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Vogtle Electric Generating Plant
Response to Request for Additional Information Regarding
Risk Informed Inservice Inspection Program Submittal

Ladies and Gentlemen:

On July 26, 2002, Southern Nuclear Operating Company (SNC) submitted a request, in accordance with 10 CFR 50.55a(a)(3)(i), to use a Risk-Informed Inservice Inspection (RI-ISI) Program as an alternative to the Vogtle Electric Generating Plant (VEGP) Units 1 and 2 ISI Program requirements for ASME Code Category B-F, B-J, C-F-1, and C-F-2 piping only. The proposed alternative was based on the risk-informed process described in Westinghouse Owners Group (WOG) WCAP-14572, Revision 1-NP-A, "Westinghouse Owners Group Application of Risk-Informed Methods to Piping Inservice Inspection Topical Report," and WCAP-14572, Revision 1-NP-A, Supplement 1, "Westinghouse Structural Reliability and Risk Assessment (SRRA) Model for Piping Risk-Informed Inservice Inspection." Turkey Point 3, Surry 1 & 2, Millstone 2 & 3, North Anna 1 & 2, McGuire 1 & 2, Sequoyah 1 & 2, and Watts Bar 1 have all received approval to use the proposed alternative based on the risk-informed process described in WCAP-14572.

On February 4, 2003, SNC received a Request for Additional Information (RAI) containing 17 questions from the staff concerning the VEGP RI-ISI Program Submittal. After a SNC and Westinghouse review of the RAI, a March 20, 2003, conference call between the staff, staff consultants, Westinghouse, and SNC was conducted regarding clarification of Questions 4 and 12. Question 12 is related to uncertainty analysis and has been withdrawn by the staff as a result of the conference call discussion. Question 4 is related to the failure probability determination for piping segments with multiple pipe sizes and is discussed in the enclosed response to the 16 remaining RAI questions.

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It is the SNC and Westinghouse position that the intent of the NRC approved WOG WCAP-14572 was met in the July 26, 2002, SNC submittal. Additionally, SNC's response to the 16 remaining RAI questions should reinforce this position. Therefore, SNC requests that approval be given by June 30, 2003, to implement the RI-ISI Program at VEGP as submitted on July 26, 2002, in order to support the September 2003 VEGP Unit 1 refueling outage.

This letter contains no NRC commitments. If you have any questions, please advise.

Sincerely,

Jeffrey T. Gasser

JTG/DRG

Enclosure:

cc: Southern Nuclear Operating Company
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Mr. G. R. Frederick, General Manager – Plant Vogtle
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U. S. Nuclear Regulatory Commission
Mr. L. A. Reyes, Regional Administrator
Mr. F. Rinaldi, NRR Project Manager – Vogtle
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Enclosure

Vogtle Electric Generating Plant
Response to Request for Additional Information Regarding
Risk Informed Inservice Inspection Program Submittal

1. <u>NRC Request</u>

On page 1 of your submittal, you state that the plant VEGP-Specific Level 1 and Level 2 Probabilistic Risk Assessment (PRA) Model, Revision 2C, was used for your RI-ISI analysis. Please provide the date of this PRA model.

<u>SNC Response</u>

Revision 2c of the Vogtle PRA fault tree model is dated 08-28-2001.

2. <u>NRC Request</u>

2a. State which version of your PRA has been peer reviewed by the Westinghouse Owner's Group (WOG) peer review process.

<u>SNC Response</u>

Revision 2c of the Vogtle PRA fault tree model was reviewed.

2b. On page 2 of your submittal, you state that eight PRA elements were judged by the peer review to have findings that are considered "Contingency Grade 3". Will any of these items adversely affect your RI-ISI analysis?

<u>SNC Response</u>

The peer review process assigns grades of 1 through 4 after assessing the technical merits and capabilities of 11 main technical elements. Each technical element is graded, with Facts and Observations (F&Os) developed to support the grading. F&Os are then broken into four levels of significance (A, B, C, or D), as follows:

• Significance Level "A" – Extremely important and necessary to address to ensure the technical adequacy of the PRA.

• Significance Level "B" – Important and necessary to address, but may be deferred until the next PRA update.

• Significance Level "C" – Recommended and considered desirable, but not likely to significantly affect results or conclusions.

- Significance Level "D" – Editorial or minor technical.

During the Vogtle peer review, the Vogtle PRA was assigned a Grade 3 for three of the main technical elements and a "Contingency Grade 3" for eight of the elements. A Grade 3 indicates that the PRA is adequate to support regulatory applications when combined with deterministic insights. The "Contingency Grade 3" elements will become Grade 3, when the recommended F&O enhancements are addressed. There were no Significance Level "A" F&Os; however, there were 13 Significance Level "B" F&Os, associated with the eight Contingency Grade 3" elements. Level "C" or "D" F&Os, by definition, would not significantly affect the results or conclusion and were not addressed in this response.

The 13 Significance Level "B" F&Os were evaluated as described below, and it was determined that their deferral to the next PRA update will not adversely affect the use of the current PRA model for the RI-ISI analysis, when supplemented by deterministic insights.

(1) Observation IE-06: *Evaluation of CCF probability between normally running and normally standby Nuclear Service Water pumps.*

The VEGP Nuclear Service Cooling Water (NSCW) system has two trains, and each train consists of three pumps. Originally, two pumps on each train were used as primary pumps and one pump on each train was used as a standby pump. Until recently, the primary pumps operated most of the time; however, the primary pumps and the standby pumps are now rotated to reduce pump start failure due to moisture. With this operating history, the accumulated hours on the standby pumps are significantly smaller than the operating hours on the primary pumps, and common cause failure (to run) due to simultaneous wear-related failure of all pumps is not credible. However, if the pump suctions are blocked by debris, then all the pumps could be affected. In the VEGP PRA model, it is assumed that if the normally running primary pumps fail due to common cause failure from suction-related problems such as debris, the standby pump will also fail (to run). However, it is assumed that CCF of the primary pumps due to simultaneous wear-related failures will not fail the standby pump.

The INEEL CCF event data base was used to calculate the fraction of a specific cause contributing to CCF failure of all NSCW pumps. The fraction was calculated as:

(number of CCF events caused by debris) / (total number of CCF events).

The WOG peer review comments were:

- The manner in which this fraction is calculated may be non-conservative because all CCF events were assumed to contribute equally to pump CCFs.
- The current assumptions about CCF between primary and standby pumps may be conservative

In fact, the manner in which the fraction was calculated yielded conservative results. The rationale for this conclusion is as follows. According to industry experience, almost all CCF events due to debris clogging have occurred in systems where the pumps take suction from either a river or lake. However, the VEGP NSCW system, which functions as the ultimate heat sink, is isolated from any river or lake environment. The VEGP NSCW system has large cylindrical concrete basin-type cooling towers (one per train) from which the NSCW pumps take suction. Furthermore, makeup water for the cooling tower basin is provided from screened aquifer-based well water. Thus, at VEGP, it is very unlikely that the NSCW system would be exposed to debris-related CCF events. Therefore, treating debris-related CCF events in the same way as other CCF events in calculating the fraction yielded conservative results.

The VEGP NSCW pump CCF model represents a more realistic approach than either including all of the pumps in the same CCF group or separating the standby pumps completely from the CCF group of the primary pumps.

In summary, the VEGP NSCW pump CCF model is either realistic or somewhat conservative. This is not expected to adversely affect RI-ISI conclusions. This conclusion can be further bolstered by the fact that the uncertainty analysis performed on the PRA results assumed a very broad distribution.

(2) Observation AS-05: *ISLOCA and mitigating system.* Observation AS-05 states two issues:

(a) The uncertainty correlation is not properly stated in evaluating ISLOCA frequencies.

This is not expected to adversely impact RI-ISI conclusions because even though an uncertainty analysis was not performed in evaluating the ISLOCA frequency, uncertainties on the PRA results were considered when they are applied to VEGP RI-ISI evaluations.

