Intact Containment Frequency}_{15}/\text{Total CDF})$$
$$= \{1 - (\text{Class } 1_{15} + \text{Class } 3a_{15})/CDF\}*100$$

For Unit 1:

$$CCFP_{10} = \{1 - (1.17E\text{-}05 + 1.17E\text{-}06)/ 1.61E\text{-}5\}*100$$
$$= 20.15\%$$

$$CCFP_{15} = \{1 - (1.10E\text{-}05 + 1.75E\text{-}06)/ 1.61E\text{-}5\}*100$$
$$= 20.51\%$$

For Unit 2:

$$CCFP_{10} = \{1 - (1.63E\text{-}05 + 1.63E\text{-}07)/ 2.16E\text{-}5\}*100$$
$$= 17.00\%$$

$$CCFP_{15} = \{1 - (1.54E\text{-}05 + 2.45E\text{-}07)/ 2.16E\text{-}5\}*100$$
$$= 17.38\%$$

The percent increase in CCFP ($\Delta\%CCFP_{BASE\text{-}10}$) due to a 10-year ILRT over the baseline is as follows:

$$\Delta\%CCFP_{10\text{-}BASE} = CCFP_{10} - CCFP_{BASE}$$

For Unit 1:

$$\Delta\%CCFP_{10\text{-}BASE} = 20.15\% - 19.63\%$$
$$= 0.52\%$$

For Unit 2:

$$\Delta\%CCFP_{10\text{-}BASE} = 17.00\% - 16.46\%$$
$$= 0.54\%$$

The percent increase in CCFP increase ($\Delta\%CCFP_{BASE\text{-}15}$) due to a 15-year ILRT over the baseline is as follows:

$$\Delta\%CCFP_{15\text{-}BASE} = CCFP_{15} - CCFP_{BASE}$$

For Unit 1:

$$\Delta\%CCFP_{15\text{-}BASE} = 20.51\% - 19.63\%$$
$$= 0.89\%$$

For Unit 2:

$$\Delta\%CCFP_{15\text{-}BASE} = 17.38\% - 16.46\%$$
$$= 0.92\%$$

The percent increase in CCFP increase ($\Delta\%CCFP_{15\text{-}10}$) due to a 15-year ILRT over the 10-year ILRT is as follows:

$$\Delta\%CCFP_{15\text{-}10} = CCFP_{15} - CCFP_{10}$$

For Unit 1:

$$\Delta\%CCFP_{15\text{-}10} = 20.51\% - 20.15\%$$
$$= 0.36\%$$

For Unit 2:

$$\Delta\%CCFP_{15\text{-}10} = 17.38\% - 17.00\%$$
$$= 0.38\%$$

This change in CCFP of less than 1% is judged to be insignificant and reflects sufficient defense-in-depth.

6.3 RESULTS SUMMARY

The following is a brief summary of some of the key aspects of the ILRT test interval extension risk analysis (as calculated in Section 6 – NEI Interim Guidance Methodology):

1. The baseline risk contribution (person-rem/yr) associated with containment leakage affected by the ILRT and represented by Class 3 accident scenarios is 0.0012% [0.0017%] of the total risk.

2. When the ILRT interval is 10 years, the risk contribution of leakage (person-rem/yr) represented by Class 3 accident scenarios is increased insignificantly (contribution is increased to 0.0042% [0.0057%] of the total risk).

3. The total integrated increase in risk contribution from reducing the ILRT test frequency from 3-per-10-year (baseline) frequency to once-per-10 years is near zero (0.0027% [0.0036%] to the nearest 1/100th of 1 percent).

4. When the ILRT interval is 15 years, the risk contribution of leakage (person-rem/yr) represented by Class 3 accident scenarios is increased insignificantly (contribution is 0.0062% [0.0085%] of the total risk).

5. The total integrated increase in risk contribution from reducing the ILRT test frequency from 3-per-10-year (baseline) frequency to once-per-15 years is insignificant (0.0046% [0.0063%]).

6. There is no change in the at-power CDF associated with the ILRT extension. Therefore, this is within the Reg. Guide 1.174 acceptance

guidelines.

7. The risk increase in LERF from the original 3-in-10 years test frequency to once-per-10 years is 8.31E-08/yr [1.16E-07/yr]. The Unit 2 LERF is slightly higher than the screening acceptance guidelines in Reg. Guide 1.174. However, the total LERF for the 10-year interval remains well within the acceptance guidelines in Reg. Guide 1.174, Section 2.2.4 (less than 1.0E-05/yr).

8. The risk increase in LERF from the original 3-in-10 years test frequency to once-per-15 years is 1.42E-07/yr [1.99E-07/yr]. This is slightly higher than the screening acceptance guidelines in Reg. Guide 1.174. However, the total LERF for the 15-year interval remains well within the acceptance guidelines in Reg. Guide 1.174, Section 2.2.4 (less than 1.0E-05/yr).

9. The risk increase in LERF from reducing the ILRT test frequency from once-per-10 years to one-per-15 years is 5.93E-08/yr [8.30E-08/yr]. This is within the acceptance guidelines in Reg. Guide 1.174.

10. The change in CCFP of less than 1% [less than 1%] for both cases, reducing test frequency to either once-per-10 or once-per-15 years, is judged to be insignificant and reflects sufficient defense-in-depth.

Other significant results are summarized in Table 6-5 below.

Table 6-5
SUMMARY OF RISK IMPACT ON TYPE A ILRT TEST FREQUENCY
(Calculations Based on NEI Interim Guidance)

Risk Metric	Risk Impact (Baseline)		Risk Impact (10-years)		Risk Impact (15-years)	
	Unit 1	Unit 2	Unit 1	Unit 2	Unit 1	Unit 2
Class 3a and 3b Risk Contribution	0.0012% of total integrated value 4.26E-04 person-rem/yr	0.0017% of total integrated value 5.95E-04 person-rem/yr	0.0042% of total integrated value 1.42E-3 person-rem/yr	0.0057% of total integrated value 1.98E-3 person-rem/yr	0.0062% of total integrated value 2.13E-3 person-rem/yr	0.0085% of total integrated value 2.98E-3 person-rem/yr
Total Integrated Risk	34.1317 person-rem/year	34.9820 person-rem/year	34.1326 person-rem/year	34.9833 person-rem/year	34.1333 person-rem/year	34.9842 person-rem/year
Percent Increase in Integrated Risk over Baseline	N/A	N/A	0.0027%	0.0036%	0.0046%	0.0063%
Increase in LERF over Baseline	N/A	N/A	8.31E-08/yr	1.16E-07/yr	1.42E-07/yr	1.99E-07/yr
Percent Increase in CCFP over Baseline	N/A	N/A	0.5168%	0.5371%	0.8859%	0.9207%

Section 7

APPLICATION OF DRAFT EPRI TR-1009325 METHODOLOGY

7.1 SUMMARY OF METHODOLOGY

EPRI TR-1009325 [23] (still in draft form) is an update to EPRI TR-104285 [2] (which, in turn, was built upon the guidance of NUREG-1493 [4]) that includes the changes to the methodology included in the NEI Interim Guidance [23], plus additional enhancements that were obtained through an expert elicitation process. In addition, the methodology incorporates the results of NRC comments on various industry ILRT interval extension submittals. The expert elicitation was aimed at reducing the conservatisms associated with the various containment leakage methodologies available that were found to provide widely differing risk results when applied to the same problem.

The enhancements in TR-1009325 are generally in two areas:

1. Definition (in terms of the required resulting L_a leakage term) of the assumed containment leakage size that could lead to a large, early release (LERF), ie., EPRI accident Class 3b. Whereas previous submittals assumed a very conservative leakage term (35 L_a) would have the potential to result in a LERF event, the methodology provides a basis for using a (still conservative) value of 100 L_a instead. For the smaller pre-existing leak (accident Class 3a) size, the previously used conservative value of 10 L_a was retained by the methodology.
2. Development of specific probabilities for pre-existing containment leakage sizes. This was done through the expert elicitation process. EPRI TR-1009325 states that this method provides a considerable improvement over the use of non-informative priors (as has been done in previous licensee submittals based on application of the previous EPRI TR-104285

methodology).

3. Consideration of the potential risk benefits associated with other containment inspections (non-ILRT) and potential indirect containment monitoring techniques that would provide indications of a containment leak (determination of the probability of leakage detection over an increased ILRT interval, again through use of the expert elicitation process).

Application of the EPRI TR-1009325 methodology generally produces results that indicate lower population dose risk than previous methodologies due to the reduction in the conservatisms noted above.

7.2 ANALYSIS APPROACH

Implementation of the methodology of EPRI TR-1009325 is very similar to the implementation of the NEI Interim Guidance discussed in Section 6.2 (the steps required for the analysis identified in TR-1009325 are identical with those presented in the NEI Interim Guidance). The practical differences between the two analyses lies in the inputs used for determining the leak size requirements for LERF categorization (EPRI Class 3b), and in the probability values applied to the assumed undetected leakage categories. Therefore, in this section, the calculation discussion focuses on the changes in these inputs only. The calculation details followed are identical to those shown for the NEI Interim Guidance (Section 6.2). The presentation of results in Section 7.3 mirrors that provided for the other two methodologies.

Step 1) Quantify the base line (nominal three year ILRT interval) risk in terms of frequency per reactor year for the EPRI accident classes of interest.

Step 1 was quantified as described in Section 6.3 above, except in the leakage size and probabilities determined for Class 3a and Class 3 b accident sequences.

Utility ILRT extension submittals based on previous methodologies (EPRI TR-104285, 2001 NEI Interim Guidance) relied upon statistical failure data updates using non-informative priors in order to determine the probability values for containment leakage identifiable only through ILRTs (particularly Class 3b). As the risk results are sensitive to the 3b values, the choice of statistical methodology applied was seen to produce a somewhat wide range of risk results. EPRI TR-1009325 used expert elicitation to develop a relationship between the size of potential containment leakage pathways, expressed as L_a, and the probability of occurrence. This methodology was seen as a considerable improvement over the use of non-informative priors.

A summary of the final results of the statistical analysis of the expert elicitation (leak size vs. probability) are given in Table 6-1 of EPRI TR-1009325. As stated in Section 7.1 above, for Class 3 leakage scenarios, the EPRI TR-1009325 methodology specifies the use of 10 L_a as a conservative upper bound leakage size for Class 3a sequences, and 100 L_a as a conservative upper bound leakage size for Class 3b sequences. From Table 6-1, the mean probability of occurrence for a 10 L_a (Class 3a) leak is 3.88E-03, and the mean probability of occurrence for a 100 L_a (Class 3b) leak is 2.47E-04. Using these values, the calculation of the baseline Class 3a and 3b distributions was performed as follows:

For Unit 1:

CLASS_3a_FREQUENCY = 3.88E-03 * 1.30E-5/year = 5.03E-8/year
CLASS_3b_FREQUENCY = 2.47E-04 * 1.30E-5/year = 3.20E-9/year

For Unit 2:

CLASS_3a_FREQUENCY = 3.88E-03 * 1.81E-5/year = 7.03E-8/year
CLASS_3b_FREQUENCY = 2.47E-04 * 1.81E-5/year = 4.47E-9/year

These values are about an order of magnitude lower than the values calculated in Sections 5.1 (TR-104285 methodology) and 6.2 (NEI Interim Guidance methodology) above.

The remainder of the Step 1 calculation follows the same process as that presented in Section 6.2 above. Table 7-1 below provides the Prairie Island accident class frequencies that were used in the application of the EPRI TR-1009325 methodology.

Steps 2 – 9)

The process followed to complete Steps 2 – 9 for the EPRI TR-1009325 methodology was the same as that presented in Section 6.2 above. Tables 7-1 through 7-4 below provide the interim results of the EPRI TR-1009325 methodology.

Table 7-1
EPRI ACCIDENT CLASS FREQUENCIES
(based on EPRI TR-1009325 Methodology)

EPRI Accident Class	Description	EPRI Accident Class Frequency (per year)		Contribution to CDF (%)	
		Unit 1	Unit 2	Unit 1	Unit 2
1	No Containment Failure	1.29E-05	1.80E-05	80.26%	83.42%
2	Large Isolation Failures (Fail to Close)	2.31E-09	3.15E-09	0.01%	0.01%
3A	Small Isolation Failures (Liner Breach)	5.03E-08	7.03E-08	0.31%	0.33%
3B	Large Isolation Failures (Liner Breach)	3.20E-09	4.47E-09	0.02%	0.02%
4	Small Isolation Failures (Fail to Seal - Type B)	0.00E+00	0.00E+00	0.00%	0.00%
5	Small Isolation Failures (Fail to Seal - Type C)	0.00E+00	0.00E+00	0.00%	0.00%
6	Other Isolation Failures (e.g., dependent failures)	0.00E+00	0.00E+00	0.00%	0.00%
7	Failures induced by Phenomena (early and late)	4.38E-07	8.27E-07	2.72%	3.82%
8	Bypass (Interfacing Systems LOCA)	2.68E-06	2.68E-06	16.67%	12.39%
Total		1.61E-05	2.16E-05	100.0	100.0

Table 7-2
ANNUAL DOSE (PERSON-REM/YR) AS A FUNCTION OF ACCIDENT CLASS
CHARACTERISTIC OF CONDITIONS FOR ILRT REQUIRED 3/10 YEARS
(Calculations Based on EPRI TR-1009325 Methodology)

EPRI Accident Class	Description	EPRI Accident Class Frequency (per year)		Population Dose for Entire Region (person-rem)	Population Dose Rate for Entire Region (person-rem/yr)	
		Unit 1	Unit 2		Unit 1	Unit 2
1	No Containment Failure	1.29E-05	1.80E-05	8.97E+01	1.158E-03	1.619E-03
2	Large Isolation Failures (Fail to Close)	2.31E-09	3.15E-09	4.07E+06	9.409E-03	1.282E-02
3a	Small Isolation Failures (Liner Breach)	5.03E-08	7.03E-08	8.97E+02	4.511E-05	6.307E-05
3b	Large Isolation Failures (Liner Breach)	3.20E-09	4.47E-09	3.14E+03	2.872E-05	4.015E-05
4	Small Isolation Failures (Fail to Seal - Type B)	0.00E+00	0.00E+00	0	0.000E+00	0.000E+00
5	Small Isolation Failures (Fail to Seal - Type C)	0.00E+00	0.00E+00	0	0.000E+00	0.000E+00
6	Other Isolation Failures (e.g., dependent failures)	0.00E+00	0.00E+00	0	0.000E+00	0.000E+00
7	Failures induced by Phenomena (early and late)	4.38E-07	8.27E-07	2.16E+06	9.468E-01	1.789E+00
8	Bypass (Interfacing Systems LOCA)	2.68E-06	2.68E-06	1.24E+07	3.317E+01	3.318E+01
Total		1.61E-05	2.16E-05		34.1314	34.9816

Table 7-3
ANNUAL DOSE RATE (PERSON-REM/YR) AS A FUNCTION OF ACCIDENT CLASS CHARACTERISTIC OF CONDITIONS FOR ILRT REQUIRED EVERY 10 YEARS
(Calculations Based on EPRI TR-1009325 Methodology)

