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Subject: Relief Request 01-005
Request for Additional Information
McGuire Nuclear Station Units 1 and 2
Docket Nos. 50-369, 50-370

Reference: 1) Letter from Mr. H.B. Barron of Duke Energy to the NRC, Relief Request 01-005, dated June 26, 2001, 2) Letter from Mr. R.E. Martin of the NRC to Mr. H.B. Barron of Duke Energy, dated December 6, 2001

Duke Energy Corporation (Duke) on June 26, 2001 submitted Relief Request 01-005, which pertains to the "Application of Risk-Informed Methods to Inservice Inspection of Piping". In referenced item number 2 above, the NRC staff requested additional information. Duke's responses along with the corresponding requests are provided in the attachment.

Questions on this matter should be directed to Norman T. Simms, McGuire Licensing and Compliance, at (704) 875-4685.

Sincerely,

HB Barron

H. B. Barron

Attachment

A047

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Response to Request for Additional Information
Risk-Informed Inservice Inspection
McGuire Nuclear Station, Units 1 and 2
Duke Energy Corporation

January 2002

1. REQUEST:

One major step in the WCAP process is the identification of degradation mechanisms and the development of corresponding pipe failure frequencies. The requested Table 1 summarizes the qualitative results of this step by identifying the different degradation mechanisms, combinations of mechanisms, and the prevalence of the different mechanism. The calculated ranges in Table 1 summarize the quantitative results of the analysis. This information will illustrate how the degradation mechanism identification and failure frequency development step in the WCAP methodology was implemented, and provide an overview of the results generated. Please expand the current Table 3.4-1 to include the following information.

a) System	b) Degradation Mechanism/ Combination	c) Failure Probability range at 40 years with no ISI		d)Comments
		leak	disabling leak	

a) System: Each system included in the analysis.

b) Degradation Mechanism/Combination: Segment failure probabilities are characterized in the WCAP method by imposing all degradation mechanism in a segment (even if they occur at different welds) and the worst case operating conditions at the segment on a "representative" weld, and using the resulting failure probability for the segment. Please identify the dominant degradation mechanisms and combination of degradation mechanisms selected in each system. The reported mechanisms should cover all segments in the system. The table in the current submittal is not clear about which specific degradation mechanisms or combination of mechanisms are included in the leak estimates provided.

c) Failure Probability range at 40 years with no ISI: For each dominant degradation mechanism and combination of degradation mechanisms, please provide the range of estimates developed for the leak and disabling leak sizes as applicable. If multiple LOCA sizes are estimated for larger pipes reflecting the possibility of different size leaks, the frequency range of for size should be given. The table in the current submittal provided the range of leak estimates only.

d) Comments: These should provide further explanations and clarifications on the particular characteristics of the system/segments leading to the selection of the degradation mechanism(s). Other information that should be included is the identification of which degradation mechanism(s) are applied to socket welds, if a break calculation was needed to evaluate pipe whip constraints, and if the degradation mechanism is addressed by an augmented program.

RESPONSE:

System	Degradation Mechanism/ Combination	Failure Probability Range at 40 Years With No ISI		Comments
		Small Leak	Disabling Leak	
BB	Thermal Fatigue	2.38E-06 – 7.31E-05	SYS 2.15E-06 – 9.83E-05	Normal heat up / cool down
BW	Thermal Fatigue	6.14E-06 - 4.76E-05	SYS 7.5E-07 – 4.63E-05	Normal heat up / cool down
CA	Erosion Corrosion, Thermal Fatigue	1.21E-06 - 2.04E-03	SYS 3.30E-07 – 4.29E-04	Erosion Corrosion is addressed by FAC program.
CF	Erosion Corrosion, Thermal Fatigue	3.01E-07 - 1.12E-03	SYS 1.08E-07 – 2.46E-04	Erosion Corrosion is addressed by FAC program.
FW	Thermal Fatigue	2.43E-05 - 2.35E-04	SYS 3.12E-06 – 3.20E-05	Thermal Fatigue: The system has excellent water chemistry. There are no significant failure mechanisms at work within the system beyond the SRRA default mechanism of thermal fatigue which is insignificant given the low system temperatures.
KC	Stress Corrosion Cracking & Thermal Fatigue	6.78E-06 - 7.47E-05	SYS 4.54E-08 – 2.10E-04	Stress Corrosion Cracking: The system has some stress corrosion and material wastage history. Thermal Fatigue: Normal system heat-up and cool-down transients that are not very significant given relatively low system temperatures.
NC	Thermal Fatigue	1.15E-06 - 4.59E-03	SYS 1.01E-07 – 3.20E-03 SLOCA 9.64E-07 - 3.13E-03 MLOCA 9.64E-07 - 3.12E-03 LLOCA 1.31E-06 - 4.94E-05	Thermal Fatigue: a) Normal plant heat-up and cool-down cycles associated with high temperature piping. b) Some RCS branch lines have the potential for thermal stratification caused by turbulent penetration. c) Some RCS branch lines have the potential for thermal stratification caused by check valve leakage. d) Some RCS branch lines have the potential for thermal fatigue caused by rapid high temperature changes from relief valve actuation.

NC	Thermal Fatigue & Vibrational Fatigue	5.25E-06 - 9.05E-04	SYS 3.77E-06 SLOCA 2.13E-05 - 4.59E-04 MLOCA 1.76E-05	Thermal Fatigue: Normal plant heat-up and cool-down cycles associated with high temperature piping. Vibrational Fatigue: Some small lines have a potential for flow induced vibration effects. Other small lines have a potential for vibration effects due to pressurizer relief valve actuation.
NC	Thermal Fatigue & Waterhammer	1.77E-06 – 4.06E-05	SYS 8.09E-08 – 7.71E-05 SLOCA 9.16E-08 – 7.57E-05 MLOCA 8.79E-08 – 3.01E-05 LLOCA 9.62E-08	Thermal Fatigue: Normal plant heat-up and cool-down cycles associated with high temperature piping. Water Hammer: 1) Pressurizer relief valve lines subjected to PORV actuation have the potential for steam/water-hammer forces. 2) Volume control excess letdown line connection to RCS has the potential to experience a water hammer when the path is aligned (typically once at the beginning of an operational cycle). 3) Potential Pressurizer spray line water hammer when cold flow is introduced into a partially steam filled pipe. 4) Pressurizer relief valve header line subjected to PORV actuation has the potential for steam/water hammer forces.
ND	Thermal Fatigue	1.59E-05 - 6.56E-04	SYS 5.51E-06 – 9.85E-05	Thermal Fatigue: Normal plant heat-up and cool-down cycles associated with an interface with high temperature RCS piping.
ND	Thermal Fatigue & Vibrational Fatigue	4.62E-05 - 6.56E-04	SYS 1.06E-05 – 8.13E-05	Thermal Fatigue: Normal plant heat-up and cool-down cycles associated with an interface with high temperature RCS piping. Vibrational Fatigue: Segments of suction and discharge lines immediately adjacent to the ND system pumps and smaller branch lines off these segments have the potential for pump induced vibration.
ND	Thermal Fatigue & Water Hammer	4.47E-05 - 2.15E-04	SYS 2.43E-06 – 1.32E-04	Thermal Fatigue: Normal plant heat-up and cool-down cycles associated with an interface with high temperature piping. Water Hammer: Several segments had a previous history of many small events. The causing problem was corrected but this analysis treatment considers its past effects.