(b) The impact of ISLOCA on the mitigating system (High pressure safety injection system) is not properly addressed in calculating CDF and LERF.

In the VEGP PRA, mitigation of ISLOCAs by the high pressure injection (HPI) system was credited. The VEGP HPI system includes two charging pump trains and two Safety Injection (SI) pump trains. If an ISLOCA occurs in one portion of the HPI piping, mitigation by HPI may not be possible. In the VEGP PRA, the following six ISLOCA paths were identified and quantified:

ISLOCA Path	ISLOCA Frequency
Seal Water Return Line	8.43E-09
Reactor Coolant Pump Thermal Barrier HX	8.41E-07
Lines to Charging Pump Discharge Header	9.37E-07
Safety Injection Pump Discharge Lines	1.40E-07
RHR Discharge Lines	2.30E-06
RHR Suction Lines	1.15E-06
Total	5.38E-06

Among the above six ISLOCA paths, two ISLOCA paths could impact the HPI system. HPI (via charging pumps) will be impacted by ISLOCA in 'Lines to Charging Pump Discharge Header' and HPI (via SI pumps) will be impacted by ISLOCA in 'Safety Injection Pump Discharge Lines.' The current VEGP PRA model does not adequately address this impact.

In order to investigate the significance of this modeling inadequacy on the RI-ISI conclusions, ISLOCA frequency calculations were further reviewed. The current VEGP ISLOCA frequency is based on calculations that were performed during the VEGP IPE.

ISLOCA through 'Lines to Charging Pump Discharge Header' is initiated by failure of check valves to re-close in the normal charging lines or in the Reactor Coolant Pump (RCP) seal injection lines, when a running charging pump is stopped and the stopped-pump discharge check valve also fails to close. The CVCS design reflected in the IPE had a normal charging pump, which was a positive displacement pump (PDP), and two centrifugal charging pumps. In the IPE, it was assumed that one of the centrifugal charging pumps was running while the normal charging PDP was in standby.

Changes in the VEGP CVCS design and operation have been made since the time of the IPE which replaced the normal charging PDP with a centrifugal pump. Currently, the normal charging pump is in operation most of the time. According to VEGP procedure 13006-1, during power operation, there is no time duration when all charging pumps are stopped, even temporarily. When switching from the normal charging pump to a charging pump, or vise versa, is performed, the previously running pump is not stopped until a standby pump is started and its flow is verified. Thus, for the current VEGP design and procedures, it is conservative to consider the failure to close of the charging line and seal injection line check valves when a charging pump is stopped during power operation.

Furthermore, the failure of RCP seal injection line check valves would not cause an ISLOCA through lines to the charging pump discharge header, unless the RCP seals have significant leakage. Thus, the ISLOCA frequency through the RCP seal injection lines should be multiplied with the probability of a significant RCP seal leak. Since the frequency of an ISLOCA through RCP seal injection lines, in the current VEGP PRA model was not multiplied with the RCP seal failure probability, the current ISLOCA frequency through the charging pump discharge header is very conservative.

In addition, an ISLOCA through normal charging and RCP seal injection lines can be isolated. An ISLOCA through normal charging line can be isolated by closing one of the following valves: MOV HV8105, MOV HV8106, AOV HV182, or AOV FV121. The normal charging path is also automatically isolated by a safety injection signal. An ISLOCA through RCP seal injection line can be isolated by closing a MOV HV8103A (B, C, and D). Once the affected line is isolated, the ISLOCA ceases to exist. This isolation capability was not credited in the current VEGP ISLOCA calculations.

As a result, the frequency in the current VEGP PRA for ISLOCA through lines to the charging pump discharge header is conservative.

Similarly, the ISLOCA through safety injection pump discharge lines (cold leg injection lines) can be isolated by closing MOV HV8835 or by closing MOV HV8821A and HV8821B. An ISLOCA through the hot leg injection lines was screened out because its frequency was expected to be much less than the ISLOCA frequency through the cold leg injection lines. A hot leg injection path has a normally closed MOV, while cold leg injection paths have normally open

MOVs. The capability to isolate was not credited in the current VEGP ISLOCA calculations. Therefore, the frequency for ISLOCA though the safety injection pump discharge lines is also conservative.

Further, the HPI system will not be completely disabled in either of the two ISLOCA cases. The SI pumps will still be available for ISLOCA through charging pump discharge lines, and the charging pumps will still be available for ISLOCA through SI pump discharge lines.

In conclusion, the non-conservatism of not addressing ISLOCA impacts on mitigating systems is largely canceled out by the conservatisms found in the calculation of the ISLOCA frequency through the charging pump and SI pump discharge header. Thus, the impact of not revising the model to account for this WOG peer review finding is not expected to significantly affect the RI-ISI conclusions.

(3) Observation AS-08: *Re-examine the Binning of SGTR sequences (SGTR-7, SGTR-9, SGTR-10) for LERF.*

SGTR-7: SGTR*(RX trip success)*(AFW success)*
(HPI failure)*(secondary depressurization for LPI failure)
SGTR-9: SGTR*(Rx trip success)*(AFW failure)
(HPI for Feed and Bleed (F&B) success)*(PORVs for F&B success)*(HP recirculation for long term F&B failure)
SGTR-10: SGTR*(Rx trip success)*(AFW failure)*
(HPI for F&B success)*(PORVs for F&B failure)

SGTR-7 is a containment bypass LERF sequence. SGTR-9 and SGTR-10 are non-containment bypass LERF sequences (containment isolation should also fail to be a LERF). (SGTR refers to a Steam Generator Tube Rupture.)

The binning of SGTR-7 into 'containment bypass' is either realistic or slightly conservative because no credit was given to containment isolation. The binning of SGTR-9 into 'non-bypass' is also realistic because in SGTR-9, the leakage path into containment is open for feed-and-bleed operation.

Binning SGTR-10 into 'non-bypass' may be or may not be conservative. In order to investigate the accident progression in SGTR-10, a MAAP run was made. For a double-ended break of a single Steam Generator

(SG) tube, i.e. break size equals 2 x (cross sectional area of a tube), MAAP results showed that core damage will not occur within 24 hours because HPI water leaking into the ruptured SG can provide enough decay heat removal when it steams out of the secondary safety valves. Even though radioactivity is released outside containment, a 'large' release will not occur unless core damage occurs. Furthermore, according to the WOG definition of LERF, if core damage occurs after four hours into the SGTR initiating event, it is not considered as an 'Early' release. Thus, SGTR-10, for a double ended break of a single tube, is not an LERF sequence and including this sequence in the LERF model would lead to conservative results.

Since a SGTR was defined in the VEGP PRA as a small leak (which has a leak rate larger than the capacity of a charging pump) up to a full double ended break of a single SG tube, another MAAP run was made for SGTR-10 with smaller break size - a size as big as 1x (cross section area of a single tube). The results for this case showed that the break flow can not provide enough decay heat removal and core damage would occur at about four hours into the event from the SGTR initiation. However, the core damage will be delayed considerably if operators trip the RCP. According to the WOG definition for this case, SGTR-10 is marginally a LERF sequence.

As a result, depending on the size of the break in SGTR spectrum, SGTR-10 can be considered either a LERF or non-LERF sequence. Defining it as a LERF sequence in the VEGP PRA model is believed to be a slightly conservative assumption.

The binning of SGTR-7, SGTR-9, and SGTR-10 may not be a realistic assumption, but since it is biased in a conservative manner, the RI-ISI conclusions are not expected to be adversely affected by not revising the model to account for this WOG peer review finding.

(4) Observation DA-02: *CCF MGL factors, especially the beta factor for a RHR pump failure to start, are much lower than general industry values.*

A plant-specific CCF analysis for the VEGP RHR pumps was performed. As explained in SNC response to NRC Request #3-1, plant-specific CCF values could be much lower than generic values. For example, the INEEL CCF database documented 19 PWR RHR pump fail-to-run CCF events. Sixteen out of those 19 events have occurred during mid-loop operation. Mid-loop operation occurs only during shutdown, thus these 16 of 19 events are not applicable to an At-Power PRA. Generic CCF values generally do not screen-out any of these

events. This can result in a significant overestimation of RHR pump CCF failure probabilities in an At-Power PRA model. Thus, it is inappropriate to assume that a CCF value is incorrect solely because the plant-specific value is lower than a generic value. Instead, use of plant-specific CCF failure probabilities to realistically represent plant conditions should be preferred over the use of generic values.