EPRI Accident Class	Description	EPRI Accident Class Frequency (per year)		Population Dose for Entire Region (person-rem)	Population Dose Rate for Entire Region (person-rem/yr)	
		Unit 1	Unit 2		Unit 1	Unit 2
1	No Containment Failure	1.28E-05	1.79E-05	8.97E+01	1.147E-03	1.603E-03
2	Large Isolation Failures (Fail to Close)	2.31E-09	3.15E-09	4.07E+06	9.409E-03	1.282E-02
3a	Small Isolation Failures (Liner Breach)	1.68E-07	2.34E-07	8.97E+02	1.504E-04	2.102E-04
3b	Large Isolation Failures (Liner Breach)	1.07E-08	1.49E-08	3.14E+03	9.574E-05	1.339E-04
4	Small Isolation Failures (Fail to Seal - Type B)	0.00E+00	0.00E+00	0	0.000E+00	0.000E+00
5	Small Isolation Failures (Fail to Seal - Type C)	0.00E+00	0.00E+00	0	0.000E+00	0.000E+00
6	Other Isolation Failures (e.g., dependent failures)	0.00E+00	0.00E+00	0	0.000E+00	0.000E+00
7	Failures induced by Phenomena (early and late)	4.38E-07	8.27E-07	2.16E+06	9.468E-01	1.789E+00
8	Bypass (Interfacing Systems LOCA)	2.68E-06	2.68E-06	1.24E+07	3.317E+01	3.318E+01
Total		**1.61E-05**	**2.16E-05**		**34.1315**	**34.9818**

Table 7-4
ANNUAL DOSE RATE (PERSON-REM/YR) AS A FUNCTION OF ACCIDENT CLASS CHARACTERISTIC OF CONDITIONS FOR ILRT REQUIRED EVERY 15 YEARS
(Calculations Based on EPRI TR-1009325 Methodology)

EPRI Accident Class	Description	EPRI Accident Class Frequency (per year)		Population Dose for Entire Region (person-rem)	Population Dose Rate for Entire Region (person-rem/yr)	
		Unit 1	Unit 2		Unit 1	Unit 2
1	No Containment Failure	1.27E-05	1.77E-05	8.97E+01	1.139E-03	1.592E-03
2	Large Isolation Failures (Fail to Close)	2.31E-09	3.15E-09	4.07E+06	9.409E-03	1.282E-02
3a	Small Isolation Failures (Liner Breach)	2.51E-07	3.51E-07	8.97E+02	2.255E-04	3.154E-04
3b	Large Isolation Failures (Liner Breach)	1.60E-08	2.24E-08	3.14E+03	1.436E-04	2.008E-04
4	Small Isolation Failures (Fail to Seal - Type B)	0.00E+00	0.00E+00	0	0.000E+00	0.000E+00
5	Small Isolation Failures (Fail to Seal - Type C)	0.00E+00	0.00E+00	0	0.000E+00	0.000E+00
6	Other Isolation Failures (e.g., dependent failures)	0.00E+00	0.00E+00	0	0.000E+00	0.000E+00
7	Failures induced by Phenomena (early and late)	4.38E-07	8.27E-07	2.16E+06	9.468E-01	1.789E+00
8	Bypass (Interfacing Systems LOCA)	2.68E-06	2.68E-06	1.24E+07	3.317E+01	3.318E+01
Total		1.61E-05	2.16E-05		34.1316	34.9820

7.3 RESULTS SUMMARY

The following is a brief summary of some of the key aspects of the ILRT test interval extension risk analysis (as calculated in Section 7 – EPRI TR-1009325 Methodology):

1. The baseline risk contribution (person-rem/yr) associated with containment leakage affected by the ILRT and represented by Class 3 accident scenarios is 0.0002% [0.0003%] of the total risk.

2. When the ILRT interval is 10 years, the risk contribution of leakage (person-rem/yr) represented by Class 3 accident scenarios is increased insignificantly (contribution is increased to 0.0007% [0.0010%] of the total risk).

3. The total integrated increase in risk contribution from reducing the ILRT test frequency from 3-per-10-year (baseline) frequency to once-per-10 years is near zero (0.0005% [0.0006%].

4. When the ILRT interval is 15 years, the risk contribution of leakage (person-rem/yr) represented by Class 3 accident scenarios is increased insignificantly (contribution remains 0.0011% [0.0015%] of the total risk).

5. The total integrated increase in risk contribution from reducing the ILRT test frequency from 3-per-10-year (baseline) frequency to once-per-15 years is insignificant (0.0008% [0.0010%]).

6. There is no change in the at-power CDF associated with the ILRT extension. Therefore, this is within the Reg. Guide 1.174 acceptance guidelines.

7. The risk increase in LERF from the original 3-in-10 years test frequency to once-per-10 years is 7.47E-09/yr [1.04E-08/yr]. This is within the acceptance guidelines in Reg. Guide 1.174.

8. The risk increase in LERF from the original 3-in-10 years test frequency to once-per-15 years is 1.28E-08/yr [1.79E-08/yr]. This is within the acceptance guidelines in Reg. Guide 1.174.

9. The risk increase in LERF from reducing the ILRT test frequency from once-per-10 years to one-per-15 years is 5.33E-09/yr [7.46E-09/yr]. This is within the acceptance guidelines in Reg. Guide 1.174.

10. The change in CCFP of less than 1% [less than 1%] for both cases, reducing test frequency to either once-per-10 or once-per-15 years, is judged to be insignificant and reflects sufficient defense-in-depth.

Other significant results are summarized in Table 7-5 below.

Table 7-5
SUMMARY OF RISK IMPACT OF TYPE A ILRT TEST FREQUENCIES
(Calculations Based on EPRI TR-1009325 Methodology)

Risk Metric	**Risk Impact (Baseline)**		**Risk Impact (10-years)**		**Risk Impact (15-years)**	
	Unit 1	Unit 2	Unit 1	Unit 2	Unit 1	Unit 2
Class 3a and 3b Risk Contribution	0.0002% of total integrated value 7.38E-05 person-rem/yr	0.0003% of total integrated value 1.03E-04 person-rem/yr	0.0007% of total integrated value 2.46E-04 person-rem/yr	0.0010% of total integrated value 3.44E-04 person-rem/yr	0.0011% of total integrated value 3.69E-04 person-rem/yr	0.0015% of total integrated value 5.16E-04 person-rem/yr
Total Integrated Risk	34.1314 person-rem/year	34.9816 person-rem/year	34.1315 person-rem/year	34.9818 person-rem/year	34.1316 person-rem/year	34.9820 person-rem/year
Percent Increase in Integrated Risk over Baseline	N/A	N/A	0.0005%	0.0006%	0.0008%	0.0011%
Increase in LERF over Baseline	N/A	N/A	7.47E-09/yr	1.04E-08/yr	1.28E-08/yr	1.79E-08/yr
Percent Increase in CCFP over Baseline	N/A	N/A	0.0465%	0.0483%	0.0797%	0.0828%

Section 8
CONCLUSIONS

This section provides the principal conclusions of the ILRT test interval extension risk assessments as reported for the following:

- Previous generic risk assessment by the NRC
- Plant Specific Prairie Island risk assessment for the at-power case, performed using three available methodologies (EPRI TR-104285, NEI Interim Guidance, and EPRI TR-1009325)
- General conclusions regarding the beneficial effects on shutdown risk

8.1 PREVIOUS ASSESSMENTS

The NRC in NUREG-1493 has previously concluded that:

- Reducing the frequency of Type A tests (ILRTs) from the current three per 10 years to one per 20 years was found to lead to an imperceptible increase in risk. The estimated increase in risk is very small because ILRTs identify only a few potential containment leakage paths that cannot be identified by Type B and C testing, and the leaks that have been found by Type A tests have been only marginally above existing requirements.
- Given the insensitivity of risk to containment leakage rate and the small fraction of leakage paths detected solely by Type A testing, increasing the interval between integrated leakage-rate tests is possible with minimal impact on public risk. The impact of relaxing the ILRT frequency beyond one in 20 years has not been evaluated. Beyond testing the performance of containment penetrations, ILRTs also test the integrity of the containment liner.

8.2 PRAIRIE ISLAND SPECIFIC RISK RESULTS

The findings for Prairie Island confirm the general findings of previous studies on a plant specific basis, including severe accident category frequencies, the containment failure modes, the Technical Specification allowed leakage, and the local population surrounding the Prairie Island station. Based on the results from Sections 5 through 7, the following conclusions regarding the assessment of the plant risk are associated with extending the Type A ILRT test from ten years to fifteen years:

- There is no change in the at-power CDF associated with the ILRT test interval extension. Therefore, this is within the Reg. Guide 1.174 acceptance guidelines.

- Reg. Guide 1.174 provides guidance for determining the risk impact of plant-specific changes to the licensing basis. Reg. Guide 1.174 defines very small changes in risk as resulting in increases of CDF below 10^{-6}/yr and increases in LERF below 10^{-7}/yr. Since the ILRT does not impact CDF, the relevant criterion is LERF. The increase in LERF resulting from a change in the Type A ILRT test frequency from once-per-ten-years to once-per-fifteen years is between 5.33E-9/yr [7.46E-9/yr] and 5.93E-08/yr [8.30E-8/yr]. Therefore, increasing the ILRT interval from 10 to 15 years is considered to result in a very small change to the Prairie Island risk profile.

- The proposed change in the Type A test frequency (from once-per-ten-years to once-per-fifteen-years) increases the total integrated plant risk by significantly less than 1% for both units. Therefore, the risk impact of this change, when compared to other severe accident risks, is negligible.

- The change in Conditional Containment Failure Probability (CCFP) of less than 1% for both units is judged to be insignificant and reflects sufficient defense-in-depth.

8.3 SENSITIVITY ANALYSIS FOR USE OF EPRI REPRESENTATIVE PLANT CONSEQUENCE MEASURES

As stated in Section 4.2 above, the EPRI "representative plant" dose results from Table 4 of EPRI TR-104285 [2] were used for this analysis in lieu of plant-specific Level 3 consequence measures, which are not currently available for Prairie Island. From Section 4.2, footnote 4 of EPRI TR-104285, factors such as plant power rating and demographics can impact the results of the offsite dose calculations for a particular site relative to the results for the NUREG-1150 plants. The footnote concludes with "However, in as much as the comparison is made relative to a baseline, the differences not considered in this analysis, would not impact the conclusions drawn."

To ensure that the conclusions from the Prairie Island analysis are not impacted by the use of the representative plant dose data, an analysis of the sensitivity of the results to the dose rates used was performed. In the analysis, the effects on offsite dose for the various accident classes are assumed to vary roughly linearly with differences in plant power level and demographics (surrounding region population). A factor of 10 increase was applied to doses for all accident classes in the study (those doses applied in Table 4.2-2) for each of the three methodologies. None of the key output metrics (%Risk, delta-%Risk, LERF, delta-LERF, CCFP, or delta-CCFP) were observed to increase by more than 0.1% (only the %Risk measures have any measurable sensitivity to the dose values used). Therefore, it is concluded that the use of the EPRI representative plant doses was appropriate as a substitute for Prairie Island plant-specific offsite consequence measures for this analysis.

Note that Prairie Island is a 2-loop Westinghouse PWR, whereas the Surry plant (NUREG-1150) is a 3-loop PWR, and thus has a significantly lower power rating than does Surry and a lower rating than would an "average PWR", as most industry PWRs are 3-loop or 4-loop plants. Also, although not investigated in detail for this analysis, the surrounding population demographics for Prairie Island are not expected to be any higher than they would be for an "average PWR". Therefore, increasing the dose results used for this sensitivity analysis by a factor of 10 is considered to be conservative for Prairie Island.

Tables 8-1 and 8-2 below summarize the Prairie Island-specific Unit 1 and Unit 2 results of this risk evaluation, respectively.

Table 8-1

UNIT 1 SUMMARY OF RISK IMPACT OF VARIOUS TYPE A ILRT TEST FREQUENCIES

(Summary by Methodology)

Risk Metric	Risk Impact (Baseline)			Risk Impact (10-years)			Risk Impact (15-years)		
Calculation Methodology	EPRI TR-104285	NEI Interim Guidance	EPRI TR-1009325	EPRI TR-104285	NEI Interim Guidance	EPRI TR-1009325	EPRI TR-104285	NEI Interim Guidance	EPRI TR-1009325
Class 3a and 3b Risk Contribution	0.0058% of total integrated value 1.98E-3 person-rem/yr	0.0012% of total integrated value 4.26E-04 person-rem/yr	0.0002% of total integrated value 7.38E-05 person-rem/yr	0.0064% of total integrated value 2.18E-3 person-rem/yr	0.0042% of total integrated value 1.42E-3 person-rem/yr	0.0007% of total integrated value 2.46E-04 person-rem/yr	0.0067% of total integrated value 2.28E-3 person-rem/yr	0.0062% of total integrated value 2.13E-3 person-rem/yr	0.0011% of total integrated value 3.69E-04 person-rem/yr
Total Integrated Risk	34.1332 person-rem/year	34.1317 person-rem/year	34.1314 person-rem/year	34.1334 person-rem/year	34.1326 person-rem/year	34.1315 person-rem/year	34.1334 person-rem/year	34.1333 person-rem/year	34.1316 person-rem/year
Percent Increase in Integrated Risk over Baseline	N/A	N/A	N/A	0.0005%	0.0027%	0.0005%	0.0008%	0.0046%	0.0008%
Increase in LERF over Baseline	N/A	N/A	N/A	3.39E-08/yr	8.31E-08/yr	7.47E-09/yr	5.07E-08/yr	1.42E-07/yr	1.28E-08/yr
Percent Increase in CCFP over Baseline	N/A	N/A	N/A	0.851%	0.5168%	0.0465%	1.28%	0.8859%	0.0797%

Table 8-2

UNIT 2 SUMMARY OF RISK IMPACT OF VARIOUS TYPE A ILRT TEST FREQUENCIES

(Summary by Methodology)

Risk Metric	Risk Impact (Baseline)			Risk Impact (10-years)			Risk Impact (15-years)		
Calculation Methodology	EPRI TR-104285	NEI Interim Guidance	EPRI TR-1009325	EPRI TR-104285	NEI Interim Guidance	EPRI TR-1009325	EPRI TR-104285	NEI Interim Guidance	EPRI TR-1009325
Class 3a and 3b Risk Contribution	0.0076% of total integrated value 2.67E-3 person-rem/yr	0.0017% of total integrated value 5.95E-04 person-rem/yr	0.0003% of total integrated value 1.03E-04 person-rem/yr	0.0084% of total integrated value 2.94E-3 person-rem/yr	0.0057% of total integrated value 1.98E-3 person-rem/yr	0.0010% of total integrated value 3.44E-04 person-rem/yr	0.0084% of total integrated value 3.07E-3 person-rem/yr	0.0085% of total integrated value 2.98E-3 persón-rem/yr	0.0015% of total integrated value 5.16E-04 person-rem/yr
Total Integrated Risk	34.9840 person-rem/year	34.9820 person-rem/year	34.9816 person-rem/year	34.9843 person-rem/year	34.9833 person-rem/year	34.9818 person-rem/year	34.9844 person-rem/year	34.9842 person-rem/year	34.9820 person-rem/year
Percent Increase in Integrated Risk over Baseline	N/A	N/A	N/A	0.0007%	0.0036%	0.0006%	0.0011%	0.0063%	0.0011%
Increase in LERF over Baseline	N/A	N/A	N/A	4.55E-08/yr	1.16E-07/yr	1.04E-08/yr	6.83E-08/yr	1.99E-07/yr	1.79E-08/yr
Percent Increase in CCFP over Baseline	N/A	N/A	N/A	0.850%	0.5371%	0.0483%	1.28%	0.9207%	0.0828%

8.4 RISK TRADE-OFF

The performance of an ILRT occurs during plant shutdown and introduces some small residual risk. An EPRI study of operating experience events associated with the performance of ILRTs has indicated that there are real shutdown risk impacts associated with the setup and performance of the ILRT during shutdown operation [10]. While these risks have not been quantified for Prairie Island, it is judged that there is a positive (yet un-quantified) safety benefit associated with the avoidance of frequent ILRTs.