ND	Thermal Fatigue, Vibrational Fatigue, & Water Hammer	6.78E-05 - 2.15E-04	SYS 2.49E-06 – 1.34E-04	Thermal Fatigue: Normal plant heat-up and cool-down cycles associated with an interface with high temperature piping. Vibrational Fatigue: Segments of suction and discharge lines immediately adjacent to the ND system pumps and smaller branch lines off these segments have the potential for pump induced vibration. Water Hammer: Several segments had a previous history of many small events. The causing problem was corrected but this analysis considers its past effects.
NF	General Corrosion & Thermal Fatigue	2.32E-05 - 4.40E-05	SYS 1.54E-07 – 6.73E-06	General Corrosion: A low potential for corrosion was included in this closed loop, treated water system. Thermal Fatigue: There are no significant failure mechanisms at work within the system beyond the SRRA default mechanism of thermal fatigue which is insignificant given the low system temperatures.
NI	Stress Corrosion Cracking, Thermal Fatigue	2.45E-05 - 1.07E-02	SYS 1.39E-05 – 1.39E-03	Standby system becomes oxygenated over fuel cycle/ moderate temp./ possible PIV leakage.
NI	Stress Corrosion Cracking, Vibrational Fatigue, Thermal Fatigue	8.34E-05 - 9.09E-02	SYS 4.09E-05 – 6.50E-02	Standby system becomes oxygenated over fuel cycle/ elevated temp. proximate to NC interface/ possible PIV leakage
NI	Stress Corrosion Cracking, Vibrational Fatigue, Waterhammer, Thermal Fatigue	1.78E-04 - 3.01E-04	SYS 1.89E-05 – 2.31E-05	Oxygen / moderate temp. proximate to NC interface/ possible PIV leakage/ No history of waterhammer, but potential voiding issue in ND to NI piping.
NI	Thermal Fatigue	4.90E-07 - 1.78E-04	SYS 2.37E-06 – 1.23E-04	Normal heat up / cool down

NM	Thermal Fatigue	1.40E-05 - 4.50E-05	SYS 1.91E-05 – 8.17E-05	Thermal Fatigue: There are no significant failure mechanisms at work within the system beyond thermal fatigue caused by normal plant sampling frequency heat-up and cool-down transients.
NS	Vibratory Fatigue, Thermal Fatigue	6.69E-05 - 1.43E-04	SYS 9.72E-06 – 1.77E-05	Pump test vibration
NS	Waterhammer, Thermal Fatigue	6.69E-05	SYS 1.17E-06	Containment riser piping
NS	Thermal Fatigue	2.00E-05 - 9.69E-05	SYS 3.89E-06 – 7.85E-05	Normal heat up / cool down
NV	Stress Corrosion Cracking, Thermal Fatigue	1.91E-06 - 9.47E-02	SYS 2.58E-06 – 6.79E-02	Elevated temp proximate to NC system/ possible oxygen /loss of charging
NV	Stress Corrosion Cracking, Thermal Fatigue, Vibrational Fatigue	4.42E-04 - 1.65E-02	SYS 2.18E-05 – 9.78E-03 SLOCA 4.93E-03 – 7.62E-03	Charging pumps/ possible oxygen some areas/ leaking PIVs.
NV	Vibrational Fatigue, Thermal Fatigue	3.59E-05 - 7.64E-03	SYS 3.43E-05 – 1.34E-02 SLOCA 3.43E-05 – 1.34E-02 MLOCA 3.41E-05 – 1.34E-02	Letdown orifices
NV	Vibrational Fatigue, Waterhammer, Thermal Fatigue	3.42E-04 - 3.09E-03	SYS 6.79E-05 – 5.92E-04	Letdown orifices
NV	Thermal Fatigue	5.05E-06 - 2.62E-05	SYS 2.17E-06 – 1.72E-05 SLOCA 1.71E-06 – 1.44E-05 MLOCA 4.03E-06	Normal heat up / cool down
RF	General Corrosion & Thermal Fatigue	N/A – The whole system is of No Consequence.	N/A	An Expert Panel decision demoted this entire system to that of a "no consequence" failure status.

RN	General Corrosion & Thermal Fatigue	1.11E-02	SYS 1.11E-02	General Corrosion: The system has a relatively high material wastage potential due to its corrosion history. General corrosion is addressed by the FAC Program. Thermal Fatigue: Normal system heat-up and cool-down transients that are not very significant given relatively low system temperatures.
RV	General Corrosion & Thermal Fatigue	4.20E-03 - 1.11E-02	SYS 4.20E-03 – 1.11E-02	General Corrosion: The system has a relatively high material wastage potential due to its corrosion history. Thermal Fatigue: Normal system heat-up and cool-down transients that are not very significant given relatively low system temperature
SA	Thermal Fatigue	1.99E-07 - 2.48E-05	SYS 5.40E-08 – 7.81E-05	Thermal Fatigue: In this dry steam system there are no significant failure mechanisms at work beyond thermal fatigue caused by normal plant heat-up and cool-down transients.
SA	Thermal Fatigue & Water Hammer	1.99E-07 - 2.48E-05	SYS 1.60E-05 – 7.62E-05	Thermal Fatigue: In this dry steam system there are no significant failure mechanisms at work beyond thermal fatigue caused by normal plant heat-up and cool-down transients. Water Hammer: Industry experience with main steam condensate drain line operation indicates a potential for creating steam propelled condensate slugs.
SM	Thermal Fatigue	6.15E-09 - 4.76E-05	SYS 8.61E-09 – 4.63E-05	Thermal Fatigue: In this dry steam system there are no significant failure mechanisms at work beyond thermal fatigue caused by normal plant heat-up and cool-down transients.
SV	Thermal Fatigue	1.99E-07 - 2.48E-05	SYS 5.40E-08 – 3.90E-05	Thermal Fatigue: In this dry steam system there are no significant failure mechanisms at work beyond thermal fatigue caused by normal plant heat-up and cool-down transients.
VB	General Corrosion	5.79E-05	SYS 7.78E-05	General Corrosion: In this stainless steel air system there are no significant failure mechanisms at work.
VI	Thermal Fatigue	4.65E-05 - 4.74E-05	SYS 7.34E-05 – 7.72E-05	Air system – normal heat-up and cool down.

VP	Thermal Fatigue	N/A – The whole system is of No Consequence.	N/A	An Expert Panel decision demoted this entire air system to a "no consequence" failure status.
VQ	Thermal Fatigue	3.63E-05	SYS 4.77E-06	Thermal Fatigue: In this air system there are no significant failure mechanisms at work beyond thermal fatigue cause by normal plant heat-up and cool-down transients.
VS	Thermal Fatigue	4.65E-05	7.34E-05	Air system – normal heat-up and cool down.
WL	Stress Corrosion Cracking & Thermal Fatigue	4.91E-03 - 6.36E-02	SYS 5.25E-05 – 1.33E-02	Stress Corrosion Cracking: The system is exposed to numerous chemical contents related to various waste streams that may contribute to a potential for stress corrosion. Thermal Fatigue: Normal system heat-up and cool-down transients that are not very significant given relatively low system temperatures.
YM	Thermal Fatigue	5.77E-05	SYS 8.23E-05	Thermal Fatigue: There are no significant failure mechanisms at work within the system beyond the SRRA default mechanism of thermal fatigue which is insignificant given the low system temperatures.