Recently, a more thorough plant-specific CCF analysis, based on the new CCF Database (INEEL CCF Database), has been completed for the VEGP RHR pumps. A Bayesian update technique was used in calculating the CCF parameters. The following results show that newly estimated CCF values are different from the old values.

Failure Mode	Old Probability	New Probability
Fail-to-Start	1.25E-5	1.02E-4
Fail-to-Run	1.22E-6	7.55E-7

Another finding related to VEGP RHR pump modeling coming from the WOG peer review (Observation QU-6) was that RHR pump demand failure should be included in the low pressure recirculation (LPR) fault tree for the small LOCA case. The VEGP PRA model was revised to account for the addition of the RHR pump demand failure to the LPR failure for small LOCAs and using the new RHR pump CCF probabilities. Using this revised model, the baseline total CDF and the RHR segments were re-evaluated. Based on the results of the re-evaluation, the baseline CDF increased by approximately seven percent. Although the conditional CDF for each RHR PRA run increased, the safety significance, as measured by risk reduction worth, (RRW) did not change for any of the RHR pipe segments evaluated.

(5) Observation DA-05: *Probability of Relief valve failure to re-close under two phase flow condition in ATWS*

During the initial phase of an ATWS, two-phase flow may pass through relief valves. Relief valves under a two-phase flow condition could have a higher probability of failure to re-close than those under a single phase (steam) flow condition. The VEGP PRA model uses the same probability for both flow conditions, which may be a non-conservative assumption. However, the impact of this assumption is not expected to adversely impact the RI-ISI conclusions, because ATWS contributes less than 0.01% of the total CDF and less than 0.1 % of the total LERF.

Furthermore, none of the pipe segment failures considered in the VEGP RI-ISI evaluations cause an ATWS initiating event or affect the relief

valves. Therefore, the impact of changes in initiating event frequencies or in mitigating system probabilities (resulting from changes in the relief valve failure probability) on consequence CDF/LERF calculation results would be inconsequential.

(6) Observation HR-02: *No specific references for Timing for HRA.*

Generally, two types of timing information are needed for performing a HRA. The first one is the *available time window*. The action under consideration must be performed within the *available time window* in order to prevent an undesirable event such as core damage. The *available time window* is estimated based on information from realistic transient and thermal-hydraulic analyses. The second type of timing information needed is the *operator response time*, which is the time operators need to perform task(s) to prevent the undesirable event. The *operator response time* can be estimated based on information gathered from simulator experiments and operator interviews. If the *available time window* is less than the *operator response time*, no operator action is credited.

The WOG peer review finding recommended the addition of a reference, or basis, for the time window to each operator action.

The *available time windows* in the VEGP PRA model are based on generic timing information provided by Westinghouse. Thermal hydraulic analysis, such as MAAP analysis, could be used for determining more plant-specific *available time windows*, but it is expected that VEGP-specific timing information would be comparable to generic values.

Regarding the second necessary timing information, interviews with groups of Senior Reactor Operators and Operators provided the basis for a realistic assessment of the various *operator response times*.

Any deviation of plant-specific timing information from generic timing information is not expected to impact the RI-ISI conclusions adversely. This expectation is held because the VEGP HRA methods (SLIM for procedure-based actions and THERP for recovery actions) are not time-sensitive enough to produce significantly different operator error probabilities for small differences in timing information.

(7) Observation HR-05: *Use of a high screening value for Operator error in cross-tying opposite unit DGs.*

In the VEGP PRA model, failure to cross-tie the opposite unit's Diesel Generators (DG) is represented by a basic event, 'operator fails to cross-tie the opposite unit diesel.' Since failure to cross-tie is dominated by human error, a relatively high screening value of 0.2 was assigned for this event based on engineering judgment.

The WOG peer review finding recommended that a detailed HRA be performed to estimate a realistic operator error probability and that the contribution of the opposite unit's DG hardware failure probability be included.

Since the current modeling is considered to be conservative, the impact of not revising the model to account for the WOG peer review finding is not expected to affect the RI-ISI conclusions adversely.

(8) Observation DE-01: *Need of re-examining internal flooding analysis to determine the need to re-evaluate any screening.*

The VEGP PRA internal flooding analysis was based on plant walk downs and design review, and most of the internal flooding candidates were screened out due to their low probability. However, for RI-ISI, internal flooding impacts from pipe breaks were analyzed as part of the VEGP RI-ISI indirect effects analysis. Thus, this WOG PEER review finding does not apply for the RI-ISI evaluation and the RI-ISI conclusions are not adversely affected.

(9) Observation QU-01: *No formal search for and evaluations of the impact of unique or unusual sources of uncertainty. No sensitivity analysis to identify and address the effect of key LERF issues*

The VEGP PRA calculates point estimates of conditional core damage probabilities/frequencies (CCDP/CCDF). However, as part of the RI-ISI importance calculations, probability distributions (lognormal distributions) were assigned on CCDP/CCDF (and CLERP/CLERF). When the uncertainty analysis was performed, point estimate values were equated to the median of lognormal distributions, and error factors (5, 10, or 20) were used to define the spread of the distribution. (Please refer to WCAP-14572, revision 1-NP-A, pages 125-129).

The circumstance described by this WOG PEER review finding is not expected to adversely affect the conclusions of Vogtle RI-ISI because an uncertainty analysis was performed as part of the Vogtle RI-ISI calculations.

(10) Observation QU-02: *"Station blackout sequences, SBO-17,23,31, and 38 involve failure to restore offsite power before one hour and a subsequent failure to restore power by some later time. The later time for recovery ranges from 6 hours to 16 hours. The same probability of 0.1 is used for all of these sequences (probability of event: OA-OSPR-----H). This is inappropriate since the probability of power recovery at subsequent times in not constant in this time frame."*

This comment reflects a misunderstanding of event OA-OSPR-----H. OA-OSPR-----H is not the probability of offsite power recovery within X hours, but it is an operator error probability for failure to restore AC power from the reserve auxiliary transformers. A conservative value of 0.1 was assumed for this operator action for all SBO sequences. However, this conservatism is not expected to affect the RI-ISI conclusions adversely.

In fact, the VEGP PRA model uses different offsite power (LOSP) non-recovery probabilities in different time frames. For example, the non-recovery probabilities of LOSP in different time frames are as follows:

within 1 hour:	0.272(event 1HR-1)
within 6 hours:	0.235(event XHR-61)
within 8 hours:	0.178(event XHR-81)
within 13 hours:	0.0899(event XHR-131)
within 16 hours:	0.0559(event XHR-161)

These LOSP non-recovery probabilities are applied to the specific minimal cutsets during the recovery analysis.

(11) Observation QU-03: *DG mission time*

The expected mission time for DGs used in the VEGP PRA model is based on calculations which provide consideration for the probability of offsite power recovery. DGs are required to run only until offsite power is recovered. Since DGs are required to run only after a loss of offsite (LOSP) event, changes in DG mission time will have the greatest impact on LOSP-induced CDF and LERF.

However, since none of the pipe segment failures considered in the Vogtle RI-ISI cause either a LOSP or affect the DGs, the impact of changes in initiating event frequencies or in mitigating system probabilities on CDF calculation results (resulting from changes in the DG mission time) would be inconsequential.

Thus, the circumstance described by this WOG PEER review finding will not adversely impact RI-ISI conclusions.