The safety benefits relate to the avoidance of plant conditions and alignments associated with the ILRT which place the plant in a less safe condition leading to events related to drain down or loss of shutdown cooling. Therefore, while the focus of this evaluation has been on the negative aspects, or increased risk, associated with the ILRT test interval extension, there are, in fact, positive safety benefits that reduce the already small risk associated with the extension of the ILRT test interval.

Section 9
REFERENCES

1) *Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J*, NEI 94-01, July 1995.

2) *Risk Impact Assessment of Revised Containment Leak Rate Testing Intervals*, EPRI, Palo Alto, CA EPRI TR-104285, August 1994.

3) *An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis,* Regulatory Guide 1.174, July 1998.

4) *Performance-Based Containment Leak-Test Program*, NUREG-1493, September 1995.

5) *Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals,* EPRI TR-1009325, Final Report, December 2003.

6) *Technical Findings and Regulatory Analysis for Genetic Study Issue II.e.43 'Containment Integrity Check',* NUREG-1273, April 1988.

7) *Impact of Containment Building Leakage on LWR Accident Risk,* Oak Ridge National Laboratory, NUREG/CR-3539, ORNL/TM-8964, April 1984.

8) *Reliability Analysis of Containment Isolation Systems,* Pacific Northwest Laboratory, NUREG/CR-4220, PNL-5432, June 1985.

9) *Review of Light Water Reactor Regulatory Requirements,* Pacific Northwest Laboratory, NUREG/CR-4330, PNL-5809, Vol. 2, June 1986.

10) *Shutdown Risk Impact Assessment for Extended Containment Leakage Testing Intervals Utilizing ORAM™*, EPRI, Palo Alto, CA TR-105189, Final Report, May 1995.

11) *Individual Plant Examination Peach Bottom Atomic Power Station Units 2 and 3,* Volumes 1 and 2 Philadelphia Electric Company, 1992.

12) *ALWR Severe Accident Dose Analysis,* DE-ACOG-87RL11313, March 1989.

13) Patrick D. T. O'Connor, *Practical Reliability Engineering,* John Wiley & Sons, 2nd Edition, 1985.

14) Letter from R. J. Barrett (Entergy) to U.S. Nuclear Regulatory Commission, IPN-01-007, dated January 16, 2001.

15) Letter from J. A. Hutton (Exelon, Peach Bottom) to U.S. Nuclear Regulatory Commission, Docket No. 50-278, License No. DDPR-56, LAR 01-00430, dated May 30, 2001.

16) Letter from D. E. Young (Florida Power) to U.S. Nuclear Regulatory Commission, 3F0401-11, dated April 25, 2001.

17) Regulatory Guide 1.174, *An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis,* Revision 1, November 2002.

18) Burns, T. J., *Impact of Containment Building Leakage on LWR Accident Risk,* Oak Ridge National Laboratory, NUREG/CR-3539, April 1984.

19) United States Nuclear Regulatory Commission, Reactor Safety Study, WASH-1400, October 1975.

20) Letter from SNC (H. L. Summer, Jr.) to USNRC dated July 26, 2000.

21) United States Nuclear Regulatory Commission, Indian Point Nuclear Generating Unit No. 3 – Issuance of Amendment Re: Frequency of Performance-Based Leakage Rate Testing (TAC No. MB0178), April 17, 2001.

22) NUREG-1150, "Severe Accident Risks: An Assessment for Five Nuclear Power Plants", Vol. 1, Final Report, December, 1990.

23) J. Haugh, J. Gisclon, W. Parkinson, K. Canavan, "Interim Guidance for Performing Risk Impact Assessments in Support of One-Time Extensions for Containment Integrated Leak Rate Test Intervals", Rev. 4, EPRI, Nov. 2001.

24) Prairie Island Procedure H19, "Containment Leak Rate Testing", Rev. 10.

25) Patrick D.T. O'Connor, *"Practical Reliability Engineering"*, John Wiley & Sons, 2nd Edition, 1985.

26) Prairie Island PRA Calculation V.SPA.05.012, "Quantification of Containment Leakage-Only Release Categories for PINGP ILRT Extension Risk Assessment".

APPENDIX A

Effect of Age-Related Degradation on Risk Impact Assessment for Extending Containment Type A Test Interval

A.1.0 PURPOSE

The purpose of this calculation is to assess the effect of age-related degradation of the containment on the risk impact for extending the Prairie Island Integrated Leak Rate Test (ILRT or Containment Type A test) interval from ten to fifteen years.

A.2.0 INTENDED USE OF ANALYSIS RESULTS

The results of this calculation will be used to indicate the sensitivity of the risk associated with the extension in the ILRT interval to potential age-related degradation of the containment shell to support obtaining NRC approval to extend the Integrated Leak Rate Test (ILRT) interval at Prairie Island from 10 years to 15 years. This calculation actually evaluates the impact of extending the interval from 3 years to 15 years.

A.3.0 TECHNICAL APPROACH

The present analysis shows the sensitivity of the results of the assessment of the risk impact of extending the Type A test interval for the Prairie Island to age-related liner corrosion.

The prior assessment included the increase in containment leakage for EPRI Containment Failure Class 3 leakage pathways that are not included in the Type B or Type C tests. These classes (3a and 3b) include the potential for leakage due to flaws in the containment shell. The impact of increasing the ILRT Interval for these classes included the probability that a flaw would occur and be detected by the Type A test that was based on historical data. Since the historical data includes all known failure events, the resulting risk impact inherently includes that due to age-related degradation.

The present analysis is intended to provide additional assurance that age-related liner corrosion will not change the conclusions of the prior assessment. The methodology used for this analysis is similar to the assessments performed for Calvert Cliffs Nuclear Power Plant (CCNPP - Reference A1), Comanche Peak Steam Electric Station (CPSES - Reference A2), D. C. Cook (CNP - Reference A3) and St. Lucie (SL - Reference A4) in responses to requests for additional information from the NRC staff. The CCNPP, CPSES and CNP extension request submittals have been approved by the NRC.

The significantly lower potential for corrosion of freestanding steel shell containments, such as that at Prairie Island, is considered. This is due to the significantly smaller surface area susceptible to corrosion resulting from foreign material imbedded in concrete contacting the steel containment. Because of this, the analysis is carried out separately for those portions of the containment not in potential contact with foreign material and those portions in potential contact with the foreign material. (This is considered more appropriate than the cylinder and dome portions and the basement portions utilized in prior analyses.)

As in Reference A1, this calculation uses the following steps with Prairie Island values utilized where appropriate:

Step1 - Determine corrosion-related flaw likelihood.

Historical data will be used to determine the annual rate of corrosion flaws for the containment. The significantly lower potential for corrosion in the freestanding Prairie Island containment will be included.

Step 2 - Determine age-adjusted flaw likelihood.

The historical flaw likelihood will be assumed to double every 5 years. The cumulative likelihood of a flaw is then determined as a function of ILRT interval.

Step 3 - Determine the change in flaw likelihood for an increase in inspection interval.

The increase in the likelihood of a flaw due to age-related corrosion over the increase in time interval between tests is then determined from the results of Step 2.

Step 4 - Determine the likelihood of a breach in containment given a flaw.

For there to be a significant leak from the containment, the flaw must lead to a gross breach of the containment. The likelihood of this occurring is determined as a function of pressure and evaluated at the Prairie Island ILRT pressure.

Step 5 - Determine the likelihood of failure to detect a flaw by visual inspection.

The likelihood that the visual inspection will fail to detect a flaw will be determined considering the portion of the containment that is uninspectable at Prairie Island as well as an inspection failure probability.

Step 6 – Determine the likelihood of non-detected containment leakage due to the increase in test interval.

The likelihood that the increase in test interval will lead to a containment leak not detected by visual examination is then determined as the product of the increase in flaw likelihood due to the increased test interval (Step 3), the likelihood of a breach in containment (Step 4) and the visual inspection non-detection likelihood (Step 5). The results of the above for the two regions of the containment are then added to get the total increased likelihood of non-detected containment leakage due to age-related corrosion resulting from the increase in ILRT interval.

The result of Step 6 is then used, along with the results of the prior risk analysis in the body of this analysis to determine the increase in LERF as well as the increase in person-rem/year and conditional containment failure probability due to age-related liner corrosion.

A.4.0 INPUT INFORMATION

1. General methodology and generic results from the Calvert Cliffs assessment of age-related liner degradation (Reference A1).

2. The Prairie Island ILRT test pressure of 46.0 psig (Reference A5).

3. Prairie Island containment failure pressure of 137 psia based on Kewaunee ILRT Extension Submittal. (Reference A12).

4. The surface area of the containment potentially in contact with foreign material either imbedded in the adjacent concrete or trapped in the areas of limited

access is 12,106 ft^2. This is based on calculations of the total inside surface area of the containment both accessible and inaccessible for inspection from ASME Section XI, Subsection IWE records [A7], and application of a factor to represent the assumed surface area in contact with concrete [A12] .

5. The number of containments, either free-standing steel shell or concrete with steel liners is 104 and the average area of steel potentially in contact with foreign material either imbedded in the adjacent concrete or trapped in the areas of limited access is 61,900 ft^2 (Reference A11).

A.5.0 REFERENCES

A1. "Calvert Cliffs Nuclear Power Plant Unit No. 1; Docket No. 50-317, Response to Request for Additional Information Concerning the License Amendment Request for a One-Time Integrated Leakage Rate Test Extension, "Constellation Nuclear letter to USNRC, March 27, 2002.

A2. "Comanche Peak Steam Electric Station (CPSES), Docket Nos. 50-445 and 50-446, Respond to Request for Additional Information Regarding License Amendment Request (LAR) 01-14 Revision to Technical Specification (TS) 5.5.16 Containment Leakage Rate Testing Program," TXU Energy letter to USNRC, June 12, 2002.

A3. "Donald C. Cook Nuclear Plants Units 1 and 2, Response to Nuclear Regulatory Commission Request for Additional Information Regarding the License Amendment Request for a One-time Extension of Integrated Leakage Rate Test Interval," Indiana Michigan Power Company, November 11. 2002.

A4. "St. Lucie Units 1 and 2, Docket Nos. 50-335 and 50-389, Proposed License

Amendments, Request for Additional Information Response on Risk-Informed One Time Increases in Integrated Leak Rate Test Surveillance Interval," Florida Power & Light Company letter to USNRC, December 13, 2003.

A5. Prairie Island Surveillance SP-1071.5 (SP-2071.5), "Integrated Leakage Rate Test Final Preparation and Test procedure", Rev. 15.

A6. FAI/92-47, "A Phenomenological Evaluation Summary on Containment Overpressurization in Support of the Prairie Island Individual Plant Examination," V.SMR.94.010, April, 1992.

A7. Prairie Island engineering calculation ENG-ME-542, "Accessible Surface Area Calculation for ASME Section XI subsection IWE".

A8. "Containment Liner Through Wall Defect due to Corrosion," Licensing Event Report, Ler-NA2-99-02, North Anna Nuclear Power Plant Station Unit 2.

A9. "Brunswick Steam Electric Plant, Units 1 and 2, Dockets 50-325 and 50-324/License Nos. DPR=71 and DPR-62, Response tp Request for Additional Information Regarding Request for License Amendments – Frequency of Performance Based Leakage Rate Testing," CP&L letter to USNRC, February 5, 2002.

A10. "IE Information Notice No. 86-99; Degradation of Steel Containments." USNRC, December 8. 1986.

A11. E. R. Schmidt, "Calculation of Industry Average Containment Surface Area Subject to Age-Related Corrosion Due to Foreign Material," Analysis File 17547-0001-A4, Rev. 0, November 14, 2003.

A12. "Kewaunee Nuclear Power Plant, Docket 50-305, License No. DPR-43, License Amendment Request 198 to the Kewaunee Nuclear Power Plant Technical Specifications for One-Time Extension of Containment Integrated Leak Rate Test Interval", June 20, 2003.

A.6.0 MAJOR ASSUMPTIONS

1. As indicated in the NRC's (References A3 and A4, for example) there have been 4 instances of age-related corrosion leading to holes in steel containment liners or shells. Three of these instances (Cook - Reference A3, North Anna – Reference A8 and Brunswick – Reference A9) were in concrete containments with steel liners and due to foreign material imbedded in the concrete in contact with the steel liner. The fourth instance (Oyster Creek – Reference A10) was in a freestanding steel containment and occurred in an area where sand fills the gap between the steel shell and the surrounding concrete and was attributed to water accumulating in this sand. This data is therefore considered to represent a corrosion induced failure rate only for the area of the Prairie Island containment steel shell in contact with concrete or other areas where foreign material may be trapped. For the other areas where the containment steel shell is not likely to be in contact with foreign material, the corrosion induced failure rate should be substantially lower and taken to be that based on no observations of corrosion induced failure of the containment steel shell in these regions.

2. The historical data of age-related corrosion leading to holes in the steel-containment has occurred primarily (3 out of 4 instances) for steel lined concrete containments. For these containments the surface area in contact with the concrete comprises essentially the entire surface area of the containment. For Prairie Island, the surface area calculation is taken from calculations of the total inside surface area of the

containment both accessible and inaccessible for inspection from ASME Section XI, Subsection IWE records [A7]. From these records, the surface area inside the containment that is accessible for inspection is 60,215 square feet, and the surface area that is not accessible for inspection is 315 square feet. Since the greater the surface area in contact with the concrete, the greater the chance of foreign material being in contact with steel containment and therefore the greater the chance of corrosion induced flaws, the containment failure rate due to corrosion will be taken to be proportional to the surface area in contact with the concrete. The total surface area in contact with the concrete is calculated by multiplying the total (accessible and inaccessible) inside containment surface area by a factor of 20% [A12]. This results in a calculated total surface area in contact with the concrete of (60,215 + 315)*0.2 = 12,106 square feet. The containment failure rate due to corrosion will be taken to be that for the industry times the ratio of the surface area at risk for Prairie Island to the average area at risk for the industry.

3. The visual inspection data is conservatively limited to 5.5 years reflecting the time from September 1996, when 10 CFR 50.55a started requiring visual inspection, through March 2002, the cutoff date for this analysis. Additional success data were not used to limit the aging impact of this corrosion issue, even though inspections were being performed prior to September 1996 (and after March 2002). While some liner corrosion has been evident in these inspections, when it is identified it is corrected (when possible) and the area is placed under an augmented inspection program to monitor for further degradation. There has been no evidence that any of the corrosion issues identified have led to holes in the containment liner. (Step 1).