Note: The following comment is applicable to all the systems shown in the above table. Degradation mechanism identification was made independently of the type of weld (i.e. socket or butt).

2. REQUEST:

Another major step in the WCAP process is assignment of segments into safety significance categories based on an integrated decision making process, and the selection of segments for inspection locations. The requested Table 3 summarizes the results of the safety significance categorization process as determined by the quantitative criteria, by the expert panel's deliberation on the medium safety significant segments, and by the expert panel's deliberations based on other considerations. The summarizing information requested in Table 3 will provide an overview of the distribution of the safety significance of the segments based on the quantitative results, and the final distribution based on the integrated decision making. Each segment has four RRWs calculated, a CDF with and without operator action, and a LERF with and without operator action. Please provide the following Table.

System	Number of segments with any RRW > 1.005	Number of segments with any RRW between 1.005 and 1.001	Number of segments with any RRW between 1.005 and 1.001 placed in HSS	Number of segments with all RRW < 1.001	Number of segments with all RRW < 1.001 selected for inspection	Total number of segments selected for inspection

RESPONSE:

For the Unit 1 Table see page 10.
For the Unit 2 Table see page 11.

Note: Minor changes to the column headings in the table are provided in the response based on Duke's interpretation and application of the WCAP. The following categorizations were applied to the quantitative risk ranking results prior to the expert panel sessions:

$RRW \geq 1.005$ is HSS (high)
$1.001 \leq RRW < 1.005$ is MSS (medium)
$RRW < 1.001$ is LSS (low)

Summary of Risk Evaluation and Expert Panel Categorization Results
McGuire Unit 1

System	Number of segments with any RRW ≥ 1.005	Number of segments with any 1.001 ≤ RRW < 1.005	Number of segments with all RRW < 1.001	Number of segments with any 1.001 ≤ RRW < 1.005 selected for inspection (High Safety Significant Segments)	Number of segments with all RRW < 1.001 selected for inspection (High Safety Significant Segments)	Total number of segments selected for inspection (High Safety Significant Segments)
BB	0	0	24	0	0	0
BW	0	0	8	0	0	0
CA	0	0	36	0	0	0
CF	0	0	52	0	0	0
EMF	0	0	1	0	0	0
FW	0	0	19	0	0	0
GN	0	0	20	0	0	0
IAE	0	0	1	0	0	0
KC	0	0	34	0	0	0
NB	0	0	2	0	0	0
NC	29	22	59	7	1	37 (Note 1)
ND	0	0	74	0	2	2
NF	0	0	20	0	0	0
NI	2	14	114	5	5	12
NM	0	0	37	0	0	0
NS	6	8	28	0	0	6
NV	13	9	219	6	52	71
RF	0	0	4	0	0	0
RN	0	4	4	0	0	0
RV	4	0	20	0	0	4
SA	0	0	14	0	0	0
SM	0	0	42	0	0	0
SV	0	0	8	0	0	0
VB	0	1	3	0	0	0
VE	0	0	7	0	0	0
VI	0	0	34	0	0	0
VP	0	0	18	0	0	0
VQ	0	0	8	0	0	0
VS	0	0	4	0	0	0
VX	0	0	2	0	0	0
WG	0	0	1	0	0	0
WL	3	1	15	0	0	3
YA	0	0	4	0	0	0
YM	0	0	5	0	0	0
Total	57	59	941	18	60	135

Note 1: One segment was not originally HSS, but was added as a result of change in risk evaluations. See RAI #6 on page 24.

Summary of Risk Evaluation and Expert Panel Categorization Results McGuire Unit 2						
System	Number of segments with any RRW ≥ 1.005	Number of segments with any 1.001 ≤ RRW < 1.005	Number of segments with all RRW < 1.001	Number of segments with any 1.001 ≤ RRW < 1.005 selected for inspection (High Safety Significant Segments)	Number of segments with all RRW < 1.001 selected for inspection (High Safety Significant Segments)	Total number of segments selected for inspection (High Safety Significant Segments)
BB	0	0	24	0	0	0
BW	0	0	8	0	0	0
CA	0	0	36	0	0	0
CF	0	0	52	0	0	0
EMF	0	0	1	0	0	0
FW	0	0	19	0	0	0
GN	0	0	20	0	0	0
IAE	0	0	1	0	0	0
KC	0	0	34	0	0	0
NB	0	0	2	0	0	0
NC	24	30	56	11	1	36
ND	0	0	74	0	4	4
NF	0	0	20	0	0	0
NI	2	13	115	5	5	12
NM	0	0	37	0	0	0
NS	4	10	28	2	0	6
NV	13	8	220	6	48	67
RF	0	0	4	0	0	0
RN	0	4	4	0	0	0
RV	4	0	20	0	0	4
SA	0	0	14	0	0	0
SM	0	0	42	0	0	0
SV	0	0	8	0	0	0
VB	0	1	3	0	0	0
VE	0	0	7	0	0	0
VI	0	0	34	0	0	0
VP	0	0	18	0	0	0
VQ	0	0	8	0	0	0
VS	0	0	4	0	0	0
VX	0	0	2	0	0	0
WG	0	0	1	0	0	0
WL	3	0	16	0	0	3
YA	0	0	4	0	0	0
YM	0	0	5	0	0	0
Total	50	66	941	24	58	132

3. REQUEST:

Another major step in the WCAP process is development of the consequences of segment ruptures. The WCAP methodology requires that a summary of the consequences be developed for each system and provided to the expert panel during their deliberations. Please provide this summary for each system. The summary will illustrate that the appropriate types of consequences (i.e., initiating events, mitigating system failure, and combinations) are included in the evaluation and will provide an overview of the results of the step.