(12) Observation QU-05: *No comparison of results with other similar plants*

Even though the VEGP PRA results have not been explicitly compared with other similar plants' results, VEGP PRA models and results have been extensively reviewed during the different stages of their development. The IPE was performed by Westinghouse, and an independent review was performed by an in-house group consisting of corporate and plant personnel. Representatives of Pickard, Lowe and Garrick, Inc., participated as an independent consultant and performed detailed reviews of all aspects of the IPE. The IPE was then reviewed by the NRC and a favorable safety evaluation report was issued. Later, the IPE was converted from a large event tree/small fault tree methodology to a small event tree/large fault tree methodology by Science Applications, Inc. The converted model and its subsequent revisions have been reviewed by the in-house PRA group. An additional major review was performed by the WOG Peer Review Group. Further, a quality check based on the NEI PSA Application Guide was also performed.

Thus, given the developmental history of VEGP PRA, the lack of a systematic comparison of VEGP PRA results with other similar plants' results is not expected to adversely affect the RI-ISI conclusions.

(13) Observation QU-06: *'RHR pump fails to start' is missing in Low Pressure Recirculation tree for small LOCA sequences.*

The impact of this finding was estimated concurrent with the impact of Observation DA-02 because they are related. (See Observation DA-02 above.)

2c. You state in your submittal that, "This deferral [to resolve Contingency Grade 3 items] does not adversely affect the use of the current Revision 2C of the PRA model for applications such as the RI-ISI when supplemented by deterministic evaluations." What "deterministic evaluations" are supplemented with the use of the Revision 2C PRA model for use in the RI-ISI analysis?

SNC Response

As in any risk-informed application, use of risk insights in decision making is considered an adjunct to deterministic design basis criteria. In addition, to account for the lack of a robust treatment of every modeling or plant-specific issue, an uncertainty analysis was performed on the PRA results assuming a very broad distribution approaching error factors of 5, 10, and 20. Finally, inputs from the Expert Panel were the ultimate judge of determining the risk significance of pipe segments. Consistent with the recommendations of Regulatory Guide 1.174, section 2.2.3.2, this is an acceptable approach to account for the level of detail in a PRA required to support a risk-informed application

3. NRC Request

3a. The NRC staff evaluation report (SER) on your Individual Plant Examination (IPE), dated April 15, 1996, stated that the licensee's approach to common cause failures (CCFs) only allowed those CCFs to remain in the database after an elimination process based on the judgment of an "expert" panel and doesn't consider those CCFs that have not yet occurred or have not been identified. The SER stated that the staff considered the licensee's CCF analysis to be limited due to the licensee's approach. What were the observations made by the WOG peer review of your CCF analysis? Please identify any improvements made to your CCF models and discuss why your current models are sufficient to support the RI-ISI submittal.

SNC Response

The VEGP CCF analysis was based on the NUREG/CR-4780 methodology. The NUREG/CR-4780 methodology had been the generally accepted CCF analysis methodology until publication of NUREG/CR-5485 in 1988. NUREG/CR-5485 is considered to be an enhanced version of NUREG/CR-4780.

According to the NUREG/CR-4780 (and also NUREG/CR-5485), historical CCF events are specialized for a plant-specific CCF. VEGP performed a plant-specific CCF analysis. In a plant-specific CCF analysis, each historic CCF event is reviewed and its applicability to the plant-specific features is determined. Different designs, environments, and operation modes are some of the factors affecting the applicability. A CCF event may be screened out, or applied with some probability, or applied with a probability of 1 according to the effectiveness of plant-specific defenses against the event.

It is a general observation that plant-specific CCF analyses may result in lower CCF values than generic values because generic values most likely include contributions from events that may not be applicable to plant-specific situations. Sometimes, a generic value could be an order of magnitude higher than a plant specific value. (Reference: Young G Jo. et al, "Effects of Operating Environments on the Common Cause Failures of Essential Service Water Pumps," Proceeding of International Topical Meeting on Probabilistic Safety Assessment, PSA02, October 2002, Detroit.)

Thus, elimination of non-applicable events from generic data when a plant-specific CCF analysis is performed is an accepted part of the CCF analysis methodology delineated in NUREG/CR-4780 and NUREG/CR-5485.

WOG peer review items related to CCF are also discussed in the SNC responses to NRC Request #2b.

3b. The SER also stated that the Human Reliability Analysis (HRA) analysis used a simplified THERP (Technique for Human Error Rate Prediction) which omitted failure modes associated with diagnosis. Also, human errors related to the calibration of equipment were not addressed in the HRA. What were the observations made by the WOG peer review on diagnosis and calibration errors of your HRA? Please identify any improvements made to your HRA and discuss why your current models are sufficient to support the RI-ISI submittal.

<u>SNC Response</u>

The VEGP PRA Model used THERP to evaluate human error probabilities (HEP) for recovery actions. It is incorrect to state that diagnosis errors were omitted in the VEGP HRA. In the VEGP PRA, a HEP was calculated as the sum of diagnosis error + error of execution. For example, the HEP," Isolate No.1 Seal Leak-off line" was calculated as:

Probability of diagnosis error (failure to respond to 1 of 1 alarm) + probability of execution (probability of error in using procedures with check off, short list <=10 items + probability of selecting the wrong control from a functionally grouped set).

For procedure-based actions, the Success Likelihood Index Method (SLIM) was used for calculating HEPs. In SLIM, groups of experts (2 SROs, 4 ROs, and an HRA analyst) determined Success Likelihood Indices (SLIs) of operator actions by examining seven performance shaping factors such as complexity of a task, timing, crew's level of knowledge, adequacy of guidance, man-machine interface, preceding/following actions, and stress level. A HEP was then calculated by converting SLI to probability based on the following relationship:

$$\log_{10}(1\text{-HEP}) = a*SLI + b$$

where a, b are constants determined using two anchor points, SLI values, and assigned HEPs.

CCF-type calibration errors were accounted in the CCF analysis. Thus, CCF events include contributions from CCF-type calibration errors.

WOG peer review items related to the HRA have already discussed in the SNC responses to NRC Request #2b.

4. <u>NRC Request</u>

4a. Are there any piping segments that include piping of different diameters?

<u>SNC Response</u>

Multiple piping diameters were included in some of the piping segments. Failure consequences were the primary factor utilized to initially divide systems into piping segments. This method led to some individual piping segments consisting of piping with a variety of pipe diameters. For example, a four inch diameter pipe with a two-inch diameter branch line may be part of the same piping segment if a failure at any portion of the segment would result in the same consequences. For multiple pipe size segments, sub-segments were defined by pipe size for the failure probability analysis.

4b. If so, how were the failure frequencies estimated for these segments? How does the methodology for determining the failure

frequency comport with the methodology described on page 71 of the Westinghouse Owners Group WCAP-14572, Revision 1-NP-A, "Westinghouse Owners Group Application of Risk-Informed Methods to Piping Inservice Inspection Topical Report," (WCAP-14572), dated February 1999?

Response - Failure probability estimates were generated for the piping segments using the Westinghouse Structural Reliability and Risk Assessment Model (Win-SRRA). Some of the input parameters used by the Win-SRRA code vary if the diameter of the pipe varies (e.g., nominal pipe size, thickness to outer diameter ratio). Failure probability estimates for segments made up of multiple pipe sizes were determined by performing multiple Win-SRRA cases. For the multiple pipe diameter cases, that resulted in multiple failure probability estimates, the highest failure probability associated with the segment was then used to represent the segment.

For each of these cases, the Win-SRRA code utilized 18 input parameters associated with the piping. For segments with multiple pipe sizes, some of the input parameters varied from case to case even though they represented the same segment. Different pipe diameters required different inputs for a number of the parameters. Other inputs also occasionally varied based on expert engineering judgment. SNC subject matter experts in ISI, NDE, materials, and pipe stress analysis (i.e., engineering panel) worked together to develop the input parameters for each Win-SRRA code case run. Therefore, each case represented a sub-segment and was evaluated for the expected conditions for the sub-segment.