4. As in Reference A1, the containment flaw likelihood is assumed to double every 5 years. This is included to address the increased likelihood of corrosion due to aging. (Step 2)

5. The likelihood of a significant breach in the containment due to a corrosion induced localized flaw is a function of containment pressure. At low pressures, a breach is very unlikely. Near the nominal failure point, a breach is expected. As in Reference A1, anchor points of 0.1% chance of cracking near the flaw at 20 psia and 100% chance at the failure pressure 137 psia. The failure pressure of 137 psia was based on the value used for the Kewaunee ILRT Extension Submittal [A12]. This value was used because the design of Prairie Island containment is identical to the design of Kewaunee containment. Another evaluation [A6] of the Prairie Island containment indicates that the failure pressure could be as high as 165 psia. Consequently, the use of the Kewaunee containment failure pressure is conservative.

6. In general, the likelihood of a breach in the lower head region of the containment occurring, and this breach leading to a large release to the atmosphere, is less than that for the cylindrical portion of the containment. The assumption discussed in item 5 above is, however, conservatively applied to the lower head region of the containment, as well as to the cylindrical portions.

7. All non-detected containment overpressure leakage events are assumed to be large early releases.

8. The interval between ILRTs at the original frequency of 3 tests in 10 years is taken to be 3 years.

A.7.0 IDENTIFICATION OF COMPUTER CODES:

None used.

A.8.0 DETAILED ANALYSIS:

A.8.1 Step 1 – Determine a corrosion-related flaw likelihood.

As discussed in Assumptions 1, 2 and 3, the likelihood of through wall defects due to corrosion for the areas of the containment potentially contacted by foreign materials is based on 4 data points in 5.5 years.

[4 failures*(12,106 ft^2 / 61,900ft^2)/ (104 plants*5.5 years/plant) = 1.37E-03 per year]

For the areas of the containment where foreign material is not likely to contact the containment the defect likelihood is taken to be that for no observed failures using a non-informative prior distribution.

Failure Frequency = [# of failures (0) + ½] / (Number of unit years (104*5.5))]
= 8.74E-04 per year.

A similar area-at-risk correction as above for the area in contact with concrete is not appropriate for the area where foreign material is not likely to contact the containment since the majority of the steel liner or shell for all plants has at least one side of the surface subject to this reduced corrosion (and none has been observed).

A.8.2 Step 2 – Determine age-adjusted liner flaw likelihood.

Reference A1 provides the impact of the assumption that the historical flaw likelihood will double every 5 years on the yearly, cumulative and average likelihood that an age-related flaw will occur. For a flaw likelihood of 5.2E-03 per year, the 15 year average flaw likelihood is 6.27E-03 per year for the cylinder/dome region. This result of Reference A1 is generic in nature, as it does not depend on any plant specific inputs, except the assumed historical flaw likelihood.

For the present assumption of 4 historical failures in 104 plants, the 15 year average flaw likelihood is 26.3% (1.37E-03/5.2E-03 = 0.263 or 26.3%) of the above value (6.27E-03) or 1.65E-03 per year, and in accordance with Assumption 1, is applicable to the region of the containment potentially in contact with foreign material.

Similarly, for the region of the containment not potentially in contact with foreign material, the 15 year average flaw likelihood is 16.8%(8.74E-04/5.2E-03 = 0.168) of the above value (6.27E-03) or 1.05E-03 per year.

A.8.3 Step 3 – Determine the change in flaw likelihood for an increase in inspection interval.

The increase in the likelihood of a flaw due to age-related corrosion over the increase in time interval between tests from 3 to 15 years is determined from the result of Step 2 in Reference A1 to be 8.7% for the cylinder/dome region based on assumed historical flaw likelihood and the resulting 6.27E-03 per year 15 year average flaw likelihood. This result of Reference A1 is generic in nature, as it does not depend on any plant specific inputs, except the assumed historical flaw likelihood.

For the present assumption of 4 historical failures in 104 plants, the increase in the likelihood of a flaw due to age-related corrosion over the increase in time interval between tests from 3 to 15 years is 26.3% (as in Step 2) of that given in Reference A1 (0.263*8.7%) or 2.29% and in accordance with Assumption 1 is applicable to only the region of the containment potentially in contact with foreign material.

Similarly, for the region of the containment not potentially in contact with foreign material, the increase in the likelihood of a flaw due to age-related corrosion over the increase in time interval between tests from 3 to 15 years is 16.8% (as in Step 2) of that given in Reference A1 or 1.46%.

A.8.4 Step 4 - Determine the likelihood of a breach in containment given a liner flaw. The likelihood of a breach in containment occurring is determined as a function of pressure as follows:

For a logarithmic interpolation on likelihood of breach

LOG (likelihood of breach) = m (pressure) + a

Where m = slope
a = intercept

The values of m and a are determined from solution of the two equations for the values of 0.1% at 20 psia and 100% of containment failure pressure of 137 psia (Reference A12).

$$\text{Log } 0.1 = m*20 + a$$

$$\text{Log } 100 = m*137+a$$

or

$$m = (\text{Log } 100 - \text{Log } 0.1)/(137-20) = 0.026$$

and

$a = \text{Log } 0.1 - 0.026*20 = -1.51$

The upper end of the range of Prairie Island ILRT pressure of 46.0 psig (Reference A5) gives the highest likelihood of breach.

At 60.7 psia (46.0 + 14.7), the above equation gives

$$\text{Log (likelihood of breach)} = 0.026*60.7 - 1.51 = 0.0435$$

$$\text{Likelihood of breach} = 10^{0.0435} = 1.11\%$$

In accordance with Reference A1, the above value is for the cylinder/dome portions of the containment. For this analysis, this value is also assumed to be applicable to the region of the containment potentially in contact with foreign material.

A.8.5 Step 5 - Determine the likelihood of failure to detect a flaw by visual inspection

A review of the geometry of the containment shell and the relative areas that are not inspectable and those in potential contact with foreign material, indicates that these two areas are essentially the same, both comprising approximately 20% of the total surface area of the steel shell (Reference A12). Consequently, the portion of the containment not likely to be in contact with potential foreign material is 100% visually inspectable, while the portion that may be in contact with potential foreign material is not visually inspectable. A 10% failure rate for that portion of the containment that is visually inspectable is assumed.

A.8.6 Step 6 – Determine the likelihood of non-detected containment leakage due to the increase in test interval.

The likelihood of non-detected containment leakage in each region due to age-related corrosion of the liner considering the increase in ILRT interval is then given by:

The increased likelihood of an undetected flaw because of the increased ILRT interval (Step3)	*	The likelihood of a containment breach given a liner flaw (Step 4)	*	The likelihood that visual inspection will not detect the flaw (Step 5)

= 1.46% * 0.0111*0.10 = 0.0016% for the regions not potentially contacted by foreign material.

= 2.29% * 0.0111*1.0 = 0.025% for the regions potentially contacted by foreign material.

The total is then the sum of the values for the two regions or

Total Likelihood of Non-Detected Containment Leakage = 0.0016% + 0.025% = 0.0269% for the ILRT interval increase from 3 years to 15 years.

Exhibit E

Summary of the Prairie Island Nuclear Generating Plant Probabilistic Risk Assessment Revisions

1. Background

The Prairie Island Nuclear Generating Plant (PINGP) Individual Plant Examination (IPE) was submitted to the NRC by letter dated March 1, 1994 to respond to Generic Letter 88-20, "Individual Plant Examination for Severe Accident Vulnerabilities – 10CFR 50.54(f)." The NRC sent requests for Additional Information (RAI) to Northern States Power Company on December 21, 1995. The NRC accepted the IPE by letter dated May 16, 1997. The NRC letters noted that the IPE submittals met the intent of Generic Letter 88-20, "Individual Plant Examination for Severe Accident Vulnerabilities – 10CFR 50.54(f)", dated November 23, 1988.

The history of the PRA model development from the IPE to the current Revision 2.1 model including model enhancements and dominant accident classes is described below.

2. IPE Results (Level 1 and Level 2, Revision 0)

The first full-scope PRA analysis done for PINGP was that performed to satisfy the IPE requirements, and was completed in February 1994. This was a study to determine vulnerabilities to severe accidents from at-power operation. It was based on a Level 1 and Level 2 PRA model performed for Unit 1. Unit 2 vulnerabilities were qualitatively evaluated based on the Unit 1 results and consideration of asymmetries in plant design and operation that exist between the units. The study found no vulnerabilities to severe accidents at the PINGP. Previously, a limited-scope Individual Plant Evaluation Methodology (IPEM) analysis was completed in 1992. The IPE PRA analysis started with the models built for the IPEM study, and additional details, including the Level 2 portions, were added to arrive at the full scope analysis. The initial data collection effort for that analysis was performed for the period 1978 – 1987, except for the initiating event frequency analysis, which used plant trip information over the period 1975 – 1987. This PRA study is now considered to be Revision 0 of the Level 1 and 2 PRA models.

The core damage frequency (CDF) calculated for the IPE was 5.0E-5/rx-yr. The dominant accident sequences by initiating event were:

- Loss of coolant accident (LOCAs) (24%);
- Loss of off-site power (LOOP) including SBO (22%);
- Internal Flooding (21%);
- Transients excluding LOOP (19%); and
- Steam generator tube rupture (SGTR) (13%).

Large early release frequency (LERF) was not quantified for the IPE. The total release frequency (the frequency of core damage followed by containment failure) was calculated to be 2.0E-5/rx-yr, giving a conditional containment failure probability (CCFP) of approximately 40% (69% including induced SGTR, which was addressed by an Emergency Operating Procedure (EOP) change almost as soon as the IPE was submitted). The dominant contributors to the CCFP were:

- Late containment failure due to overpressure following early core damage and vessel failure at high pressure (55%); and
- SGTR (35%).

3. IPE- External Events (IPEEE) Submittals

The initial PINGP IPEEE analysis was submitted to the NRC in December 1996. It included a seismic margins analysis, a Level 1 fire PRA based upon the IPE Revision 0 Level 1 PRA model, and additional plant-specific analyses to address the "other" postulated external initiating events required for the IPEEE. The fire portion of the IPEEE was updated in 1998. The fire PRA for this update used the Level 1, Revision 1.0 model (see below). The NRC issued a Staff Evaluation Report (May 29, 2001) concluding that "the aspects of seismic; fires; and HFO (other external events) were adequately addressed".

4. Level 1, Revision 1.0

Revision 1.0 of the Unit 1, Level 1 PRA model was completed in 1996. In addition to adding modeling for a few more balance-of-plant systems (for example, the non-safeguards station air system and the steam dump and circulating water systems), this update included modeling for a number of significant changes to the plant safeguards electrical systems that were not yet installed at the time of the IPE submittal. Examples include elimination of sub-fed 480V motor control centers (MCCs), division of the two Unit 1 safeguards 480 V AC buses into four buses and relocation of those buses within the plant; and significant reliability upgrades for the DC power system. Component failure and unavailability data for six key systems were updated for the period 1986 through 1995, as were the initiating event frequencies. LOCA frequencies were reanalyzed to make them more plant-specific, using a pipe failure study technique developed by the Electric Power Research Institute (EPRI).

The CDF calculated for the Revision 1.0 PRA model was 2.4E-5/rx-yr. The dominant accident sequences by initiating event were:

- LOCAs (5%);
- LOOP including station blackout (SBO) (34%);
- Internal Flooding (36%);
- Transients excluding LOOP (9%); and
- SGTR (14%).

The decline in the CDF compared with the Revision 1.0 (IPE) model results was primarily due to the development of plant-specific LOCA initiating event frequencies, credit given for the station air to instrument air cross-tie capability, and credit given for an electrical system upgrade and equipment relocation on Unit 1 that effectively eliminated the 480 V safeguards bus dependency on room ventilation.

5. Level 1, Revision 1.1

Revision 1.1 of the Unit 1, Level 1 model was completed in 1999. This was essentially the same model as Revision 1.0; however, a single top fault tree approach to the quantification of overall CDF was used, as was a standard truncation level of 1E-10. Previously, the PRA models were quantified using Set Equation Transformation System (SETS), which allowed different truncation levels for each individual core damage sequence. The total CDF for the Revision 1.1 model was calculated to be 2.35E-5/rx-yr, and the breakdown of the CDF by initiating event was approximately that shown above for the Revision 1.0 model.

6. Level 1, Revision 1.2

Revision 1.2 of the Unit 1, Level 1 model was completed in 2001. Significant changes were incorporated during this revision. Many of these changes were based on comments received by the Westinghouse Owners Group (WOG) PRA Certification Team Review that took place in October 2000. Changes include:

- New LOCA break size groupings (small LOCA (SLOCA), medium LOCA (MLOCA), large LOCA (LLOCA));
- New LOCA break size frequencies based on generic data from NUREG/CR-5750;
- Update to several initiating event frequencies (LOOP, loss of DC (LODC));
- Inclusion of Offsite Power recovery actions for non-SBO events;
- Creation of initiating event trees for the cooling water system (CL), component cooling system (CC), and Instrument Air systems;
- Power operated relief valve (PORV) LOCA events have been added;
- Changes to SBO success criteria (removal of diesel generator recovery);
- Random reactor coolant pump (RCP) Seal Failure initiating event was added;
- Updates to several system fault trees;
- Credit for the Pressurizer PORV accumulator;
- Upgrade to the Human Reliability Analysis (key operator actions); and
- The mission time for the emergency diesel generators (EDG) and CL pumps were changed from 6 hours to 24 hours since offsite power recovery is credited.

The component failure rates from the 1995 update were reviewed against generic data. If significant differences were found and there was a large impact on the CDF, the component failure rate was updated. Only a few changes were made. Specifically, EDG D5 and D6 failure and unavailability data was changed based on the limited amount of operating experience available during the update period. Generic failure rates from NUREG/CR-4550 were used for the D5 and D6 EDGs.

The CDF calculated for the Revision 1.2 PRA model was 2.200E-5/rx-yr. The dominant accident sequences by initiating event were:

- LOOP including SBO (23.9%);
- LOCAs (23.8%);
- Internal Flooding (22.5%);
- SGTR (14.8%); and
- Transients excluding LOOP (15.0%).

There was not a significant change in the overall CDF value compared with the Revision 1.1 model. However, the distribution of the accident sequences has changed significantly. The LOOP contribution decreased due to crediting offsite power recovery for the non-SBO sequences. The SGTR contribution increased due to re-analysis of the human error actions associated with this event. The LOCA contribution increased due to redefining the LOCA break sizes and the use of generic LOCA frequencies. The internal flooding contribution decreased due to crediting the Pressurizer PORV accumulator. The transient contribution increased due to several reasons since it encompasses many initiating events.

- The loss of feedwater transient increased due to changes in the human reliability analysis (HRA). (Key operator actions were re-analyzed based on conditional events, which resulted in a higher probability of failure. A key operator action in the loss of feedwater water transient affected by this includes: establishing feed and bleed conditional on restoring feedwater.);
- The normal transient contribution increased due to the modeling addition of challenging a pressurizer PORV during the transient and resulting in a PORV LOCA; and
- The contribution from a loss of CC and CL transients increased due to the addition of initiating event tree modeling for CL and CC systems.