RESPONSE:

Per the WCAP requirements, Duke provided a summary of the segment rupture consequences for each system and distributed this information to the Expert Panel for their deliberations. The following was provided:

System	Summary of Consequences
BB – Boiler Blowdown	The BB main header piping segment failures can be grouped into three categories: 1. Failures occurring between the SG and the inside containment isolation valve 2. Failures occurring between the inside containment isolation valve and the containment wall 3. Failures occurring outside containment. For the first category, a break will result in a loss of the steam generator contents inside containment that can not be isolated. The resulting release will cause a high containment pressure signal and a loss of SG inventory such that the containment isolation valves (BB1B, BB2B, BB3B, BB4B, BB5A, BB6A, BB7A, and BB8A) will close. The event will be considered as a secondary side line break inside containment initiator (this initiator also assumes a loss of the respective SG). The consequences will be the same with or without operator action. For the second category, a break will result in some loss of the steam generator contents inside containment before containment isolation occurs. In addition, the mass release will cause a pressure increase inside containment. At a 1 psig increase, safety injection is initiated and containment isolation valves will close. This event will thus be similar to an inadvertent safety injection signal initiator. The consequences will be the same with or without operator action. For the third category, a break will result in some loss of the steam generator contents outside containment. A low-low level in the SG will initiate Auxiliary Feedwater, subsequently causing the containment isolation valves to close and the reactor to automatically trip. This event will thus be considered as a reactor trip initiator. The

	consequences will be the same with or without operator action.
BW – SG Wet Layup	A failure in one of the four piping segments under consideration will cause a release of steam into containment that can not be isolated. The event will be considered as a secondary side line break inside containment initiator. The consequences will be the same with or without operator action.
CA – Auxiliary Feedwater	Isolable breaks outside containment without operator action will be treated as a main feedwater line break with some loss of flow from the TDP and / or a MDP. Per the PRA summary report, this initiator normally assumes a loss of the respective SG; however, with operator action, breaks occurring on the 'MDP supply side' can have CA restored via the TDP. Non-isolable breaks outside containment will be considered as a main feedwater line break initiator, both with and without operator action. Breaks inside containment will be considered as a secondary side line break inside containment initiator, both with and without operator action. This initiator also assumes a loss of the respective SG. There are no flow restricting devices in the TDP supply lines to the SGs. However, control valves CA64AB, 52AB, 48AB,and 36AB have travel stops which prevent pump runout when the TDP starts (thus requiring no operator action to throttle). Likewise, MDP supply control valves CA60A, 56A, 44B, and 40B have travel stops to prevent pump runout. Therefore, breaks in the 4" and 6" piping would result in a loss of TDP flow to the affected SG only. A loss of the 'B' and 'C' SGs together will result in a loss of steam supply to the CA TDP. In terms of indirect effects, it is postulated that jet impingement / spray from a failure of the elbow at containment penetration M262 would fail the safety-related cable on column FF53. This, in turn, could cause a reactor trip (MSIVs closing) as well as a loss of SG PORVs SV7ABC, SV13AB.
CF – Main Feedwater	Isolable breaks outside containment can be treated in one of two ways: • The first signal seen is the hi-hi doghouse level, which causes feedwater isolation with a subsequent reactor trip. The break gets isolated, thereby resulting in no depressurization and no safety injection (S/I). • Second, the first signal seen is a reactor trip. The break does not get isolated and the resulting depressurization generates an S/I signal prior to getting a feedwater isolation signal. This scenario would resemble an inadvertent S/I actuation. This scenario should be the more conservative selection.

	Therefore, isolable pipe breaks in the CF lines outside containment will be treated as an Inadvertent Safety Injection Actuation initiator. Non-isolable breaks outside containment will be considered as a Main Feedwater Line Break. Breaks in the 18" / 16" lines inside containment will be considered as a Secondary Side Line Break Inside Containment initiator. The PRA model assumes that the affected SG is unavailable and that Main Feedwater is not restored. In addition, any events rendering either the 'B' or 'C' SG unavailable will eliminate one of two steam supplies to the CA TDP (accounted for in the MFLB and SSLB events). In terms of indirect effects, it is postulated that jet impingement / spray from a failure of the elbow at containment penetration M262 would fail the safety-related cable on column FF53. This, in turn, could cause a reactor trip (MSIVs closing) as well as a loss of SG PORVs SV7ABC, SV13AB.
EMF – Electrical Process and Area Radiation Monitoring	The EMF system was determined to be "No Consequence" for Risk Informed Inservice Inspection.
FW – Refueling Water	A failure of the larger piping from the FWST results in a loss of all ECCS during the injection phase. For FW piping segments passing through containment, a failure of one of these segments results in a loss of the containment pressure boundary.
GN – Nitrogen	The GN system was determined to be "No Consequence" for Risk Informed Inservice Inspection.
IAE – Containment Personnel Airlock	The IAE system was determined to be "No Consequence" for Risk Informed Inservice Inspection.
KC – Component Cooling	The portions of the KC system containing Class 1 and 2 piping perform the following functions: 1. Supply and discharge piping for RCP Thermal barriers 2. Supply and return lines to the RCP Motor Coolers 3. Cooling for the NV Excess Letdown HX 4. Supply and Return line from Reactor Coolant Drain Tank 5. Misc. KC drains going to the KC Drain Tank In order to determine whether a failure in the one of these segment sets would cause an initiating event or system failure, it is necessary to look at the available surge tank volume required to maintain NPSH. Per the KC Design Basis Document, the surge tank was sized based on the expansion volume from the system plus the volume obtained from a 50 gpm leak for 33 minutes before the operator has to take action. This is based upon the minimum operating surge tank level. For normal operation, the tank level is higher; hence, the operator will have longer than 33 minutes to respond.) The surge tank is divided into two compartments – 1 per train –

	therefore, a draindown of only one side would occur. Thus, the consequence without operator action will be a loss of the operating KC train since NPSH can not be maintained for a 24-hr. mission time. For a break in the RCP thermal barrier piping, system inventory will drain into the containment sump. The control room will most likely see a low flow alarm which will cause the operator to evaluate its cause. It is assumed that a combination of the low flow alarm, an increasing containment sump level, and a falling KC Surge Tank level will be sufficient to alert the operator as to the source of the system leakage. It is further anticipated that the operator will then proceed to a controlled shutdown given that seal injection is available. A break in the supply line to the RCP Bearing Coolers and Thermal Barriers will require the closure of 1KC338B to isolate flow. Per Ref. 10.7, if flow is lost to all four RCPs for more than 20 – 30 minutes, the operators will have to trip the reactor. A failure of the piping supplying cooling to the NV Excess Letdown HX is assumed to have no consequence (other than a loss of the containment isolation boundary) with or without operator failure since, from the DBD, this line is normally closed for all modes of operation, including LOCAs. The Reactor Coolant Drain Tank is not modeled in the PRA. However, if a segment in this area failed, the operator may not necessarily be aware of where the failure occurred. Therefore, a failure of this line will result in a loss of KC without operator action. It is conservatively assumed that the operator will isolate flow to the RCP motor bearing coolers in an effort to locate the break. Finally, a failure in the miscellaneous KC drain line piping is not normally expected to have any severe consequences with or without operator failure. Since many of these lines are normally isolated and the remaining lines (valve leakoffs, etc.) would have very minimal flowrates, system failure would not be a concern. However, it will conservatively be assumed that a failure of these segments without operator action will result in a loss of KC. Again, it is conservatively assumed that the operator will isolate flow to the RCP motor bearing coolers in an effort to locate the break. If, it is determined that these segments are highly risk significant, they will be re-analyzed.
NB – Boron Recycle	The NB system was determined to be "No Consequence" for Risk Informed Inservice Inspection.
NC –Reactor Coolant	Depending upon location and size, segment failure will result in either a small, medium, or large break LOCA. In addition, failures of other functions such as cold leg