In accordance with the WCAP methodology, the engineering panel developed limiting inputs for the evaluation of each segment or sub-segment. Input parameters may have varied for separate portions of the same segment for one of two reasons. One reason was that some segments contained multiple weld geometries (both butt and socket welds). In these segments, specific geometries were reviewed and different parameters were input to accurately model the geometry. The second reason was that, in a few cases, the input parameters for sub-segments varied slightly based on engineering judgment. For these cases, the inputs were developed by plant subject matter experts and were based on observed and recorded conditions. The basis for each judgment is documented in the Vogtle Win-SRRA engineering analyses. Though the input parameters for different cases of the same segment may vary, the parameters that were chosen for each case were the most limiting for that section of the piping segment. The limiting failure probability estimates associated with each pipe size for each segment are based on the realistic limiting inputs associated with that section of piping. For segments with multiple line sizes, multiple failure probabilities were

determined, and the most limiting (highest) failure probability associated with the segment was used to represent the segment.

As shown in Figure 3.5-1 and the accompanying text in the approved WCAP (WCAP-14572, Rev. 1-NP-A, Feb. 1999), failure probability estimation is the responsibility of the engineering team based upon their knowledge of the pertinent information at their plant and any potential concerns identified from industry experience at other plants. For example, PWRs have recently evaluated the increased potential for stress corrosion cracking at the reactor vessel outlet nozzle weld based upon the weld crack at the V. C. Summer plant. The SRRA tool is used to simply quantify the effects of the engineering team's input on the calculated leak and break probabilities. In fact, the second concern of the summary and conclusions (Section A.25 on page A-21) of the Nuclear Regulatory Commission (NRC) safety evaluation (SE) for the SRRA tool (Supplement 1 to the approved WCAP) endorses this position via the following:

> "The results of SRRA calculations should always be reviewed to ensure that they are reasonable and consistent with plant operating experience. Data from plant operation should be used to review and refine inputs to calculations."

Choosing the limiting SRRA probabilities from the sub-segments of different sizes in a segment is consistent with the NRC-approved methodology in the WCAP. The fifth item in the section of the NRC SE discussed above states:

> "The simplified nature of the SRRA code has resulted in a number of conservative assumptions and inputs being used in applications of the code. It is therefore recommended that sensitivity calculations be performed to ensure that excessive conservatism does not unrealistically impact the categorization and selection of piping locations to be inspected."

The methodology used to evaluate how degradation mechanisms in the different sized sub-segments are to be "combined" is consistent with the approved methodology as stated in the last paragraph of Section 3.2.3, *Piping Failure Potential*, of the NRC SER and in Section 3.2, *Simplified and Detailed Input* (page 16, paragraph 3), in Supplement 1 of the WCAP:

> "If more than one degradation mechanism is present in a given piping segment, then the limiting input values for each mechanism should be combined so that a limiting failure probability is calculated for risk ranking."

As discussed on page 84 in Section 3.5.6, Failure Probability Determination, of the approved WCAP, combining degradation mechanisms does not imply adding the failure probabilities for each mechanism. Typically, one

degradation mechanism will dominate the failure probability in the segment by several orders of magnitude. Multiple nominal pipe sizes in a single segment exist due to the establishment of initial segment boundaries based on consequence considerations as detailed on page 57 of the approved WCAP. An appropriate tool must be used to determine the failure impact of the potential degradation mechanisms to determine the dominant mechanism for the segment. As discussed above, the SRRA tool was used for the calculation of the failure probability estimates for Vogtle. As detailed in the supplement to the WCAP, multiple factors must be considered in determining the piping failure including:

1. degradation mechanisms,
2. construction examinations and practice,
3. preservice and inservice inspection history,
4. physical routing and configuration.

Table 3.5-1 of the WCAP and pages 1-1 and 1-2 of the WCAP supplement provide guidelines for items to consider when determining piping failure. In Section 3.5.4 of the WCAP, the estimated failure probability is identified as being dependent on and significantly influenced by the following four items: configuration, components, materials/chemistry, and loads.

A degradation mechanism's affect may vary based on the different physical configurations of the weld or welds. Socket welds have been identified as having low resistance to sustained vibration. It is also noted in Section 3.5.4 of the WCAP (Page 79) that interactions among the factors are common. A distinction is made in the discussion between component dependent failure modes, which are typically identified as localized within a segment, and material dependent or operational dependent mechanisms, which may be present throughout the entire segment. This distinction is consistent with Section 3.5 of the WCAP (page 71, paragraph 2), which states:

> "The failure probability of a segment is characterized by the failure potential (probability or frequency as appropriate) of the worst case situation in each segment (not a single selected weld in each segment)."

Consider the following two hypothetical examples based on typical scenarios and calculated probabilities experienced by plant engineering teams for SRRA input:

<u>Example 1</u>: Significant Differences In Pipe Sizes and Potential Degradation Mechanisms

In this example segment for high temperature and pressure piping, a 6-inch sub-segment extends some distance from a check valve to a tee, where the

flow is split into two three-inch sub-segments that each extend to a pump. Due to water hammer that has occurred in this same system at other plants, a one-inch sub-segment was added at the high-points (near each pump) of the 3-inch piping to periodically vent the system. If the check valve leaked, then the weld in the 6-inch sub-segment closest to the valve could experience thermal stratification. Although there is no evidence that the check valve is leaking in this specific example, it has occurred at similar plants so a high fatigue stress range and number of cycles for stratification is selected by the team for the simplified SRRA input. Because of the geometric layout of the piping, a weld in the 3-inch portion would see the highest water-hammer loading, which the team estimated had only a 1% chance of occurring due to the corrective actions that had already been implemented. Another weld in the same size piping also had a pre-service inspection indication that was small enough that a repair was not required per the American Society of Mechanical Engineers (ASME) Code. Because some imbalance of the pump was observed after the one-inch vent was installed, the potential effects of vibration in the three-inch pipe welds but especially in the one-inch pipe socket welds nearest to the pumps must be considered. All the piping in the segment is subject to fatigue loading due to normal heat-up and cool-down and periodic pump testing. The consequence of failure is a loss of inventory, and the system disabling leak rate has been conservatively assumed to be 2 GPM for all three pipe sizes in the segment.

The SRRA calculated large-leak probabilities after 40 years are as follows:

a) 3.3E-05 for the 6-inch pipe with thermal stratification,
b) 1.5E-05 for the 3-inch pipe with one-flaw, vibration (input corrected for size by SRRA Program) and a 1% chance of a severe water hammer,
c) 5.0E-04 for the 1-inch pipe with vibration (correction factor of 1),
d) 4.0E-02 for the 1-inch pipe with thermal stratification, one-flaw, vibration and a 1% chance of a severe water hammer.

The SRRA probability of 5.0E-04 should be selected by the engineering team for risk ranking because the probability of option d) is unduly conservative relative to plant and industry experience. The SRRA input for option d) would also be completely unrealistic relative to assuming the same 6-inch stratification loading near the check valve in the 1-inch line far away from the valve and the worst 3-inch water hammer loading in a 1-inch branch line.

<u>Example 2</u>: Small Differences In Pipe Sizes and Potential Degradation Mechanisms

In this example segment for moderate temperature and pressure, three different pipe sizes are also used (NPS of 1, 1.5, and 2 inches). All the piping in the segment is subject to fatigue loading due to normal heat-up and cool-down and relatively high seismic (SSE) loading for the design-limiting

event. The consequence of failure is loss of the system function, and the disabling leak rate has been conservatively assumed to be 10% of the flow through the largest of the three pipe sizes in the segment.

The SRRA calculated large-leak probabilities after 40 years for this example are as follows:

a) 8.9E-05 for the 2-inch pipe with its fatigue and SSE loading,
b) 1.2E-06 for the 1.5 inch pipe with its fatigue and SSE loading,
c) 7.5E-07 for the 1-inch pipe with its fatigue and SSE loading,
d) 9.1E-05 for the 2-inch pipe with the highest fatigue and highest SSE loading, independent of pipe size.

The SRRA probability of 9.1E-05 would be selected by the engineering team for risk ranking because the probability of option d) is not overly conservative relative to plant and industry experience, and the SRRA input would still be realistic relative to the uncertainties in the actual loading for the different pipe sizes (i.e., the difference between the SRRA calculated probability values of 8.9E-05 and 9.1E-05 is not statistically significant).