7. Unit 1 and Unit 2 Level 1, Revision 2.0

Level 1, Revision 2.0 PRA model update was performed in order to obtain a working PRA model for Unit 2. Previously, all probabilistic risk analysis for Unit 2 have involved application of the Unit 1 model results, with modifications that attempted to consider the impact of asymmetries between the units. The update was also performed to correct some errors and make some enhancements to the existing Revision 1.2 PRA model. The model update was completed in 2002 and was built upon the Level 1 Revision 1.2 model. Major model changes included with this update are:

- Addition of Unit 2 frontline and support system logic modeling;
- Addition of Unit 2 accident sequence logic modeling;
- Inclusion of CDF and LERF calculations for Unit 2;

- Removal of the boric acid storage tank (BAST) input to the safety injection (SI) pumps suction logic. The primary suction supply is now only the refueling water storage tank (RWST);
- Enhancement of the existing quantification methodology, including incorporation of fault tree-based deletion of mutually exclusive events, including multiple initiating events;
- Modification to the charging pump system fault tree logic to include an operator action to restart the pumps after a LOOP event since they are not included in the sequencer logic;
- Use of the same common cause failure (CCF) event for the residual heat removal (RHR) pump discharge check valves in the injection, recirculation, and shutdown cooling modes;
- A new operator action to prevent load sequencer failure due to loss of cooling to the 4KV safeguards bus rooms (Bus 15, Bus 16, Bus 25, and Bus 26 rooms) were incorporated into the model. In conjunction with this change, a factor for the sequencer failure at elevated temperatures was added to the fault tree logic for the safeguards bus;
- Update to the logic modeling for the supply /exhaust fans 21, 22, 23, 24 which supply air to the Unit 2 safeguards bus rooms. The original modeling assumed that none of the fans were running (but one train is normally running). This modeling changed assumed supply/exhaust fan sets 21 and 22 are normally running and supply/exhaust 23 and 24 are in standby. Therefore, the failure to start logic was only included for sets 23 and 24. The CCF to start basic events for all four sets was removed from the model; and
- An incorrect and non-conservative mutually exclusive event related to the Screenhouse Flood Zone 2 Initiating event (I-SH2FLD) was removed from the logic. This will result in an increase in the contribution of the Screenhouse Flood Zone 2 (SH2FLD) event to the overall results.

The CDF calculated for the Unit 1 Revision 2.0 PRA model was 2.19E-5/rx-yr. The dominant accident sequences by initiating event were:

- LOOP including SBO (26.0%);
- LOCAs (22.4%);
- Internal Flooding (23.2%);
- SGTR (13.2%); and
- Transients excluding LOOP (15.2%).

There was not a significant change in the overall CDF value compared with the Revision 1.2 model. There were some changes in the distribution of the accident sequences. The LOOP contribution increased due to the additional cutsets (with higher probabilities) related to the LOOP event with a failure of the operator to start a charging pump and a loss of the CL pumps which lead to a RCP seal LOCA. The small LOCA contribution decreased (which results in a decrease in the LOCA contribution) due to a decrease in the removal of the BAST as a supply source to the SI pumps. The SGTR contribution decreased due the new mutually exclusive logic incorporated into the model, specifically related to preventative maintenance on EDGs. The flood contribution increased due to the removal of a mutually exclusive event related to the Screenhouse Flood Zone 2 initiating event.

The CDF calculated for the Unit 2 Revision 2.0 PRA model was 2.52E-5/rx-yr. The dominant accident sequences by initiating event were:

- LOOP including SBO (25.6%);
- LOCAs (19.4%);
- Internal Flooding (20.1%);
- SGTR (11.8%); and
- Transients excluding LOOP (23.1%).

There is not a previous Unit 2 model to which the results can be compared; however, Unit 2 can be compared to the Unit 1 results. Unit 2 CDF value is higher than the Unit 1 result. The Unit 2 CDF value is higher due to an increase in the LOOP and Loss of DC Power Train A initiating events. The LOOP initiating event increase is due to the Unit 2 asymmetries associated with the auxiliary feedwater (AFW) system (Unit 2 motor driven AFW (MDAFW) pump powered from Train A verses Unit 1 MDAFW pump powered from Train B) and the emergency diesel generators system (D5 and D6 have higher CCF to start probability verses D1 and D2). These asymmetries result in LOOP event cutsets that have higher probabilities than the Unit 1 results. Also, since the Unit 2 MDAFW pump is powered from Train A, the Loss of DC power Train A event has a larger impact on the Unit 2 CDF results (contributes almost 9% to the overall CDF). This initiator causes the transient portion of the Unit 2 CDF to increase to 23.1% verses 15.2% in the Unit 1 results. The internal flooding event probability remains virtually the same between the Unit 2 and Unit 1 results; however, due to the increase in Unit 2 CDF value, the contribution in the Unit 2 result is lower. This is also the case for the SGTR event.

8. Unit 1 and Unit 2 Level 1, Revision 2.1

Revision 2.1 of the Unit 1 and Unit 2, Level 1 model was completed in early 2005. Significant changes were incorporated during this revision. Changes include:

- Update to LOOP initiating event frequency including the addition of consequential LOOP;
- Updates to the RHR, SI, AFW, CL, CC, 125 VDC system, EDG and instrument power system fault trees;
- Upgrade to the HRA for key operator actions and inclusion of misalignment and miscalibration events;
- Updated failure data for the EDG and AFW systems;
- Updated common cause values for the EDG and AFW systems; and
- Updated internal flooding analysis.

The CDF calculated for the Unit 1 Revision 2.1 PRA model was 1.47E-5/rx-yr. The dominant accident sequences by initiating event were:

- LOCAs (53.5%);
- Transients excluding LOOP (20.9%);
- SGTR (14.2%);
- LOOP, including SBO (9.9%); and
- Internal flooding (1.7%).

There was not a significant change in the overall CDF value compared with the Revision 2.0 model. However, the distribution of the accident sequences has changed significantly. The LOOP contribution decreased due to recalculation of the LOOP initiating event frequency and new EDG common cause and failure data. The LOCA contribution increased due to re-analysis of the human error actions associated with these events. The internal flooding contribution decreased due to reanalysis of the pipe break frequencies and the flows from the break. The transient contribution changed due to several reasons since it encompasses many initiating events.

- Transients increased due to the addition of AFW recirculation line valve failure logic, which was added in the recent fault tree update. This added an extra failure mode for the AFW system;
- The normal transient contribution decreased due to the modeling addition of a factor for the percentage of time that a pressurizer PORV might lift following a transient initiating event; and
- The credit for the pressurizer PORV air accumulator was increased which reduced the contribution of the loss of instrument air initiating event.

The CDF calculated for the Unit 2 Revision 2.1 PRA model was 1.63E-5/rx-yr. The dominant accident sequences by initiating event were:

- LOCAs (48.5%);
- Transients excluding LOOP (27.3%);
- SGTR (12.8%);
- LOOP, including SBO (10.1%); and
- Internal flooding (1.5%).

There was a significant change in the overall CDF value compared with the Revision 2.0 model. The distribution of the accident sequences has also changed significantly. The LOOP contribution decreased due to recalculation of the LOOP initiating event frequency and new EDG common cause and failure data. The SGTR contribution decreased due to re-analysis of the human error actions associated with this event. The LOCA contribution increased due to re-analysis of the human error actions associated with these events. The internal flooding contribution decreased due to reanalysis of the pipe break frequencies and the flows from the break. The transient contribution changed due to several reasons since it encompasses many initiating events.

- Transients increased due to the addition of AFW recirculation line valve failure logic, which was added in the recent fault tree update. This added an extra failure mode for the AFW system;
- The normal transient contribution decreased due to the modeling addition of a factor for the percentage of time that a pressurizer PORV might lift following a transient initiating event; and
- The credit for the pressurizer PORV air accumulator was increased which reduced the contribution of the loss of instrument air and loss of A train DC initiating events.

Level 2, Revision 1.0

Revision 1.0 of the Unit 1, Level 2 PRA model was completed in 1999, and was built upon the Level 1 Revision 1.0 model. In addition to the changes incorporated in the revision to the Level 1 model, this update reflected credit for the potential for hot leg creep rupture phenomenon to facilitate vessel failure at low pressure for early core damage sequences and credit for a change to the emergency procedures that greatly reduced the risk from induced steam generator (SG) tube creep rupture events (these events were not modeled in the 1.0 analysis). Also, credit for containment spray (CS) recirculation was removed from the model, since procedural guidance for operator initiation of the system in the EOPs was removed (based on a licensing-basis calculation that showed that containment pressure would be below the threshold requiring CS recirculation operation for any analyzed event after the RWST had reached low-low level).

The total release frequency (the frequency of core damage followed by containment failure) was calculated to be 8.8E-6/rx-yr, giving a conditional containment failure probability (CCFP) of approximately 38%.

The decline in the total release frequency was primarily due to the decline in the Level 1 CDF (from the Revision 0 to the Revision 1 analysis). The decline was slightly less than that seen in the CDF itself due to the relatively large CDF contribution to both measures from internal flooding events. The contribution of flooding events to the total release frequency remained relatively constant at about 35% (9E-6).

LERF was quantified for the Revision 1 Level 2 model. Early core damage sequences involving containment bypass (SGTR and intersystem LOCA (ISLOCA) sequences) and containment isolation failure were considered to be those with the potential to produce a large early release. The calculated LERF was 3.8E-7/rx-yr. The dominant contributors to the LERF are:

- ISLOCA (58% of LERF),
  - Catastrophic rupture or transfer open of two series RHR Hot Leg Suction motor operated valves (MOVs) followed by operator failure to cool down and depressurize the reactor to limit RHR pump seal leakage. (41% of LERF),

- Catastrophic rupture or transfer open of two series RHR Hot Leg Suction MOVs, or rupture of two series SI injection check valves, or one SI injection check valve and the RHR shutdown cooling isolation MOV, followed by rupture of the low pressure RHR piping outside containment. (17%);

- SGTR (15%),
  - STGR followed by common cause failure of either the SI pumps (to start or run) or the RWST to SI suction MOVs to open, followed by operator failure to cool down and depressurize the RCS to RHR shutdown cooling conditions. (14%); and

- Transient or LOCA core damage sequences followed by early containment failure (typically through hydrogen combustion) (25%),
  - AFW Pump/Instrument Air Compressor room internal flood (15%),
  - RCP seal LOCA involving loss of CL and Train A 4kV AC power (5%),
  - Loss of secondary heat sink with failure of operator action to perform bleed and feed operation (3%), and
  - Medium or large LOCA with failure of Emergency Core Cooling System (ECCS) recirculation (1%).

Level 2, Revision 1.1

No Level 2 or LERF model was developed with this designation (no update to the Level 2 models or to LERF was performed which used the Level 1, Revision 1.1 model as input). The basis for this was the nearly identical nature of the Revision 1.0 and Revision 1.1 Level 1 models, that is, no significant difference in the Level 2 results could exist based solely on the move to the Revision 1.1 model.

Level 2, Revision 1.2

A full Level 2 revision to correspond with the Level 1, Revision 1.2 model is not yet available. However, an update to the LERF results based on the Level 1, Revision 1.2 model has been performed.

One change made to the Level 1 model incorporated in Revision 1.2 had a significant impact on the LERF results. The human error probability (HEP) for the failure of the operator to cool down and depressurize the RCS to shutdown cooling following a SGTR, originally a screening value with a very low probability, was increased by an order of magnitude. This change shifted the majority of the LERF contribution to SGTR sequences (from ISLOCA sequences).

Other than the changes to the underlying Level 1 model, the following changes were made to the LERF calculation itself:

1) Failure of containment isolation was modeled using a fault tree model for each unscreened containment penetration from the previous analysis. The previous LERF analysis used a point value estimate for the failure of containment isolation.
2) Core damage sequences involving early containment failure but without containment bypass (from the full Level 2 analysis) were excluded from the LERF result. As stated previously, a full Level 2 model update based on the Level 1 Revision 1.2 model has not yet been performed. In addition, these sequences had been conservatively added to the LERF calculation in the absence of certainty about whether they met an industry standard definition of large, early release that was still in development. The American Society of Mechanical Engineers (ASME) PRA Standard defines a large early release as "the rapid, unmitigated release of airborne fission products from the containment to the environment occurring before the effective implementation of offsite emergency response and protective actions". Under this definition, it is not clear that these early containment failure sequences actually would lead to large early releases, since containment is not directly bypassed. The IPE source term analysis showed only the containment bypass events (induced-SGTR, ISLOCA) to result in the highest releases of volatile (non-noble gas) radionuclides. SGTR events also involved large releases of volatiles, but was considered to be a late release. Containment isolation failure sequences involved early releases but the magnitude of the volatiles was categorized as medium. Also, the majority of these sequences were assumed to lead to early containment failure due to very conservative treatment of the hydrogen combustion phenomenon. However, position papers created for the IPE conclude that, even assuming worst-case hydrogen production conditions post core damage, pressures developed within the containment following a detonation of the hydrogen would not approach the ultimate failure pressure of the containment shell itself. Evidence also exists that ignition sources energetic enough for detonation of the hydrogen do not exist within the containment. Even if containment failure were to occur by this mechanism, it is likely that the timing of the failure would be later than that specified in the LERF definition (time for implementation of protective action recommendations from the emergency plan response would be available due to the additional time required to pressurize containment to its ultimate failure pressure). Therefore, the non-bypass early containment failure sequences were excluded from the LERF calculation (SGTR and containment isolation failure sequences were left in).

The calculated LERF for Revision 1.2 was 6.9E-7/rx-yr. The dominant contributors to the LERF are:

- SGTR (87% of LERF),
  - STGR followed by common cause failure of either the SI pumps (to start or run) or the RWST to SI suction MOVs to open, followed by operator failure to cool down and depressurize the RCS to RHR shutdown cooling conditions. (69% of LERF);

- ISLOCA (13%),

- Catastrophic rupture or transfer open of two series RHR Hot Leg Suction MOVs, or rupture of two series SI injection check valves, or one SI injection check valve and the RHR shutdown cooling isolation MOV, followed by rupture of the low pressure RHR piping outside containment. (9%),
- Catastrophic rupture or transfer open of two series RHR Hot Leg Suction MOVs followed by operator failure to cool down and depressurize the reactor to limit RHR pump seal leakage. (4%); and

- Core damage sequences followed by failure of containment isolation (0.2%),
  - AFW/Instrument Air Compressor room internal flooding, RCS PORV air accumulators insufficient for bleed and feed operations, two series air operated valves (AOVs) fail to close due to CCF (Containment penetrations 11, 20, or 26) (0.07%), and
  - SLOCA, master relays SIA-A1 and SIA-B1 fail to energize (0.02%).

Level 2, Revision 2.0

A full Level 2 revision to correspond with the Level 1, Revision 2.0 model is not yet available. However, an update to the LERF results based on the Level 1, Revision 2.0 model has been performed.

One change made to the Level 1 model incorporated in Revision 2.0 had a significant impact on the LERF results. The removal of the BAST as a supply source to the SI pump suction logic significantly reduced to contribution of the SGTR event to the LERF result.