	injection, loss of pressurizer spray, and charging could occur.
ND – Residual Heat Removal	Depending upon location, segment failure (without operator action) results in a loss of one or more of the following functions: • LPI, LPR, and RHR • HPI, HPI charging, HPR, HPR charging • Containment spray injection and recirculation • Auxiliary containment spray • Sump inventory • Loss of FWST outside containment Operator action, in most cases, would isolate the faulted ND train. For ND piping segments passing through containment, their failure will result in a loss of the containment pressure boundary. In terms of indirect effects, the ND piping segments outside containment were reviewed for possible consequences resulting from postulated pipe whip and / or jet impingement / spray events. Most of the effects from these failures either did not have a great impact on core damage potential or were incorporated by direct effect analyses.
NF – Ice Condenser	The segment failure consequences deal solely with a loss of the containment isolation boundary.
NI – Safety Injection	Depending upon location, segment failure can result in a loss of one or more of the following functions: • Loss of accumulator injection • Loss of nitrogen backup to PORV • High Pressure Injection • High Pressure Recirculation • Low Pressure Injection • Low Pressure Recirculation • RHR • Loss of FWST inventory outside containment, NI, NV, ND, and NS Pumps for Injection and Recirculation In addition, failure of piping segments passing through containment would result in a loss of the containment pressure boundary. In terms of indirect effects, it is postulated that jet impingement / spray from a failure of segment NI-030A would fail all cables out of 1ATB183. This has the effect of failing valves NI-136B and NI-185A. Two other jet impingement / spray events were postulated, but they do not have an effect on core damage.
NM – Nuclear Sampling	The NM System takes samples from / interfaces with many different systems. These are analyzed below:

	• NC System – There are four tie-ins to this system: Loop 1, Loop 4, Pressurizer water, Pressurizer steam. All four tie-ins are downstream of pressure reducing orifices, thereby effectively making these segments 'no consequence' per the RI-ISI segment definition guidelines. The portion of these sampling lines that penetrate containment, however, would result in a loss of containment boundary. • NI Accumulators – The sampling line for each accumulator combines into a common header that then penetrates containment. A break in one of the individual lines results in a loss of that accumulator's injection function. In addition, a failure of the 'A' or 'B' accumulator results in a loss of nitrogen backup to either PORV NC34A or NC32B. The portion of this line that penetrates containment, however, would result in a loss of containment boundary. • NV System (VCT) – A loss of this segment would result in a loss of overpressure to the NV Volume Control Tank (VCT). Per discussions with the NV System engineer, the loss of overpressure will cause an increase in the RCP # 1 seal leakoff flow while decreasing flow to RCP seal # 2. Lo-level in the VCT initiates makeup from the reactor makeup control system (a subsystem of NV). If the reactor makeup control system is unable to provide sufficient makeup to keep the VCT level from falling to a lower level, a lo-level alarm is actuated. A lo-lo level signal causes the suction of the NV charging pumps (normally a Centrifugal Charging Pump) to be transferred to the Refueling Water Storage Tank (FWST). The operator will be alerted via either a low or lo-lo VCT pressure alarm (20 psig and 14 psig, respectively) or an alarm on decreasing RCP #2 seal standpipe level. As this point, it is expected that the operator will perform a controlled shutdown. It should also be noted that, with the VCT at atmospheric conditions, and assuming normal charging flowrates at nominal temperature, there is sufficient NPSH available such that cavitation is not a concern. Thus, failure of this piping segment will not result in any immediate consequences without operator action, but could eventually lead to a controlled shutdown with operator action. • Steam Generators / BB System – These lines are used for sampling the secondary side water chemistry. Breaks in these lines can be divided into 3 categories:

	1. Failures occurring between the SG and the inside containment isolation valves 2. Failures occurring between the inside containment isolation valves and the containment wall 3. Failures occurring outside containment. For the first category, a break will result in a loss of the steam generator contents inside containment that can not be isolated. The resulting release will eventually cause a high containment pressure signal and a loss of SG inventory such that the containment isolation valves (NM187A, NM190A, NM191B, NM197B, NM200B, NM201A, NM2207A, NM210A, NM211B, NM217B, NM220B, and NM221A) will receive a signal to close. The event will be considered as a secondary side line break inside containment initiator (this initiator also assumes a loss of the respective SG). The consequences will be the same with or without operator action. For the second category, a break will result in some loss of the steam generator contents inside containment before containment isolation occurs. In addition, the mass release will cause a pressure increase inside containment. At a 1 psig increase, safety injection is initiated and containment isolation valves will close. This event will thus be similar to an inadvertent safety injection signal initiator. The consequences will be the same with or without operator action. For the third category, a break will result in some loss of the steam generator contents outside containment. A low-low level in the SG will initiate Auxiliary Feedwater, subsequently causing the containment isolation valves to close and the reactor to automatically trip. This event will thus be considered as a reactor trip initiator. The consequences will be the same with or without operator action. The portion of these sampling lines that penetrate containment will result in a loss of containment boundary.
NS – Containment Spray	A failure in the main header piping on the suction side of the NS Pumps is assumed to create a diversion flow to all ECCS pumps due to its size (12”). A break in the main header on the pump discharge side of one train is not assumed to fail the opposite train. Per discussions with the NS System engineer, there should be minimal effect on the train without the pipe break.

	It is assumed that breaks in the 8-in. auxiliary spray lines will cause a flow diversion in the corresponding ND System train.
NV – Chemical and Volume Control	Due to the complexity of the NV System, a myriad of consequences can occur depending on pipe segment location. Most notable are: • Loss of one or both NV trains • Loss of recirculation • Loss of seal injection to one or more RCP seals • Loss of all borated water to ECCS pumps In addition, failure of piping segments passing through containment would result in a loss of the containment pressure boundary. In terms of indirect effects, the NV piping segments outside containment were reviewed for possible consequences resulting from postulated pipe whip and / or jet impingement / spray events. It is postulated that jet impingement / spray from a failure segments NV-011A and NV-065 would fail all cables out of 1ATB182 and 1ATB183, respectively. This has the effect of failing valves NI-136B and NI-185A. A pipe whip from segment NV-065 will also result in a loss of NV and sump recirculation.
RF – Fire Protection	The segment failure consequences deal solely with a loss of the containment isolation boundary.
RN – Nuclear Service Water	The piping segments of concern are located in the supply and return lines for the RCP Motor Air Coolers. A failure in the main supply line will cause a reactor trip (due to a direct loss of flow to the RCP motor coolers) and a loss of the containment pressure boundary. A failure in the main return line will result in a loss of the containment pressure boundary only. Operator action would involve isolating RN flow to the RCP Motor Coolers.
RV – Containment Ventilation Cooling Water	The failure consequences are very similar to those for RN. A failure in the main supply line will cause a reactor trip (due to a direct loss of flow to the RCP motor coolers) and a loss of the containment pressure boundary. The only additional consequence is the loss of the RV backup cooling to the RCP motor coolers.
SA – Main Steam Supply to Auxiliary Equipment	The portion of SA piping to be analyzed involves the steam supply from the 'B' and 'C' SM headers to the CA TDPs. Typically, upon receipt of a 2/4 low-low level signal in any two SGs, normally-closed AOVs SA48ABC and SA49AB will open to admit steam to the TDP. Each supply line contains a check valve such that a rupture in one header will not fail the other header. Thus, for pipe breaks upstream of the AOVs, the associated SM header will depressurize, thereby eventually causing the valves to open. However, assuming the check valves function properly, the affected header will be isolated, thereby