It is our position that assessing the unique input parameters based on the configuration, components, materials/chemistry, and loads by distinct quantification of all of the potential degradation with regard to localized and generalized degradation mechanisms in the entire segment is consistent with the NRC SE requirement stated below:

> "...ensure that excessive conservatism does not unrealistically impact the categorization and selection of piping locations to be inspected"

The consistency in the items used in determining the critical location or locations for inspection is supported by the requirement in WCAP Section 3.7.3. This section identifies that the selection of inspection location be based on the postulated failure mechanisms and the loading conditions for the piping segment considering the same four items as in the determination of piping failure, namely: configuration, components, materials/chemistry, and loads.

Furthermore, the inspection is not limited to a single degradation mechanism, but must consider all possible mechanisms contributing to the potential pipe failure for a given segment at the most likely location of occurrence.

It is therefore our conclusion that the process followed in sub-dividing the consequence defined segments in addressing the previously identified four items fully supports the directive to apply all possible degradation mechanisms at a single weld and ensure that there is no excessive conservatism in the piping categorization or selection of inspection location.

4c. For segments including piping of different diameters and where the Perdue method could be applied, how were the number of locations to be inspected determined? How does the methodology for determining the number for inspections comport with the methodology described on pages 170, 171, and 174 of the WCAP?

SNC Response

The Perdue Model is used to assist in the determination of the number of inspection locations for segments determined to be high safety significant by the plant RI-ISI expert panel. Segments were divided into sub-segments (or lots) for the Perdue Model evaluation using the following cases:

Case A: There is an identified active degradation mechanism and the segment is placed in Region 1 of WCAP-14572 Figure 3.7-1.

For this case, the piping in the segment is the same nominal diameter. One lot consists of the welds/locations susceptible to the degradation mechanism (Region 1A). Each susceptible location is included in the inspection program if it is not already part of an augmented inspection program. Welds/locations which are included in an augmented program remain in that program and are inspected in accordance with that program. The other lot consists of the rest of the welds in the segment (Region 1B). These are evaluated with the Perdue Model based on SRRA parameters which exclude the active degradation mechanism. The total number of inspections for the segment is the sum of the susceptible locations, plus the number of inspections required to achieve a 95% confidence level using the Perdue Model (a minimum of one location is specified even if the Perdue Model shows 100% confidence level with no ISI). This is consistent with the description of segments in Region 1 on page 168 of WCAP-14572.

Case B: There is no identified active degradation mechanism and the segment has been placed in Region 2 of WCAP-14572 Figure 3.7-1.

For this case, there are multiple pipe sizes in the segment. The Perdue Model inputs are specific to the pipe material and size. The first approach is to combine the most limiting inputs from each pipe size, use the total number of welds in the segment, and analyze the segment as one lot. Alternatively, if this analysis does not result in a 95% confidence level, then each pipe size is analyzed separately with the appropriate number of welds and the appropriate SRRA results. This divides the segment into lots according to pipe size. The confidence values of each lot are multiplied together to get the confidence level for the segment. The resulting confidence level must be greater than or equal to 95% for the Perdue Model evaluation to be acceptable. The total number of inspections for the segment is the number of inspections required to achieve a 95% confidence using the Perdue Model. A minimum of one location is specified, even if the Perdue

Model shows a 100% confidence level with no ISI. This is consistent with the description of segments in Region 2 on page 168 of WCAP-14572 and with the description of dividing a segment into multiple lots on pages 174 and 175.

Case C: There is an active degradation mechanism and the segment has been placed in Region 1 of WCAP-14572 Figure 3.7-1.

For this case, there are multiple pipe sizes in the segment. One lot consists of the welds/locations susceptible to the degradation mechanism (Region 1A). Each susceptible location is included in the inspection program if it is not already part of an augmented inspection program. Welds/locations which are included in an augmented program remain in that program and are inspected in accordance with that program. For the Perdue Model evaluation of the non-susceptible welds/locations (Region 1B), the steps followed are the same as in Case B above. The first approach is to combine the most limiting inputs from each pipe size after removing the active degradation mechanism, use the total number of welds minus the number of susceptible welds, and analyze the segment as one lot. If this is too conservative, then each pipe size is analyzed separately with the appropriate number of welds and the appropriate SRRA results. The confidence values of each lot are multiplied together to get the confidence level for the segment. The resulting confidence level must be greater than or equal to 95% for the Perdue Model evaluation to be acceptable. The total number of inspections for the segment is the sum of the susceptible locations, plus the number of inspections required to achieve a 95% confidence level using the Perdue Model (a minimum of one location is specified even if the Perdue Model shows 100% confidence level with no ISI). This is consistent with the description of segments in Region 1 on page 168 of WCAP-14572 and with the description of dividing a segment into multiple lots on pages 174 and 175.

Conclusion - Individual Perdue Model inputs are specific to the pipe material and size. Therefore, segments with multiple sizes must be evaluated in one of the three approaches discussed above. In all three approaches, the method for evaluating segments with the Perdue Model fully complies with the approved methodology in WCAP 14572.

As discussed above, SNC has followed the methodology contained in WCAP-14572. However, in recent WOG discussions with the NRC, questions have been raised regarding implementation of the approved methodology in WCAP 14572.

The first issue is with the calculation of the piping failure probability for segments with multiple pipe sizes. The NRC's interpretation is that for such segments, all degradation mechanisms found in the segment should be

applied to the analysis for each pipe size, with the highest resulting failure probability applied to the segment for ranking purposes. SNC has reviewed its proposed RI ISI program for all high safety significant segments. There is only one piping segment in each unit where the SNC implementation of the WCAP methodology and NRC interpretation would differ. This segment is the pressurizer surge line, a region 2 segment. The Vogtle surge line consists of two pipe sizes, 14 inches and 16 inches. In order to provide confidence that SNC will be able to detect any potential degradation in these segments, it has already been decided to select a weld from each pipe size for inspection. This was done as part of the weld selection process prior to the NRC's request for additional information. This additional weld was selected after the change in risk calculation was performed. No credit in the change in risk calculation for this additional inspection has been taken in the submittal provided to the NRC. Since one inspection will be performed on each pipe size, our position is that no additional inspections are required.

The second issue is that low safety significance segments that have multiple pipe sizes, different SRRA inputs (other than pipe size), and Section XI exams on the different pipe sizes may understate the safety level of the existing Section XI program, since only one inspection would be credited. This could make the change in risk criteria easier to meet with the new proposed RI ISI program. SNC has performed an additional change in risk evaluation to determine if this effect would be significant. Although the NRC has agreed that only segments with different SRRA inputs other than those associated with pipe size are in question, the piping failure contribution was modified for both the Section XI and Risk-Informed cases for all low safety significant segments with multiple pipe sizes. This simulates a segment for each pipe size ensuring that all Section XI inspections are credited. The Risk-Informed program, thus revised, still meets all change in risk requirements for Unit 1 and 2 with no additional inspections. Thus, the Vogtle analysis not only meets the criteria defined in the WCAP as implemented by SNC, it will also meet the criteria defined in the WCAP as interpreted by the NRC.

5. <u>NRC Request</u>

Tables 3.7-1 indicates that the expert panel moved some piping segments that have risk reduction worth (RRW) values greater than 1.005 from high safety significant (HSS) to low safety significant (LSS) based on their judgement. For example, in VEGP-1, Table 3.7-1 reports that the CV system has 10 segments with RRW greater than 1.005. The table also reports that, in the CV system, 2 segments with RRW less than 1.001 were selected for inspection. This indicates that the total number of HSS segments is expected to be 10 plus 2 or 12 segments.

However, the total number of HSS segments in the CV system is reported as 2. A similar example can be identified in Table 3.7-2 for VEGP-2.