Other than the changes to the underlying Level 1 model, the following changes were made to the LERF calculation itself:

- The containment isolation failure logic modeling (gate 1CIF and 2CIF) was expanded to include catastrophic leakage from the equipment hatch door, the fuel transfer tube, and open personnel or maintenance airlock doors.

The calculated LERF for the Unit 1 Revision 2.0 was 3.88E-7/rx-yr. The dominant contributors to the LERF are:

- SGTR (76% of LERF),
  - STGR followed by common cause failure of the SI pumps (to start or run), followed by operator failure to cool down and depressurize the RCS to RHR shutdown cooling conditions. (28% of LERF);

- ISLOCA (23% of LERF),
  - Catastrophic rupture or transfer open of two series RHR Hot Leg Suction MOVs, rupture of two series SI injection check valves, or one SI injection check valve and the RHR shutdown cooling isolation MOV, followed by rupture of the low pressure RHR piping outside containment. (11% of LERF),

- Catastrophic rupture or transfer open of two series RHR Hot Leg Suction MOVs followed by operator failure to cool down and depressurize the reactor to limit RHR pump seal leakage. (7% of LERF); and

- Core damage sequences followed by failure of containment isolation (1% of LERF),
  - AFW/Instrument Air Compressor room internal flooding, RCS PORV air accumulators insufficient for bleed and feed operations, two series AOVs fail to close due to CCF (Containment penetrations 11, 20, or 26) (0.3% of LERF), and
  - SLOCA, master relays SIA-A1 and SIA-B1 fail to energize (0.08% of LERF).

The calculated LERF for Unit 2 Revision 2.0 was 3.90E-7/rx-yr. The dominant contributors to the LERF are:

- SGTR (76% of LERF),
  - STGR followed by common cause failure of the SI pumps (to start or run), followed by operator failure to cool down and depressurize the RCS to RHR shutdown cooling conditions. (28% of LERF);

- ISLOCA (23% of LERF),
  - Catastrophic rupture or transfer open of two series RHR Hot Leg Suction MOVs, or rupture of two series SI injection check valves, or one SI injection check valve and the RHR shutdown cooling isolation MOV, followed by rupture of the low pressure RHR piping outside containment. (11% of LERF),
  - Catastrophic rupture or transfer open of two series RHR Hot Leg Suction MOVs followed by operator failure to cool down and depressurize the reactor to limit RHR pump seal leakage. (7% of LERF); and

- Core damage sequences followed by failure of containment isolation (1% of LERF),
  - AFW/Instrument Air Compressor room internal flooding, RCS PORV air accumulators insufficient for bleed and feed operations, two series AOVs fail to close due to CCF (Containment penetrations 11, 20, or 26) (0.3% of LERF).

Level 2, Revision 2.1

A full Level 2 revision to correspond with the Level 1, Revision 2.1 model is not yet available. However, an update to the LERF results based on the Level 1, Revision 2.1 model has been performed. Other than the changes to the underlying Level 1 model, there were no changes made to the LERF model.

The calculated LERF for the Unit 1 Revision 2.1 was 5.74E-7/rx-yr. The dominant contributors to the LERF are:

- SGTR (54.4% of LERF),
  - STGR followed by common cause failure of the SI pumps (to start or run), followed by operator failure to cool down and depressurize the RCS to RHR shutdown cooling conditions; and

- ISLOCA (45.2% of LERF),
  - Catastrophic rupture or transfer open of two series RHR Hot Leg Suction MOVs followed by operator failure to cool down and depressurize the reactor to limit RHR pump seal leakage, and
  - Catastrophic rupture or transfer open of two series RHR Hot Leg Suction MOVs, or rupture of two series SI injection check valves, or one SI injection check valve and the RHR shutdown cooling isolation MOV, followed by rupture of the low pressure RHR piping outside containment.

The resulting LERF is higher than the Revision 2.0 model because the recent HRA updates for the Revision 2.1 model resulted in a higher failure probability for the operator actions to cooldown and depressurize the RCS. This resulted in a higher contribution from the ISLOCA sequences and consequentially, a higher LERF value.

The calculated LERF for the Unit 2 Revision 2.1 was 5.74E-7/rx-yr. The dominant contributors to the LERF are:

- SGTR (54.4% of LERF),
  - STGR followed by common cause failure of the SI pumps (to start or run), followed by operator failure to cool down and depressurize the RCS to RHR shutdown cooling conditions; and

- ISLOCA (45.1% of LERF),
  - Catastrophic rupture or transfer open of two series RHR Hot Leg Suction MOVs followed by operator failure to cool down and depressurize the reactor to limit RHR pump seal leakage, and
  - Catastrophic rupture or transfer open of two series RHR Hot Leg Suction MOVs, or rupture of two series SI injection check valves, or one SI injection check valve and the RHR shutdown cooling isolation MOV, followed by rupture of the low pressure RHR piping outside containment.

The resulting LERF is higher than the Revision 2.0 model because the recent HRA updates for the Revision 2.1 model resulted in a higher failure probability for the operator actions to cooldown and depressurize the RCS. This resulted in a higher contribution from the ISLOCA sequences and consequentially, a higher LERF value.

Exhibit F

Peer Review Certification of the Prairie Island Nuclear Generating Plant Probabilistic Risk Assessment

The Peer Review Certification of the Prairie Island Nuclear Generating Plant (PINGP) probabilistic risk assessment (PRA) performed by the Westinghouse Owners Group (WOG) during the period of September 25 – 29, 2000 resulted in five Findings and Observations (F&O) with a significance level of "A" and 32 F&O with the significance level of "B". The significance levels of the WOG Peer Review Certification process have the following definitions:

A - Extremely important and necessary to address to ensure the technical adequacy of the PRA, the quality of the PRA, or the quality of the PRA process.

B - Important and necessary to address, but may be deferred until the next PRA update.

The F&O with the significance levels of "A" and "B" were reviewed, dispositioned and documented before the EDG Completion Time Extension License Amendment Request (LAR) was submitted. The following table provides a summary of the significance levels A and B F&O and the corresponding resolutions. The designators of the F&O are as follows:

- IE - Initiating Event
- AS - Accident Sequence Analysis
- TH - Thermal Hydraulic Analysis
- SY - System Analysis
- DA - Data Analysis
- HR - Human Reliability Analysis
- DE - Dependency Analysis
- QU - Quantification
- MU - Maintenance and Update

Item	F&O	Observation	Significance	Status & Resolution	Impact on EDG Completion Time
1	IE-1, sub-element 4	Several items were identified relative to initiating event identification and grouping. (1) The basis for excluding from the model challenges to the PORVs post reactor trip is not adequately explained. This affects the initiating event grouping for Events 2, 8, 10, 16, 18, 19. Additionally, the model does not appear to directly consider the consequences of a stuck open PORV (no actual transfer to the Small LOCA ET). Though the plant has not actually experienced a PORV opening following a transient, this does not provide a sufficient basis for concluding that PORVs will not open for all initiators in this class. Appendix D writeup (D.12) shows that the PORV-related event frequency contribution is small (4.17E-5) and encompassed by the contributions from other Small LOCAs. However, the new (Rev 2) LOCA frequency for S2 is 6E-5, so Stuck Open PORVs are no longer small contributors to this class. (2) Random RCP seal failure (i.e., a random failure resulting in RCP seal leakage greater than normal makeup capability) was not included in the IE frequency for small LOCA. Such potential random RCP seal failures	B	CLOSED – A transfer was added to the small LOCA event tree from a stuck open PORV following a normal transient. A Random RCP seal LOCA frequency was obtained from NUREG/CR-5750, "Rates of Initiating Events at U.S. Power Plants: 1987 – 1995 and added as a transfer to the small LOCA event tree. The third issue with the T2 initiator comes from the proposed model and documentation (by a contractor). We are not using that information in the updated model. All initiators used in the original model (I-TR1, I-TR2, I-TR3 and I-TR4) are inputs into the transient event tree.	The PRA model was changed as a result of this F&O and any impact on the results are already reported in the LAR.

Item	F&O	Observation	Significance	Status & Resolution	Impact on EDG Completion Time
		have been assessed at frequency in range 1E-3 to 5E-3 by various sources. This event has been neglected in the IE selection. The updated PI PRA frequency for S1 due to other than random RCP seal LOCA is 5E-3. This is comparable to frequency of random RCP seal LOCA, so the event should be considered. (3) The T2 initiator (without a stuck open PORV) does not appear to be an input into the transient event tree sequences.			
2	IE-4, sub-element 13	The dual-unit LOSP initiator frequency calculation in file V.SMD.96.005 (Recalculation of LOSP Initiator) appears to be in error. The calculation divides LOSP into PLC (plant centered), Weather (WRL) and Grid Loss (GRL) events, which is correct. Prairie Island has had 2 dual unit LOSP events in it's 21year history (as of 1996 when file was made). In calculating the exposure time, the calc assumes 42 plant years for PI, because it counts unit 1 and unit 2 separately (to be consistent with the generic LOSP data). The resulting Bayesian updated dual-unit LOSP frequency is 0.0316. But if the units are counted individually, then it must be considered that a dual unit LOSP	A	CLOSED - The LOOP initiator frequency was updated using a plant specific Bayesian update with current industry and NRC data through 2003.	The PRA model was changed as a result of this F&O and any impact on the results are already reported in the LAR.

Item	F&O	Observation	Significance	Status & Resolution	Impact on EDG Completion Time
		at unit 2 affects unit 1, as opposed to the way it was calculated, which effectively assumes unit 1 and unit 2 are two different sites. Therefore, the WRL and GRL frequencies must be doubled because a dual unit LOSP at unit 2 affects unit 1. Alternatively, the PI site could be considered as a single unit and there would be 2 failures in 20 site-years. This would be in conflict the generic data and would require modification of the generic exposure time.			
3	IE-6, sub-element 16	Bayesian update was used for LOSP frequency. The Bayesian update algorithm used is very sensitive to the error factor chosen for the generic data. The mean value for the generic prior distribution for LOSP was 0.0181 with an EF of 1.4. The plant specific data shows that 2 LOSP events have occurred in 25.7 site years (corresponding to a plant-specific point estimate of 0.0788/yr). However, the updated mean calculated using the Bayesian code and these values is .0187 - which hardly moves the prior mean at all. If the EF on the prior were changed to 5, then the updated mean would be .044/yr, apparently more reflective of the plant experience. The reviewers believe that several calculational mistakes were made in	B	No action was taken on this F&O, as the calculation is not used in any of the current models and will never be used.	No impact.

Item	F&O	Observation	Significance	Status & Resolution	Impact on EDG Completion Time
		this analysis. 1) the EF of the prior is calculated assuming that a chi-squared distribution represents the generic data, based on 43 events. This produces a very low EF, since this process ignores the site to site variability. 2) the Bayesian update algorithm used is sensitive to the choice of EF. 3) if the EF on the prior actually was 1.4, then uncertainty bounds of prior and plant specific data would not overlap and it could be said that the prior is not from the same data base as the plant specific. The latest LOSP report from INEL (NUREG/CR-5496) provides a generic mean across the country of .05/yr. The PRA should be able to defend the derivation of a value significantly less than this.			
4	IE-8, sub-element 13	This comment was generated by a review of the failure database being developed for PRA Rev 2. The reviewers identified several concerns with the data reduction for LOSP. The LOSP frequency as calculated by this work is 0.0181. The LOSP as calculated by INEL in NUREG/CR-5496 is 0.05. This discrepancy is large considering the importance of the event to the overall	B	CLOSED - No action was taken on this F&O, as the calculation is not used in any of the current models and will never be used.	No Impact.

Item	F&O	Observation	Significance	Status & Resolution	Impact on EDG Completion Time
		PRA results. In addition: 1) More than 75% of the events in the EPRI database (EPRI-TR-106306) have been screened out as not being applicable. The reviewers checked the screening assessments for several events. In several cases the screening criteria seemed optimistic and used the clause that "power could have been restored if necessary", or "if this event happened at power, OSP *[offsite power]* would have been restored". Other times it was stated that an error occurred at shutdown that could not occur at power. The screening of events appears to have been too optimistic about events at shutdown that were assumed to not be possible at power. 2) The data base screens out all but 56 events. However, the LOSP frequency is calculated as 43 events/2347 yrs. There is no explanation of the difference between 56 events and 43 events. 3) The basis for the exposure time of 2347 reactor-years is unclear. In the RIF component database the accumulated operating time is listed as 2546 licensed years, 2472 critical years and 2402 commerical years. If there have been 2402 commercial years of operation, at an average availability factor of 80%, there should			

Item	F&O	Observation	Significance	Status & Resolution	Impact on EDG Completion Time
		be 1920 full power years of operation, not 2347. The "2347 reactor years" used for the LOSP calculation obviously includes the time spent at shutdown. If all refueling LOSP events are removed from the failure list, then the time spent at shutdown should also be removed from the exposure time.			
5	AS-6, sub-element 4	The reviewers did not find a discussion of dual unit initiators and subsequent station response, although at least one such initiator (dual-unit loss of offsite power) is identified and an associated frequency is included among the initiating events. After the review, Prairie Island PRA personnel clarified that three potential dual-unit initiating events were identified: Loss of Offsite Power, Loss of Instrument Air, and Loss of Cooling Water. Of these, only loss of offsite power is modeled as a dual-unit event affecting unit 1 (i.e., an event for which the status of the opposite unit is considered in the accident sequences with respect to availability of opposite unit equipment). The others are not so treated, because their baseline CDF contribution (when considered as single-unit events) is relatively small.	B	CLOSED - At the time of the review, a dual unit model did not exist. A dual unit model was created that includes dual unit initiator fault tree modeling for loss of instrument air, loss of cooling water and LOOP.	The PRA model was changed as a result of this F&O and any impact on the results are already reported in the LAR.
6	AS-8, sub-	Given the dependence of primary and secondary pressure relief on	B	A detailed initiating event fault tree was created for loss of	The PRA model was changed as a result of this F&O and any

Item	F&O	Observation	Significance	Status & Resolution	Impact on EDG Completion Time
	element 10	instrument air, the loss of instrument air event should be discussed, and possibly modeled, independently of other transient events. The primary PORVs or possibly the primary/secondary safety valves may lift to provide pressure relief in this scenario (loss of IA). This may be a unique enough plant response to warrant special treatment. In addition, challenging these valves results in an increase in the S2 LOCA or steam line break initiating event frequency.		instrument air.	impact on the results are already reported in the LAR.
7	AS-11, sub-element 8	The General Transient event tree (Figure 4.2 in the Accident Sequence notebook) shows that if a consequential PORV LOCA occurs, a transfer is made to the S1 LOCA event tree. The S1 LOCA size range has been defined as 3/8" to ~ 1" (actually 7/8"). However, the equivalent flow area for a primary PORV is expected to be larger than this, and should probably be considered in the S2 LOCA category. Additionally, the transfer for the MSLB scenario is not included in the Rev. 1.1 model.	B	CLOSED - The PRA model was changed such that standard industry LOCA sizes were used. (3/8 – 2' for small LOCA, 2 – 6 " for medium LOCA and >6" for large LOCAs). The PORV LOCA transfer goes to the correct LOCA tree and the MSLB PORV LOCA transfer was also added.	The PRA model was changed as a result of this F&O and any impact on the results are already reported in the LAR.