	allowing steam from the 'healthy' header to proceed to the TDP. For pipe breaks downstream of the AOVs, the consequences would be considered as a mitigator only since some other initiating event would have occurred prior to CA actuation.
SM – Main Steam	A rupture of the main steam header piping will cause the Main Steam Isolation Valves (MSIVs) to close on low steam pressure and / or hi-hi containment pressure. In addition, the break would cause a rapid cooling of the RCS and initiation of safety injection. The affected SG is assumed not to be available for heat removal, however, since continued feeding would aggravate overcooling of the RCS. The piping segments in question are upstream of the MSIVs. Thus, except for a few segments, the pipe breaks are not isolable from either inside or outside the containment. Therefore, breaks inside containment will be treated as a secondary side line break initiator while breaks outside containment will be treated as a steam line break initiator. For the few segments that are isolable, their failure with a successful isolation will look more like an inadvertent initiation of the ECCS Systems. Ruptures of the SM lines going to the 'B' and 'C' SGs will also cause a failure of that line's steam supply to the CA Turbine-Driven Pump. However, since these SM lines are redundant, a failure of one header will not cause a loss of the CA TDP function. For all of the smaller diameter SM piping connected to the main header, it is assumed that failure of this piping will also cause depressurization of the SG similar to the failure of the header piping (the progression just may take longer). Thus, these segments will be analyzed with the appropriate initiator, depending upon location. The PRA Secondary Side Line Break initiator (T6) and the Main Steam Line Break initiator (T8) are assumed to make the affected SG unavailable as a heat sink as well as fail 1 out of 2 TDP steam supplies.
SV – Main Steam Vent to Atmosphere	The SV System segments of interest consist of the piping for each header's PORV and associated isolation valve. Closing the respective PORV isolation valve can isolate these segments; therefore, successful segment isolation will resemble an inadvertent initiation of the ECCS Systems. Otherwise, the failure will progress to SG failure as outlined above for the SM header.
VB – Breathing Air	The segment failure consequences deal solely with a loss of the containment isolation boundary.
VE – Annulus Ventilation	The VE System Containment isolation valves close upon receipt of an S_T signal. The segment failure consequences deal solely with a loss of the containment isolation boundary.
VI – Instrument Air	If a break in an instrument air line were to occur, the

	system pressure would begin to decrease. Upon reaching 90 psig, a VI low-pressure alarm will cause the diesel-powered VI compressors to autostart, thus providing makeup capacity. However, it is not clearly known what size line break would result in the loss of system pressure regardless of makeup capacity. Per discussions with the VI system engineer, it was judged that compressor capacity would be unable to maintain pressure with break sizes in the 1-1/2" to 2" range. For consequences without operator action, break sizes from ¾" to 2" are assumed to fail VI; whereas, pipe breaks ½" and less are assumed not to fail the system (makeup capacity is sufficient to maintain system pressure). Furthermore, not all of the pipe breaks are readily isolable. Such failures will result in a loss of instrument air initiator with or without operator action.
VP – Containment Purge	The VP System is not used during accident conditions. The VP System containment isolation valves and dampers close upon receipt of an S_T signal. These valves and dampers fail closed on a loss of instrument air pressure. The segment failure consequences deal solely with a loss of the containment isolation boundary.
VQ – Containment Air Release and Addition	The VQ System is not used during accident conditions. Because the VQ System runs intermittently during power operation, its containment isolation valves close upon receipt of an S_T signal. The segment failure consequences deal solely with a loss of the containment isolation boundary.
VS – Station Air	The only consequences for this system are related to the loss of the containment penetration boundary.
VX – Containment Air Return and Hydrogen Skimmer	The VX system was determined to be "No Consequence" for Risk Informed Inservice Inspection.
WG – Waste Gas	The WG system was determined to be "No Consequence" for Risk Informed Inservice Inspection.
WL – Liquid Radwaste	The WL System is not used during accident conditions. The WL System containment isolation valves close upon receipt of an S_T signal. The segment failure consequences deal solely with a loss of the containment isolation boundary.
YA – Chemical Addition	The piping segments in question are normally isolated. Therefore, they are all considered to have no consequence of failure.
YM – Demineralized Water	The YM System is not used during accident conditions. The YM System containment isolation valves close upon receipt of an S_T signal. The segment failure consequences deal solely with a loss of the containment isolation boundary.

4. REQUEST:

Please add the statement that the sensitivity study to address uncertainty as described on page 125 was performed, and identify how many segments' RRW increased from below 1.001 to greater than or equal to 1.005. If the sensitivity study was not performed, provide a description and justification of any deviation.

RESPONSE:

The sensitivity study to address uncertainty as described on page 125 of the WCAP was performed. The RRW for LERF with Operator Action increased from below 1.001 to greater than or equal to 1.005 for 5 segments on Unit 1 and 4 segments on Unit 2.

5. REQUEST:

Please state that the change in risk calculations were performed according to all the guidelines provided on page 213 of the WCAP or provide a description and justification of any deviation. Many submittals using the WCAP methodology are deviating from one of the guidelines (third bullet from the top) insofar as they are taking credit for leak detection for systems other than the RCS system. If you have also taken credit for leak detection in non-RCS piping, please describe the characteristic of the piping and the justification for taking leak detection credit.

RESPONSE:

The change in risk calculations were performed according to all the guidelines provided on page 213 of the WCAP.

Some segments in the ND, NI, NM and NV systems take credit for leak detection. All the segments that take credit for leak detection are located inside the containment vessel where several plant conditions are monitored by systems that could detect leakage. These systems include the containment floor and equipment sumps, containment radiation monitors, containment humidity instrumentation, containment pressure instrumentation, and the ventilation unit condensate drain tank level. Indications from these sources can give signs of leakage and would prompt an Operations and Engineering evaluation of the cause.

6. REQUEST:

The quantitative change in risk results are adequately summarized in the current template tables 3-5 and 3-10. Please state that all four criteria for accepting the final selection of inspection locations provided on page 214 and 215 in WCAP-14572 Rev. 1-NP-A were applied. If all four criteria were not used, please provide a description and justification of the deviation. If comparison with any of the criteria indicated that "reevaluation" of the selected locations was needed, please identify the criteria that required the reevaluation and summarize the results of the reevaluation. If the results of the reevaluation can be found in the footnotes of Table 5-1, please refer to the footnotes.

RESPONSE:

All four criteria for accepting the final selection of inspection locations provided on page 214 and 215 in WCAP-14572 Rev. 1-NP-A were applied. Comparison of the Unit 1 NC (Reactor Coolant) system results to the criteria indicated this system needed to be reevaluated based on an increase in system risk for CDF with and without operator action. One inspection was added to the Unit 1 NC system which resulted in a risk decrease for the system. The addition of this NC inspection is identified in Table 5-1 by footnote d.

7. REQUEST:

Briefly describe the qualifications, experience, and training of the users of the SRRA code on the capabilities and limitations of the code.