The NRC staff recognizes that the Topical, WCAP-14572, Revision 1-NP-A, allows the expert panel to use deterministic information to place segments with RRW values greater than 1.005 in the LSS category, but page 143 of the Topical states that HSS "segments should not be classified lower by the expert panel without sufficient justification that is documented as part of the [RI-ISI] program. The expert panel should be focused primarily on adding piping to the higher classification." Justification for the reclassification of HSS segments to LSS should include a description of the specific characteristics that supports the expert panel's decision that the safety-significance of the segment is lower than the results of the quantitative evaluation and guidelines indicate. Sufficient detail is also needed such that the impact of future plant modifications on the characteristics selected by the expert panel when determining the safety-significance can be systematically evaluated to ensure continued applicability of the selected classification.

Based on the review of previous submittals, there are two types of results from the quantitative analysis that the expert panels have modified in order to reclassify segments from HSS to LSS. These results involve 1) human actions responding to the pipe failure and 2) material and operation characteristics of the segment. In order to expedite the review of the submittal, the type of information required to support a staff review of the response is provided below.

Reclassifying a HSS segment as LSS is often based on discarding a "without human action" RRW when that RRW is the only RRW that is greater than 1.005. This reclassification is based on a high degree of confidence by the expert panel that the likelihood that the operators fail to recover from an event is approximately zero. A basis for the decision would include a description of the information available to the operators to identify the failed functions, systems or component caused by the pipe failure: the procedures the operator would follow: the time available for the operator to recover: the time required by the operator to diagnoses and recover the failed functions: and the equipment available to recover from or mitigate the failures. Note that the ASME Standard for Probabilistic Risk Assessment for Nuclear Power Plant Applications only discusses proceduralized actions and non-proceduralized, skill-of-the-craft actions for use in PRA.

Reclassifying a HSS segment to a LSS segments is often based on discarding the pipe frequency estimate that is, in turn, based on material or operational characteristics input into the SRRA code. A basis for the decision should include an identification of those properties that resulted in the original HSS designation, the change in those properties that the expert panel determined more appropriately characterized the actual state of the SSCs, and a discussion why the characteristics the expert panel developed are expected to reduce the safety-significance of the segments from HSS to LSS.

Please clarify if the expert panel reclassified segments from HSS to LSS and, if so, identify which segments were reclassified from HSS to LSS. Please provide the justification documented as part of your RI-ISI program for each segment (or group of segments if the justification may be grouped) that was reclassified from HSS to LSS. For example, some documentation should be in the expert panel's meeting minutes. If the documented justification does not include the information discussed above, please provide the additional information.

<u>SNC Response</u>

There are ten segments that are "nominally" greater than 1.005 for each Vogtle unit that were designated as LSS by the expert panel. These small diameter segments are all CVCS system segments downstream of the charging pumps, except for a casing drain located on the pump. Of these ten segments, four segments on each unit have RRW values slightly less than 1.005 and were originally included because of computer generated "round-up." (Three of the four Unit 1 segments and two of the four Unit 2 segments are currently included in the RI-ISI program due to "delta-risk" considerations.)

Excluding the four segments that have RRW values less than 1.005, there are only six segments greater than 1.005 that were designated as LSS by the expert panel. (One of these six segments on Unit 1 is currently included in the program due to "delta-risk" considerations.) Of these six segments, four are small diameter socket-welded drains, vents, etc, and the remaining segments contain both a two-inch socket-welded section and three-inch butt-weld section (two welds each segment). The RRW value for the six segments is 1.005 (without operator action) and 1.000 (with operator action).

The use of the RRW value with operator action (1.000) for classification of these segments as LSS was based on:

- During normal power operation, these pumps are in standby operation (Vogtle generally uses the Normal Charging Pumps for charging); however, they are aligned to the Volume Control Tank (VCT). The alignment is such that a break in a 1" or greater segment will deplete the VCT at such a rate that there will be a Lo-Lo level signal and an automatic re-alignment to the Reactor Water Storage Tank (RWST).
- During charging operation using these pumps, the alignment is such that a break in a 3/4" or greater segment will deplete the VCT at such a rate that there will be a Lo-Lo level signal and an automatic re-alignment to the RWST.
- When aligned to the RWST, a high leak rate of 138 gpm for a period of 24 hours (or approximately 200,000 gallons) is required to cause the loss of the safety function (sump recirculation). Since these segments are located in a low radiation area subject to operator rounds, the expert panel was highly confident that the discovery of the leak, determination of the cause, and isolation of the leak via closure of the applicable motor-operated suction valve could easily be achieved within 24 hours.

In conclusion, with the combination of the automatic action upon the depletion of the VCT and the operator rounds, there was a high degree of confidence by the Expert Panel that the likelihood that the operators would fail to recover from the event for these segments was essentially zero. While these segments were lowered to LSS as allowed in the WCAP, the Expert Panel focused on adding piping to the higher classification; therefore, the intent of the Topical, WCAP-14572, Revision 1-NP-A, was met. Examples are:

- Seven unisolable RWST suction segments were elevated by the Expert Panel to HSS because of their high consequences (loss of RWST suction).
- Eighteen Main Steam and Feedwater segments between the containment and the first isolation valve were elevated by the Expert Panel to HSS because of their high consequences (loss of containment integrity in conjunction with a Steam Generator tube rupture).
- The segment downstream of the CVCS letdown flow orifices was elevated by the Expert Panel to HSS because of a potential for cavitation and the economic and cleanup considerations involved with the spillage of borated reactor coolant.

6. **NRC Request**

General - Please list the start and end dates for the second 10-Year ISI interval at Vogtle 1-2.

SNC Response

The start and end dates are as follow:

Unit 1
Commercial Operation Date: May 31, 1987
2nd 10 Year Interval Start: May 31, 1997
2nd 10 Year Interval End: May 30, 2007

Unit 2
Commercial Operation Date: May 20, 1989
2nd 10 Year Interval Start: May 31, 1997 (early update)
2nd 10 Year Interval End: May 30, 2007

7. **NRC Request**

Table 3.4-1 states that the highest failure probability in the CV system occurred downstream of the flow orifices due to the large pressure drop at the orifices and postulated potential for wall thinning. This would suggest the presence of cavitation effects. However, the dominant degradation mechanism is identified as erosion/corrosion. In WCAP-14572 and other sections of the submittal, erosion/corrosion refers to flow-accelerated corrosion (FAC) that is not expected to occur in austenitic stainless steel piping. Since it is our understanding that the CV piping downstream of the letdown flow orifices is normally austenitic stainless steel, please clarify what type degradation mechanism is actually present.

SNC Response

The potential for wall thinning is due to postulated cavitation. Wall thickness measurements will be taken downstream of the flow orifices.

8. **NRC Request**

Table 3.4-1 states, "A potential exists for thermal stratification and striping (NRC Bulletin 88-08) in small lines off the RCS; however, most of the lines are monitored, which substantially lowers the failure probability from this mechanism." Please describe the monitoring

program at Vogtle1 and Vogtle 2 for these locations and how its impact on pipe failure probability was determined. Also, please describe how the monitoring activities were credited or factored into RI-ISI evaluations and expert panel decisions.

SNC Response

Resistance Temperature Detectors (RTDs) were installed on the top and bottom of the piping identified in Vogtle's response to NRC Bulletin 88-08 (i.e., piping believed to be susceptible to thermal stratification and striping). In general, if a differential temperature between the upper and lower RTDs exceeds a specified value, then evaluations are performed to determine the cause of the temperature differential and the potential damage to the piping. For the lines that were identified as being monitored per NRC Bulletin 88-08, thermal stratification and striping were not modeled into the SRRA program as part of the piping failure probability. Therefore, the SRRA results for the monitored lines were not indicative of thermal stratification and striping, thus were not reflected in the calculated risk ranking values.

The "Interim Thermal Fatigue Management Guideline (MRP-24)" was used to screen those lines that are not monitored for their potential for cracking. The two-inch drain lines on the RCS intermediate loops (which are not monitored) did not pass the guideline screening criteria. Therefore, thermal stratification and striping were factored into their SRRA failure probability. The Expert Panel concurred with the SRRA modeling and the subsequent designation of HSS due to the potential for cracking.