Item	F&O	Observation	Significance	Status & Resolution	Impact on EDG Completion Time
8	AS-12, sub-element 8	Consequential steam generator tube rupture (i.e., SGTR resulting from a transient that causes a large pressure differential across the steam generator tubes, such as steamline rupture or inadvertently opened and stuck secondary side relief or safety valve) is not modeled in the accident sequences. The possibility of this consequential event should be addressed in the PRA.	B	CLOSED - The steam generators at Prairie Island are designed such that the tubes can withstand full system dp across the tubes from the primary or secondary sides without sustaining any consequential tube ruptures. Because of this, the consequential tube rupture event following a primary or secondary depressurization was not modeled.	No Impact. This F&O has been resolved and incorporated into the Prairie Island PRA model used to perform the extended EDG Completion Time analysis.
9	AS-14, sub-element 17	The success criteria for AF are incomplete for Steam Line Break Events. Specifically, they do not include the requirement to isolate flow to the faulted SG.	B	CLOSED – The steam generator that has a steam line break upstream of the MSIV OR has a MSIV that fails to close on a steam line break downstream of the MSIV will be failed. The model was changed so that AF is isolated to a faulted SG.	The PRA model was changed as a result of this F&O and any impact on the results are already reported in the LAR.
10	AS-15, sub-element	These observations relate to the Revision 2. Event Tree Notebook	C (items 1-5) B (items 6-12)	CLOSED – No action was taken on this F&O, as this documentation is	This is a documentation enhancement issue and has no impact on the PRA model

Item	F&O	Observation	Significance	Status & Resolution	Impact on EDG Completion Time
	3	provided in the peer review package. Documentation detail is limited in some areas, and should be expanded. Actually, some of these details already exist in the previous layer of notebooks; it would be useful to capture this information in one ET notebook to assure completeness and consistency is obtained and maintained for the future updates. Specific observations noted are as follows (some references are specifically to the SGTR event tree discussion, but may also be applicable to other initiating events): 1. Event progress is not described in detail (ESDs do not have much more information content than ETs; they do not make up for the lack of detailed description of the event, nodes, operator actions, EOPs involved, etc.). 2. Top event descriptions are not detailed (SG isolation appears to be consisting of MSIV closure only. What about operator actions, termination of AFW flow in to the faulted SG etc). 3. Top events with operator actions are not clearly delineated and the dependence among top events is not indicated. 4. References to EOPs are not		not used in any of the current models and will never be used. The event tree notebooks have been recently improved to strengthen the documentation.	used for the LAR.

Item	F&O	Observation	Significance	Status & Resolution	Impact on EDG Completion Time
		complete (in which EOP(s) and by what means does the operator identify and isolate a faulted SG?) 5. There should be a one-to-one correspondence between the items listed in section 4.10 and Appendix D. A summary table may do it. 6. Why is there no SGTR-W branching when SGTR-STI fails in the SGTR event tree (there is one in the ESD) ? 7. Give guidance on what happens to sequences that branch into other ETs and end successfully there: for example SGTR has a transfer into ATWS and is successful; is it a success, or simply truncated because it is low frequency? What is the criteria for terminating event tree to event tree looping? 8. MS-FLB events need to be discussed; they have an additional event tree node of "failure to isolate faulted SG", which makes the event tree different from the transient ET. SBO event tree needs to be discussed. 9. Where are the "qualitatively assessed" items in ESDs? 10. What is the process that transfers			

Item	F&O	Observation	Significance	Status & Resolution	Impact on EDG Completion Time
		the system success criteria and operator action definition/success/dependence information from Section 4 and Appendix D to the system analysts and HRA analysts? A couple of summary tables may be used to organize the "work orders" generated for the system and HRA analysts. 11. What about stuck open pressurizer PORV after a LOSP event? (maybe after a loss of MFW event also?!) Generic T&H analyses show that the PORVs are challenged after a LOSP event. 12. What happens to the events with RCS break flows that are less than makeup capacity; how long does the CVCS have to run; what happens if CVCS fails; What is the underlying assumption in not modeling them with an event tree (small frequency?) ?			
11	AS-18, sub-element 10	Two steam generator tube rupture modeling items were noted: The dependency between having a faulted SG following a SGTR with overfill and a stuck open relief valve and the top gates for depressurization and AF are not considered in the SGTR development. The AF top logic	A	CLOSED - The initiating event for SGTR has been added under the respective SG gate and SG PORV gate. Therefore, the fault tree logic was modified as to fail the ability to feed and depressurize the ruptured SG.	The PRA model was changed as a result of this F&O and any impact on the results are already reported in the LAR.

Item	F&O	Observation	Significance	Status & Resolution	Impact on EDG Completion Time
		credits feed to both SGs. Though acceptable for most cases, if there is a stuck open relief valve on the ruptured generators, operators are directed to isolate that generator (including AF). This reduces the ability to depressurize with the 1 SG and AF to the faulted generator being isolated. In SGTR, the AFW success criteria require AFW to 1 of 2 SG. Feeding of the ruptured SG is allowed (as directed by the EOP's). The success path at function AFW therefore allows feeding of the bad SG. Subsequent event tree headings ask for isolation of the ruptured generator. The fault tree development only asks about closing of the MSIV on the ruptured generator. In reality, if the good generator could not be fed, the ruptured generator could not be isolated. If the bad generator is being fed, the sequence needs to transfer on the failure path at "isolation" and go into ECA3.1/3.2. The fault tree logic for "isolation" needs to include logic that "failure" to isolate the ruptured generator can be caused by failure of the good generator to be fed. If the ruptured generator is being fed, it will not be isolated.			
12	TH-1, sub-	Two items were noted regarding derivation of success criteria for	A	CLOSED - SI Accumulators were added	The PRA model was changed as a result of this F&O and any

Item	F&O	Observation	Significance	Status & Resolution	Impact on EDG Completion Time
	element 7	accumulators using MAAP 3b calculations. A MAAP calculation was used to determine that accumulators are only necessary for design-basis LOCAs. The MAAP PWR Application Guidelines specifically state that MAAP is not an appropriate code for use in analyzing rapid-depressurization events such as larger LOCAs. No basis was found for not including accumulators in Small LOCA event trees in cases when high pressure injection fails. A MAAP calculation without accumulators was available, but this case showed core damage.		to the large LOCA event tree success criteria. The SLOCA and MLOCA event trees were changed to require accumulator injection with the RHR pump injection (1/1 accumulator and 1/2 RHR pump). One accumulator is failed due to a break in the RCS cold leg.	impact on the results are already reported in the LAR.
13	TH-4, sub-element 4	The timing for switchover to recirculation in an analysis proposed for PRA Rev. 2 seems very conservative. First, it is assumed that containment spray initiates even for small LOCAs, thereby reducing the time to drain the RWST. Second, a calculation assuming low pressure injection is used for the timing of both high- and low-pressure recirculation. If high pressure recirculation is needed, RCS pressure must be above the shutoff head of the RHR pumps so that no low pressure injection flow has occurred, greatly increasing the time before recirculation is required. This could be important because the lineup	B	CLOSED - No action was taken on this F&O, as the calculation is not used in any of the current models and will never be used.	No Impact.

Item	F&O	Observation	Significance	Status & Resolution	Impact on EDG Completion Time
		for high pressure recirculation is the only local critical step in the recirculation procedure. This local step is the reason that timing is so critical.			
14	TH-9, sub-element 4	The LOCA break size definitions for the PINGP PRA are based on different criteria than those for most other PRAs. This would be acceptable if the underlying analyses provided sufficient basis for the definitions, but it appeared that the available analyses do not adequately support the selected definitions. The following is a comparison of the definitions and their bases, with focus on the injection phase, as discerned from the Event Tree Success Criteria notebook: PINGP PRA S1 (Small LOCA category 1) = breaks that are too large to be accommodated by the normal charging system and too small to provide adequate decay heat removal through the break; range defined as 3/8" to ~ 1" diameter breaks. PINGP PRA S2 (Small LOCA category 2) = breaks that do not depressurize to within the low head injection system capability but are within the capability of the high head injection system, and that are	B	CLOSED - The PRA model was changed such that standard industry LOCA sizes were used. (3/8 – 2' for small LOCA, 2 – 6 " for medium LOCA and >6" for large LOCAs). SI Accumulators were added to the large LOCA event tree success criteria.	The PRA model was changed as a result of this F&O and any impact on the results are already reported in the LAR.

Item	F&O	Observation	Significance	Status & Resolution	Impact on EDG Completion Time
		sufficiently large to provide decay heat removal via the break; range defined as ~ 1" to 5" diameter breaks. TYPICAL PRA Small LOCA = breaks that are too large to be accommodated by the normal charging system and too small to depressurize to the high head injection setpoint sufficiently rapidly to avoid the need for decay heat removal; typically 3/8" to 2" diameter breaks. PINGP Medium LOCA = breaks that are sufficiently large to depressurize to the shutoff head of the RHR pumps but small enough to be within the capability of the high head injection system, with decay heat removal via the break; range defined as 5" to 12" diameter breaks. TYPICAL Medium LOCA = breaks that are sufficiently large to depressurize to the high head injection setpoint but for which pressure remains above the RHR pump shutoff head, with decay heat removal via the break; typically 2" to 6" diameter breaks. PINGP Large LOCA = breaks beyond the capability of the high head injection system but which do not require accumulator injection, with decay heat removal via the break and			

Item	F&O	Observation	Significance	Status & Resolution	Impact on EDG Completion Time
		shutdown reactivity insertion via borated injection; range defined as 12" and greater but less than the design basis LOCA break size. PINGP DBA Large LOCA = break size for which accumulator injection is required in addition to low head injection; range defined as the design basis break size. TYPICAL Large LOCA = breaks that are sufficiently large to depressurize to the RHR pump shutoff head, with decay heat removal via the break and shutdown reactivity insertion via borated injection; typically > 6" diameter breaks. Among the implications of the above are the following: The PINGP PRA S1 SLOCA plant response and modeling should be similar to the SLOCA response and modeling for typical plant PRAs. The PINGP PRA S2 SLOCA plant response and modeling should be similar to the MLOCA response and modeling for typical plant PRAs. The PINGP PRA MLOCA assumes that a single train of high head injection can mitigate what is equivalent to the low end of the large LOCA size range for typical plants, for which high head injection is normally			

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		not credited. The PINGP PRA LLOCA (non-DBA) plant response and modeling differs from the LLOCA response and modeling for typical plant PRAs in that it does not include a requirement for accumulator injection; the LLOCA DBA plant response and modeling is equivalent to that for typical PRAs.			
15	TH-13, sub-element 1	The Success Criteria notebook provides some perspective on the rationale for what was done. However, the guidance reviewed does not explicitly state the approach to be used for determining the need for and types of thermal/hydraulic calculations necessary to support the PRA success criteria. Several instances have been noted (in other F&Os) for which detailed analyses have been required, and the MAAP code was used without sufficient justification or check for applicability.	B	CLOSED - The Success Criteria notebook is in the process of update in order to incorporate this documentation.	This is a documentation enhancement issue and has no impact on the PRA model used for the LAR.
16	TH-16, sub-element 8	As described in the Safeguards Ventilation System Notebook, room cooling requirements have been addressed for the equipment modeled in the PRA. This notebook presents a discussion, with references to engineering calcs, regarding the need for cooling for each such room. However, in some cases, it is not	B	CLOSED - The Safeguards Ventilation system notebook has been updated in order to incorporate this documentation.	This is a documentation enhancement issue and has no impact on the PRA model used for the LAR.

Item	F&O	Observation	Significance	Status & Resolution	Impact on EDG Completion Time
		clear that the rationale provided for not modeling room cooling is sufficient. For example, for the Relay Room, it is stated that analyses have shown that it is necessary to maintain the temperature below 120 deg F, but that room heatup analysis showed that the temperature would reach 120 deg F at 11 hours. Then the statement is made that "This provides sufficient time for the operator to perform the corrective actions per C37.9 AOP2." While there may indeed be sufficient time to perform corrective actions, there is no guarantee that the actions will be performed. Since the temperature exceeds the allowable equipment temperature well within the PRA mission time, there is a dependency on room cooling for this room that should either be modeled or more carefully analyzed.			
17	TH-17, sub-element 4	The fault tree model, for large, medium, and some small S2 LOCAs, credits ECCS flow to the faulted loop. Unless thermal-hydraulic analyses exist to provide a basis for this, it would be expected that the injection path associated with the faulted loop is unavailable, and only the remaining path would be available for success. The success criterion should be 1 of 2 pumps to the single intact RCS loop.	B	CLOSED – The PRA model was changed to ensure that ECCS flow and SI accumulators are failed to the RCS loop that is experiencing the LOCA.	The PRA model was changed as a result of this F&O and any impact on the results are already reported in the LAR.

Item	F&O	Observation	Significance	Status & Resolution	Impact on EDG Completion Time
18	SY-2, sub-element 5	The corrective maintenance unavailability basic event for the 120VAC IP Inverters is modeled incorrectly in the Fault Tree. As modeled, with an inverter out of service, the fault tree still allows power to be supplied from the alternate AC source through the inverter to the instrument panel. The same comment may also apply to other inverter (and output breaker) failure models in the PRA.	B	CLOSED - The AC instrument power fault tree was changed such that the corrective maintenance event was moved higher in the fault tree so that it fails all power supplies that feed the instrument bus through the inverter.	The PRA model was changed as a result of this F&O and any impact on the results are already reported in the LAR.
19	SY-4, sub-element 7	The 120 VAC Model does not include failures of the 120 VAC Panel (bus faults). These are normally modeled in most PRAs.	B	CLOSED – Instrument panel bus faults were added to the model.	The PRA model was changed as a result of this F&O and any impact on the results are already reported in the LAR.
20	SY-7, sub-element 10	As described in the Safeguards Ventilation System Notebook, room cooling requirements have been addressed for the equipment modeled in the PRA. This notebook presents a discussion, with references to engineering calcs, regarding the need for cooling for each such room. However, in some cases, it is not clear that the rationale provided for not modeling room cooling is sufficient. For example, for the Relay Room, it is stated that analyses have shown that it is necessary to maintain the	B	CLOSED - The Safeguards Ventilation system notebook has been updated in order to incorporate this documentation.	This is a documentation enhancement issue and has no impact on the PRA model used for the LAR.