RESPONSE:

The engineering team established to perform the failure probability evaluation using the SRRA code consisted of or had access to and support from ISI, NDE, materials, stress analysis, and system engineering. The team was trained by Westinghouse in the failure probability assessment methodology and in the Westinghouse structural reliability and risk assessment (SRRA) code, including identification of the capabilities and limitations of the code as described in WCAP-14572, Revision 1-NP-A, Supplement 1. Westinghouse also reviewed the SRRA work performed by the engineering team to ensure the appropriate and consistent application of the code.

8. REQUEST:

Section 2.2 of the submittal states that augmented programs remain unchanged, but augment programs may have an impact on the results. Please provide the following information regarding the treatment of augmented programs during the RI-ISI program development.

a) Treatment of augmented program inspections during categorization is described on page 80 (Section 3.5.5) of WCAP-14572, Rev. 1-NP-A. Please add the statement that the effects of ISI of existing augmented programs are included in your calculations used to categorize the segments or provide a description and justification of any deviation.

b) When the SRRA code is used for calculating failure probabilities for FAC, please describe if calculations were coordinated with the existing plant program since the code requires input that can be obtained from the knowledge gained from ongoing monitoring and evaluations of wall thinning rates.

RESPONSE:

a) The effects of ISI of existing augmented programs are included in calculations used to categorize segments.

b) The General Office engineer responsible for coordinating the Flow Accelerated Corrosion program provided information concerning the FAC corrosion rate of piping within the scope of the RI-ISI Piping program. The current monitoring program shows that FAC occurring on the in-scope piping has rates so low as to be generally immeasurable. No history of failures in the piping under the scope of the program was noted. Carbon steel piping inside the containment crane wall was replaced by FAC resistant piping at the time of steam generator replacement, thereby rendering it immune to FAC.

A FAC corrosion rate of 1mil per year was used. This value reflects the success of the actions and programs at McGuire to mitigate FAC damage. However, this value also maintains a certain degree of conservatism due to the knowledge that FAC occurs under certain conditions in carbon steel piping.

Using Guidance document directions, a degradation rate of 1 mil per year translates into a SRRA wastage input of 0.1. Branch lines and piping sections that experienced intermittent, but potentially high velocity flows during short times such as start-up were assigned SRRA values half the normal value, or 0.05.

9. REQUEST:

Please confirm that SRRA code was only used to calculate failure probabilities for the failure modes, materials, degradation mechanisms, input variables and uncertainties it was programmed to consider as discussed in the WCAP Supplement 1, page 15. For example, SRRA code should only be applied to standard piping geometry (circular piping geometry with uniform wall thickness). If the code was applied to any non-standard geometry, please describe how the SRRA inputs were developed.

RESPONSE:

The SRRA code was only used to calculate failure probabilities for the failure modes, materials, degradation mechanisms, input variables, and uncertainties it was programmed to consider as discussed in the WCAP Supplement 1, page 15. The code was applied only to circular pipe geometries with uniform wall thickness.

10. REQUEST:

Please describe any sensitivity studies performed to support the use of the SRRA code.

RESPONSE:

A simplistic sensitivity study was conducted to develop the appropriate SRRA input values for IGSCC. This study was necessary because the SRRA software proved highly sensitive to small increases in the input value. The intent was to determine what values would reasonably reflect a PWR with no history of IGSCC degradation while maintaining some conservatism that potential degradation could exist, but has not yet been detected. The approach was to establish a minimal, but not necessarily zero potential for IGSCC based on parameters such as oxygen content and temperature of the fluid in the pipe, and apply that logic consistently to all systems. A matrix was developed containing estimated SRRA values for IGSCC based on a few broad ranges of oxygen and temperature. Locations exposed to both high temperature and oxygenated water were assigned values of 0.1 to 0.05, resulting in relatively high failure probabilities. Locations with no oxygen or ambient temperature were assigned the minimal value of 0.001. In-between values were estimated as appropriate. The values in the matrix were applied for those systems fabricated from stainless steel and containing borated water.

11. REQUEST:

Please provide the total number of Class 1 butt welds and socket welds, the percentage of Class 1 butt welds selected for volumetric inspection, and the percentage of Class 1 socket welds selected for inspection in the RI-ISI program. If the total number of socket welds is not readily available, an estimate of the number is acceptable.

RESPONSE:

System	Unit	Total Number of Class 1 Butt Welds	Total Number of Class 1 Socket Welds	Percentage of Class 1 Butt Welds Selected for Volumetric Inspection	Percentage of Class 1 Socket Welds Selected for Inspection (* See Note)	Comments
NC	1	292	196	9	36	34 of 37 HSS Segments are Class 1
	2	276	194	9	31	34 of 36 HSS Segments are Class 1
ND	1	15	0	0	N/A	0 of 2 HSS Segments are Class 1
	2	17	0	0	N/A	0 of 2 HSS Segments are Class 1
NI	1	168	110	0	7	4 of 12 HSS Segments are Class 1
	2	164	111	0	7	4 of 12 HSS Segments are Class 1
NV	1	11	184	0	89	12 of 71 HSS Segments are Class 1
	2	9	183	0	89	12 of 67 HSS Segments are Class 1
Total	1	486	490	5	52	46 of 122 HSS Segments are Class 1
	2	466	488	5	50	46 of 117 HSS Segments are Class 1

* Note: Along with the RI-ISI Program implementation application, Duke Energy Corporation submitted a relief request, Serial Number 01-008. The request seeks relief from performing volumetric examination of socket welds on selected high safety significant segments as defined by WCAP-14572. As an alternative, Duke proposed to perform a visual (VT-2) examination.

It is recognized that most failure mechanisms at work within a given segment are uniform throughout the segment. Therefore, rather than choose a particular weld upon which to concentrate a single socket weld inspection, Duke has conservatively chosen to perform a VT-2 on all socket welds within the entire segment each refueling cycle. This explains why the Class 1 system, HSS socket weld inspection percentages are high.

12. REQUEST:

Page 83 of the Topical states that for a WOG plant application, "(SRRA) tools were used to estimate the failure probabilities for the piping segment". Page 6 and 7 of the related safety evaluation also state that the failure probability estimate, "is subsequently used to represent the failure probability of the weld." Section 3.4 of the submittal states that the team used, "the risk assessment (SRRA) software program (...) to aid in the process." Please confirm that, where the SRRA code was applicable, the appropriate failure frequencies estimated by the SRRA code (that is all the significant degradation mechanism and the worst operating characteristics within the segment applied at one location) were used in the subsequent risk ranking and change in risk calculations. If, instead, the failure frequencies used in the risk ranking or the change in risk calculations were selected from a range of values (or otherwise modified) by the expert panel or other analysts, please provide a description of this process and explain how your method comports with the approved Topical and the SE.

RESPONSE:

Where the SRRA code was applicable, the appropriate failure frequencies estimated by the SRRA code were used in the subsequent risk ranking and change in risk calculations.

13. REQUEST:

Section 3.8 of the submittal discusses a number of segments where the Perdue model was not applied and refers to Section 3.7.3 in the WCAP. WCAP Section 3.7.3 Selection of Actual Inspection Locations starts once the number of locations for inspection has been determined. Application of the methodology for determining the number of location to be inspected in 3.7.1 Structural Element Selection Matrix and 3.7.2 Sample Size Selection indicates that, if the single butt weld segments in Region 1 have a weld that is exposed to a degradation mechanism (Region 1A), the weld should be inspected. If the single butt weld is not exposed to a degradation mechanism, the default of 1 inspection for the segment or segment parts in Region 1B would indicate that the weld should be inspected. In the 12 segments that had only one butt weld in Unit 1 and the 18 segments that had only one butt weld in Unit 2, how many of these welds are to be inspected. If all welds are not being inspected,

a) please describe how the number of inspections was determined and justify this deviation from the WCAP methodology, and

b) how many of these segments' welds were being inspected in the Section XI program versus the RI-ISI program and how is the change in risk estimated for each segment?

RESPONSE:

All twelve (12) Unit 1 and eighteen (18) Unit 2 high safety significant (HSS) segments having a single butt weld are scheduled to have the butt welds inspected.

14. REQUEST:

The submittal states that the PRA dated December 1997 was used to evaluate the consequence of pipe ruptures. The submittal further states that "plant changes are reviewed to ensure that the PRA model and supporting documentation accurately reflect the current configuration and operational practices consistent with its intended application." Please confirm that this review was performed as part of the development of the RI-ISI submittal and that documentation of this review is retained as a program record.

RESPONSE:

Plant changes are reviewed to ensure that the PRA model and supporting documentation accurately reflect the current plant configuration and operational practices consistent with its intended application. This review is performed as part of an ongoing PRA update process and is not expressly conducted for the RI-ISI program alone. The guidance for this activity is contained in our administrative procedures. Per these procedures, records of these reviews and their impact to the PRA model are maintained as supporting documentation for model updates. During the timeframe from December 1997 until January 2000 (when the McGuire RI-ISI program was initiated), there were no changes identified which would have an adverse impact on the PRA.

15. REQUEST:

The submittal states that a peer review was performed by the Westinghouse Owners Group (WOG) Risk-Based Technology Working Group. Please identify the relationship between a review by this group and a WOG PRA peer review certification team. Please confirm that the results of the working group's review were reviewed to ensure that none of the changes or issues raised are expected to influence the results used to support the RI-ISI submittal. Please confirm that the documentation of this review is retained as a program record.

RESPONSE:

The peer review performed by the WOG Risk-Based Technology Working Group and the WOG PRA peer review certification team are one and the same. The WOG peer review team provided a number of observations and areas for improvement in the McGuire PRA. These observations ranged from identifying areas where the supporting documentation was missing to questions on the scope and completeness of the modeling. Some of the specific observations are related to revision 3 of the PRA, which was in progress at the time of the review, and are not relevant to the revision 2 model used in the RI-ISI program development. Resolving any one of these issues could result in a change in the CDF estimate, either up or down. The magnitude of the change in CDF is expected to be moderate and while the details of the risk calculations would change, these changes should not be of such a magnitude to significantly affect the overall ranking of the segments. Based upon a review of the observations provided by the peer review team, changes to the estimates for CDF and LERF are not expected to negatively impact the applicability of the MNS PRA to the RI-ISI project. The documentation of the review will be maintained as part of our RI-ISI documentation.

16. REQUEST:

Please provide the following with respect to the Staff Evaluation Report on the IPE submittal is dated June 30, 1994.

a) The SER stated that PRA upon which the IPE was based included external events. The submittal states that the CDF and LERF results provided exclude the contribution from seismic initiators. How were external events included in the evaluation to support the RI-ISI submittal?

b) The SER noted a weakness in the documentation of the Human Reliability Analysis that could complicate the subsequent updates of the PRA. Please provide any comments or observations from the (WOG) Risk-Based Technology Working Group regarding the adequacy of the HRA documentation. If there are any negative comments, please provide an explanation as to the influence of the difficulty of HRA updates might have on the results used to support the submittal.

RESPONSE:

(a) The main McGuire PRA plant fault tree contains all evaluated internal and external events except for the seismic initiator. The seismic fault tree is generated and solved separately from the main PRA fault tree because the seismic core damage frequency (CDF) is calculated using Monte Carlo techniques. The core damage sequences that dominate the seismic results are the station blackout sequences. From a plant response perspective, these sequences look very much like the sequences that result from tornadoes and LOOP initiated transients. The same systems are required to prevent core damage. These core damage sequences are characterized by the loss of all engineered safeguards systems as a result of the station blackout. As a result, the failure of individual components or piping segments in the mechanical systems has little or no influence on the results. The tornadoes and LOOPs rarely contributed significantly to the CDF/LERF calculations for the piping segments. Because the non-seismic external initiators are included in the analysis (e.g., tornado) and these have been seen to contribute little to the results, the exclusion of the seismic events greatly simplifies the analysis without a significant loss of accuracy in the final segment rankings.

(b) The SER on the McGuire IPE submittal did note weaknesses in the documentation but the NRC's "... audit did not identify any major problem with respect to the technical basis and level of analysis of the McGuire HRA." The HRA and the documentation of the process has been and will continue to be the subject of process improvement initiatives. The peer review team observed that the documentation of specific calculations for post imitator HEPs is "excellent" but did note some specific areas for improvement. These included comments on the identification of procedural steps and traceability to the supporting T/H analysis. No findings were made that the values for the human error probabilities were unreasonable. Evolution of the HRA documentation and the reconstitution, as needed, of the supporting T/H bases will continue. None of the peer review team comments negatively impact the analysis performed in support of the submittal.

17. REQUEST:

Will the RI-ISI program be updated every 10 years and submitted to the NRC consistent with the current ASME XI requirements?

RESPONSE:

The RI-ISI program will be updated every 10 years and the resulting RI-ISI elements subject to inspection will be included in the 10 year inspection plan that is submitted to the NRC according to ASME Section XI requirements.

18. REQUEST:

Under what conditions will the RI-ISI program be resubmitted to the NRC before the end of any 10-year interval?

RESPONSE:

The RI-ISI program will be resubmitted to the NRC before the end of any 10-year interval if any of the following occur:

- the RI-ISI methodology applied changes
- the scope of the application changes
- there is an impact to the basis for NRC approval in the plant specific Safety Evaluation.

19. REQUEST:

Page 8 of your submittal "Additional Examinations" presents the criteria for additional examinations if unacceptable flaws or relevant conditions are found during examinations.

a) Please clarify the term "initial number of elements required to be inspected". Does this refer to inspections planned for the current outage or for the current interval?

b) Please verify that the elements selected for additional examination based on the root cause or damage mechanism will include high risk significant as well as medium risk significant elements (if needed) to reach the required number of additional elements.

RESPONSE:

a) The phrase "initial number of elements required to be inspected" refers to the current outage.

b) Elements selected for additional examination based on a root cause or damage mechanism will include high risk significant as well as medium risk significant elements (if needed) to reach the required number of additional elements. Medium in this context is understood to mean the numerical risk ranking of the element as provided to the expert panel, since the final risk ranking after the expert panel phase is either high or low only.