Item	F&O	Observation	Significance	Status & Resolution	Impact on EDG Completion Time
		temperature below 120 deg F, but that room heatup analysis showed that the temperature would reach 120 deg F at 11 hours. Then the statement is made that "This provides sufficient time for the operator to perform the corrective actions per C37.9 AOP2." While there may indeed be sufficient time to perform corrective actions, there is no guarantee that the actions will be performed. Since the temperature exceeds the allowable equipment temperature well within the PRA mission time, there is a dependency on room cooling for this room that should either be modeled or more carefully analyzed. As another example, for the rooms housing 120VAC Instrument Power equipment, there is no discussion of ventilation requirements in the notebook. The equipment survivability discussion notes that room cooling is required, and that 4 hours are available following loss of ventilation to re-establish ventilation. However, actions to open doors or re-establish cooling are not modeled in the fault tree. One editorial problem also pertains to the ventilation modeling. Assumption 5 in the SI system notebook states that room cooling is not required for SI in injection mode, but the assumption			

Item	F&O	Observation	Significance	Status & Resolution	Impact on EDG Completion Time
		does not address recirculation mode. The room heatup calculation actually assumed sump recirculation mode, and that should be noted in the notebook.			
21	SY-17, sub-element 13	The PORV Fault Tree for Feed & Bleed is applied in sequences involving initiators that would cause containment isolation on an S signal. The fault tree takes no credit for the PORV accumulators to allow the PORVs to be used after isolation of the air supply, and also takes no credit for operator action to re-establish air to the containment. As a result, the model assumes failure of both PORVs when air is isolated to containment. As a result of the assumption that the PORV accumulators are not sufficient for Feed and Bleed in scenarios involving an S signal, the model appears to be overly pessimistic regarding credit for feed & bleed. FR.H.1 Step 11 provides direction to the operators to re-establish air to containment, so consideration should be given to modeling this action, along with associated valve failure probabilities.	B	CLOSED - The pressurizer PORV air accumulator has been added to the feed and bleed model. The failure probability assigned is high (0.9), as the accumulator is not specifically designed for feed and bleed use.	The PRA model was changed as a result of this F&O and any impact on the results are already reported in the LAR.
22	DA-3, sub-element	The operating hours for the D5 and D6 diesels were not calculated	B	CLOSED - The operating hours for D5 and D6 were corrected. The	The PRA model was changed as a result of this F&O and any impact on the results are

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	7	correctly. In file V.SMD.95.007, the exposure time for the planned maintenance (PM) and corrective maintenance (CM) unvailablilites is stated as 175,344 hours. This is the same exposure time as for D1/D2, and appears to be the full 11 years of operation in the database. D5 and D6 were not installed until 1993. The exposure time the CM and PM for D5 and D6 should be about 24,000 hr. This increases the PM and CM unavailabilities by a factor of 4. (The exposure time for fail to start and fail to run is calculated correctly.)		plant specific data for all EDG has recently been updated to reflect operating history from 1994 – 2004.	already reported in the LAR.
23	DA-5, sub-element 8	The common cause failure modeling was based on methods and data in NUREG/CR-4780. Although the methods in this document are still valid, the CCF factors (numerical values) are based on plant experience and judgment prior to 1988. NUREG/CR-6268 (INEL) is a more current source of common cause data and should be used in the next update. There are several beta factors in the current model that are 0.1 to 0.4 in value. (RHR, Containment Sprays, Fan coolers). In light of the more recent data in NUREG/CR-6268, these beta values are high and should be revised.	B	OPEN – The majority of the common cause factors are still calculated using methods from NUREG/CR-4780. Recently, the CCF factors for the EDG and AFW systems were recalculated using the guidance from NUREG/CR-6268. It is planned to use this new guidance to update all CCF factors by the end of 2005.	The PRA model was changed as a result of this F&O and any impact on the results are already reported in the LAR.

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24	DA-6, sub-element 2	Plant specific data used to support PRA Rev. 1 was collected for the IPE in 1988. Generic failure rates were used extensively in the IPE. In 1995, an updated data collection was performed for AFW pumps, DG's, Air compressors, Cooling water pumps, SI pumps, and RHR pumps, which were selected on the basis of risk-significance to the PRA results. A larger data development effort is underway for Rev 2, but this still limits the plant specific data period to 1995. The observed status of the use of plant-specific data, given the above, is the following: (a) 6 components in the Rev. 1 PRA have failure rates based on plant-specific data through 1995; (b) a limited number of other components in Rev. 1 have failure rates based on plant-specific data through 1988; (c) most of the failure rates in Rev. 1 are generic; (d) after the Rev. 2 update, data will only be current through 1995. The reviewers believe the PRA relies too heavily on plant data that is not sufficiently current with the as-operated plant.	B	OPEN – The data updated in 1995 was for the systems that are the main drivers of risk. Plant specific data will be updated as needed for risk significant systems. The AFW and EDG system data was recently updated to include plant specific data from 1994 – 2004. The remaining systems will be updated by the end of 2005.	The PRA model was changed as a result of this F&O and any impact on the results are already reported in the LAR.
25	DA-8, sub-	Notebook V.SMN.92.028 states that	B	CLOSED - The NRC issued this same	No Impact.

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	element 10	4kv breakers are included in the fault tree models but are not common caused together because the the components supplied by the breakers already include any breaker common cause failures that have occurred. The component boundaries for all components fed by these breakers (pumps, buses) should be consistent so that breaker failure rates and CCF rates can be consistently applied. There are also no CCF events for bus feeder breakers. Most PRAs treat 4kv breakers separately from served components, and include separate CCF events for the important sets of breakers.		question during the initial review of the IPE. A specific Request For Information question was issued by the NRC related to the omission of the CCF modeling of circuit breakers and electrical switchgear. The PI PRA group response follows: "Common cause failures of circuit breakers and switchgear were not explicitly modeled, but common cause failures of loads supplied through the breakers, such as pumps, valves and other components that can be attributable to common cause mechanisms were modeled. This implicitly captures circuit breaker common cause failures that are associated with these components. As with circuit breakers, common switchgear (in terms of function and the effects of failures) are implicitly analyzed with other failures, such as emergency diesel generator common cause failures." The NRC approved the IPE, including this modeling	

Item	F&O	Observation	Significance	Status & Resolution	Impact on EDG Completion Time
				assumption.	
26	DA-10, Sub-element 17	In Rev 1, when the plant specific data was 0 failures in T exposure time, the failure rate was calculated by assuming 0.5 failures in T exposure time. This is mathematically equivalent to using a Bayesian update with a Jeffrey's prior. There is no way of knowing if this estimate is reasonable or not. A more technically sound approach is to use a generic prior for Bayesian update. In Rev2, the data development has changed to use 0.3 failures in the exposure time. There is no basis for this practice, expecially when the Rev 2 data makes significant use of Bayesian process.	B	CLOSED - No action was taken on this F&O, as the calculation is not used in any of the current models and will never be used.	No impact.
27	DA-11, sub-element 4	The number of plant specific failures for CVCS pumps in Rev 2.0 seems high - about 60-80. There is no reason to use Bayesian update techniques when there are such a large number of plant specific failures. In fact, since the plant specific failure rate is relatively high compared to generic sources, it could likely be shown that the PI CVCS pumps are not in the same population as generic pumps and a Bayesian update process should not be used.	B	CLOSED - No action was taken on this F&O, as the calculation is not used in any of the current models and will never be used.	No Impact.
28	HR-4, sub-element	The equation used to quantify latent errors is not intuitive, and appears to be incorrect.	B	CLOSED – A recent update of the pre-initiator human error model	The PRA model was changed as a result of this F&O and any impact on the results are

Item	F&O	Observation	Significance	Status & Resolution	Impact on EDG Completion Time
	6	The equation presented in the HRA notebook suggests that there is a time period in which a component can be considered available after corrective maintenance (CM) but prior to retest (assumed to be 4 hours). Conversely, the equation implies that no retest is performed following preventive maintenance (PM). This most likely does not reflect maintenance practices. Furthermore, the peer review guidance suggests that latent errors may be screened when a post maintenance test is performed. The summation of the PM, test (T), and random failure (RF) frequencies does not have any physical meaning, as the terms appear to be mutually exclusive. In addition, for components only exposed to latent error on a refueling outage frequency, the approach mentions that the operators would most likely find a latent error prior to startup. For these cases, a TI value of 4 is assumed which is very similar to the CM cases. However, in practice, at-power surveillance test intervals are being substituted for TI values applied to components exposed to latent error only during refuelling (e.g., CTRAINAXXZ, CVHCS11XXZ). Lastly, it seems that the refueling frequency value of 8.55E-05/hr is artificially reducing the		has been completed such that industry accepted methods are now used.	already reported in the LAR.

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		HEP in these cases. Subsequent to the review, PINGP PRA personnel provided the response shown under "Plant Response or Resolution.			
29	HR-6, sub-element 10	The HRA documentation indicates that operator interviews were conducted when determining the execution time of procedure steps, but the values used appear to be generic. Further, a "generic" value of 45 minutes is identified as the shortest time to core damage for any accident. This value is then used in the screening analysis for several operator actions where the time to core damage is being estimated. There doesn't appear to be a basis for the 45 minute value. Furthermore, it not clear that this value is applicable to the actions modeled.	B	CLOSED - A recent update of the pre-initiator human error model has been completed such that industry accepted methods are now used.	The PRA model was changed as a result of this F&O and any impact on the results are already reported in the LAR.
30	HR-7, sub-element 13	Two of the ten most important operator actions, ABUS27RESY and N121DRYXXY (sorted by FV), are quantified using screening values. This is contrary to the PINGP PRA groundrules and industry guidance.	A	CLOSED - ABUS27RESY was removed from the model, as this is an action that would not be performed during accident conditions. A recent plant modification was added to the instrument air system fault tree which caused the importance of operator action N121DRYXXY to decrease. An HRA upgrade was performed for the EDG	The PRA model was changed as a result of this F&O and any impact on the results are already reported in the LAR.

Item	F&O	Observation	Significance	Status & Resolution	Impact on EDG Completion Time
				Completion Time extension, which performed detailed HRA modeling on all of the risk important operator actions.	
31	HR-11, sub-element 27	Based on the operator action sensitivity study performed, there are several scenarios involving multiple human error events. Some of the dependencies appear to have been recognized, but it was not intuitively obvious how they were factored into the quantification of conditional HEPs (e.g., FDBLDOPATY). Several scenarios involve more than 4 HEPs, and this raises a question regarding how the operator actions are being placed within the model. The product of some of these multiple HEP scenarios result in total crew failure probabilities less than 1E-06, which appears to be optimistic.	A	CLOSED - A new dependency analysis has been completed that identifies all dependant combinations of operator actions and ensures that multiple combinations are not less than 1E-05.	The PRA model was changed as a result of this F&O and any impact on the results are already reported in the LAR.
32	HR-15, sub-element 17	The local actions in the switchover to containment sump recirculation are modeled as 4 actions that are easy to recall. In actuality there are 13 distinct actions and only 4 are given as critical. No justification is given for the non-critical steps. Even accepting that the other 9 actions are not critical, they would certainly affect the operator's ability to remember the steps. In general there doesn't appear to be any evidence for the non-criticality of tasks or that the	B	CLOSED - Recently, an update of the HRA model has been completed where all important operator actions were calculated using current industry standards.	The PRA model was changed as a result of this F&O and any impact on the results are already reported in the LAR.

Item	F&O	Observation	Significance	Status & Resolution	Impact on EDG Completion Time
		added complexity they introduce has been considered.			
33	QU-1, sub-element 1	This F&O relates to both guidance and documentation sub-elements of QU. A quantification notebook describing the following items needs to be created: • how the one-top CDF model is constructed (guidance); • how any technical adjustments are made to the top of the FT or in the systems below (beyond what is documented in the system and event tree notebooks) to allow quantification; • any special logic introduced to model sequences (flags, etc.); • supporting files (such as MUTEX, RECOVERY, .BE, .TC, etc), • summary input/output files; • results summary files and conclusions (See QU-5 also); • computer run parameters; • type of computer and operating system, list and version of executable codes used; • limitations of the code; • references to supporting model notebooks (ET, system, HRA, data) etc.	B	CLOSED - A Quantification Notebook was created detailing the Rev 1.2 and Rev 2.0 PRA model results. The notebook contains sufficient guidance for performing the process and sufficient detail to document the inputs and outputs of the process.	This is a documentation enhancement issue and has no impact on the PRA model used for the LAR.

Item	F&O	Observation	Significance	Status & Resolution	Impact on EDG Completion Time
		Modifications performed in the one-top fault tree, such as creation of the AFW-T fault tree from the full AFW tree, must be documented either in the quantification or system notebooks.			
34	QU-3, sub-element 8	The contribution of LOOP sequences that lead to loss of cooling water and instrument air could be greatly reduced if credit could be given to recovery of offsite power within the calculated time to core uncovery of 5 hours.	B	CLOSED - For the Rev 1.2 and higher models, recovery of offsite power was credited for the LOOP sequences that lead to loss of cooling water and instrument air.	The PRA model was changed as a result of this F&O and any impact on the results are already reported in the LAR.
35	QU-5, sub-element 31	The Peer Review supplemental guidance (draft subtier criteria) states that, for a category 3 classification for this sub-element, one must fullfill the following: "The accident sequence results by sequence, sequence types, and total should be reviewed and compared to similar plants to assure reasonableness and to identify any	B	OPEN – A Quantification Notebook was created detailing the Rev 1.2 PRA model results. The notebook contains a thorough evaluation of the quantification results meeting the standards in the Draft version of the "ASME PRA Standard" including review of top cutsets,	This is a documentation enhancement issue and has no impact on the PRA model used for the LAR.

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		exceptions. A detailed description of the Top 10 to 100 accident cutsets should be provided because they are be important in ensuring that the model results are well understood and that modeling assumption impacts are likewise well known. Similarly, the dominant accident sequences or functional failure groups should also be discussed. These functional failure groups should be based on a scheme similar to that identified by NEI in NEI 91-04, Appendix B." A summary of top sequences by initiating event was provided, as was a listing of risk-important systems and operator actions. Detailed descriptions of cutsets were not provided, nor was a comparison of results to similar plants.		dominant accident sequences, initiating events, importance measures, model asymmetries, and operator actions. Results from the Westinghouse MSPI Cross Comparison document related to Prairie Island will be addressed as part of the MSPI Project by December 2005. Once this is completed this F&O will be considered closed.	
36	QU-6, sub-element 27	Neither a quantitative uncertainty analysis nor a qualitative evaluation of significant sources of uncertainty are addressed.	B	OPEN – This activity will be completed as part of the data update, which will be completed by the end of 2005.	This is a documentation enhancement issue and has no impact on the PRA model used for the LAR.
37	MU-4, sub-element 6	PRA group procedure 3.001A requires evaluation of PRA results when the model is updated, and documentation in accordance with PRA group procedure 1.002A. The procedure	B	CLOSED – An extensive review of the Rev 1.2 and Rev 2.0 model results (top cutsets, dominant accident sequences, initiating	This is a documentation enhancement issue and has no impact on the PRA model used for the LAR.

Item	F&O	Observation	Significance	Status & Resolution	Impact on EDG Completion Time
		indicates that the evaluation must include a review of top cutsets and basic event importance measures to ensure that dominant contributors to risk are modeled accurately and that dependent operator actions are treated appropriately, with focus on understanding and addressing risk significant issues that have resulted from the latest requantification. For a full PRA update, consideration should also be given to reviewing more than just dominant contributors and top cutsets, depending on the extent of modeling change. For example, the in-progress Rev 2 model upgrade may produce results that will require a deeper review than an examination of top cutsets, top risk importance contributors, and overall CDF/LERF values.		events review, importance measures, model asymmetries, operator actions) has been performed and is documented in the Quantification Notebook. Fleet PRA procedures have also been developed and implemented which address the PRA model maintenance issues.	