9. NRC Request

Table 3.4-1 lists failure probability estimates for both Units 1 and 2, and indicates that there are no differences for any systems or pipe segments between for the two units. Did the evaluation include detailed considerations that could identify possible differences between the units in terms of operating experience, material properties, water chemistries, etc.?

SNC Response

Yes, an evaluation was performed in conjunction with discussions held with site engineers. Vogtle Unit 1 achieved commercial operation in 1987 and Unit 2 followed two years later in 1989. For the Class 1 and 2 Risk-Informed ISI scope, with only a two-year difference in age, the units are very similar in design and material properties. When there was a physical difference (e.g., different line size, etc) in a segment, the segment was

modeled separately for each unit. Many of the issues in the nuclear industry related to cracking (e.g., stagnant borated water cracking) were identified and rectified through the early establishment of chemical control and water chemistry specifications for both units. FatiguePro cycling and fatigue data for both units was reviewed. There were no identified significant operational events, within the Class 1 and 2 scope, to separate the two units.

10. <u>NRC Request</u>

In Section 3.8, the licensee stated, "The structural elements in the high safety significant [HSS] piping segments were selected for examination and appropriate NDE methods were defined." Further in this Section, the licensee stated, "Table 4.1-1 in WCAP-14752, A-Version, was used as guidance in determining the examination requirements for the HSS piping segments." There are several issues/questions regarding the application of NDE methods for piping in the RI-ISI program:

10a. Table 4.1-1 of the WCAP, A-Version, provides guidance for examination volumes (or areas), NDE methods, acceptance criteria, and examination scheduling for piping elements within the scope of the RI-ISI Program. The Table is based on format and criteria contained in ASME Section XI, IWB-, IWC-, and IWD-2500. The information contained in Table 4.1-1 has been adopted by ASME Code Cases N-577 and N-578, and is intended to replace the Code requirements in Section XI, IWB-, IWC-, and IWD-2500. The licensee stated that Table 4.1-1 was used as "guidance" in developing requirements for HSS piping segments. Based on a review of the licensee's submittal, it also appears that certain non-HSS piping segments have been selected for examination by the Expert Panel. Confirm that all requirements, as shown in Table 4.1-1, will be implemented for all piping within the scope of the RI-ISI program at Vogtle 1-2.

<u>SNC Response</u>

Except as identified below, all requirements, as shown in Table 4.1-1, will be implemented for all piping within the scope of the RI-ISI program at Vogtle unless specific written relief has been written and approved by the NRC. The exception is the requirements for "Elements Subject to Primary Water Stress Corrosion Cracking (PWSCC)." Table 4.1.-1 currently requires a VT-2 examination of an examination volume defined in Footnote 7; however, VT-2 examinations are not volumetric examinations. Therefore, when VT-2 examinations are performed each refueling outage they will be performed per the requirements set forth in Table IWB-2500-1 of the

Section XI Code. Additionally, Vogtle will perform appropriate examinations (volumetric, ID surface or visual, etc.) each inspection interval to detect ID originating PWSCC such as identified in Information Notice 2000-17.

10b. Confirm that all ultrasonic examinations applied to piping welds within the RI-ISI program (with the exception of wall thickness mapping), will meet the requirements of ASME Section XI, Appendix VIII for performance demonstration, or an alternative accepted by NRC Staff, such as the EPRI Performance Demonstration Initiative.

<u>SNC Response</u>

Ultrasonic examinations (with the exception of wall thickness mapping) are performed per the current Appendix VIII requirements and schedules specified in 10CFR50.55a regulations, except where proposed alternatives or exemptions have been approved by the NRC.

10c. Table 4.1-1 of the WCAP, A-Version, Footnote (3) states, in part, "When the required examination volume or area cannot be examined due to interference by another component or part geometry, limited examinations shall be evaluated by the Expert Panel for acceptability." In addition, Section 3.9 of the licensee's submittal states, "An attempt will be made to provide a minimum of >90% coverage of the examination volume (per Code Case N-460) when performing the risk-informed examinations. However, some limitations will not be known until the examination is performed, since some locations will be examined for the first time by the specified NDE techniques. In instances where an examination does not meet >90% coverage, a relief request will be submitted."

The NRC Staff is responsible for evaluating any limited examinations in accordance with 10CFR50.55a. Therefore, it is unclear how the Expert Panel will perform these evaluations, e.g., what acceptance criteria will be used, etc. and whether it is appropriate for the licensee to make these evaluations. Confirm that all limited examinations, as well as, any other deviations to ASME requirements or to Table 4.1-1 of the WCAP will be submitted to the NRC for approval.

SNC Response

When selected welds have limited accessibility (where > 90% coverage cannot be obtained), "Requests for Relief" from present ASME Code coverage requirements will be processed as per past procedures. The expert panel function is to make determinations if additional components should be examined.

11. NRC Request

Section 3.8 of the licensee's submittal addresses additional examinations. It states, "The evaluation will include whether other elements on the segment or segments are subject to the same root cause and degradation mechanism. Additional examinations will be performed on these elements up to a number equivalent to the number of elements initially required to be inspected on the segment or segments. If unacceptable flaws or relevant conditions are again found similar to the initial problem, the remaining elements identified as susceptible will be examined. No additional examinations will be performed if there are no additional elements identified as being susceptible to the same service related root cause conditions or degradation mechanism."

ASME Code directs licensee's to perform these sample expansions in the current outage that the flaws or relevant conditions were identified. Verify in what time frame the sample expansions will be completed.

SNC Response

Sample expansions will be performed in the outage where the flaws or relevant conditions were identified.

12. NRC Request

Withdrawn by the NRC.

13. NRC Request

The licensee has described an alternative approved by NRC Staff, to allow both units at Vogtle to have concurrent 10-Year ISI intervals (start and end dates). This was previously submitted as licensee's request for relief RR-1. The RI-ISI Program will be integrated into the existing 10-Year ISI Interval. However, in Section 3.9 the licensee

stated, "All other existing relief requests remain in place for the second interval."

Please list all other NRC-approved requests for relief for the second 10-Year interval at Vogtle 1-2 that are associated with the scope of piping examinations included in the RI-ISI Program. Describe how, if any, these existing relief requests will be impacted by or integrated into the RI-ISI piping examinations.

SNC Response

Other existing relief requests to remain in place for the second interval are:

- RR-9 – Primary Loop Piping Calibration Block and Scanning Requirements – Allows use of specific calibration blocks and scanning levels.

- RR-10, RR-11, RR-12, RR-13, RR-15, RR-16 - Defines limitations per the 1989 Section XI Code requirements. The degree of limitations will change when the welds in the RI-ISI scope are examined per Appendix VIII.

- RR-17 – Defines alternate Class 2 Piping Weld Selection Criteria. Risk Informed selection criteria will supersede this relief request.

- RR-18 – Redefines Nuclear Service Cooling Water Piping Classification. Risk Informed selection criteria will supersede this relief request.

- RR-36 – Implements Code Case N-598 to allow a change to the minimum/maximum number of examinations credited per period. This relief will continue to be used for RI-ISI piping examinations. (It should be noted that the NRC's issuance of Regulatory Guide 1.147, Revision 13 may supersede the use of RR-36.)

14. NRC Request

The licensee has proposed volumetric examinations on certain HSS small-bore reactor coolant piping as part of the new RI-ISI Program. In addition, in Section 3.10, the licensee has determined that large-bore reactor coolant loop piping is also HSS and "...will continue to be inspected and will also meet defense-in-depth considerations. The locations selected were associated with the reactor vessel dissimilar metal welds."

14a. Are all Code Category B-F dissimilar metal welds being volumetrically inspected in the RI-ISI Program? This includes B-F welds on the reactor pressure vessel, steam generator, pressurizer, and other piping welds.

SNC Response

No. There is a total of 22 dissimilar metal welds per unit. Eight reactor pressure vessel (RPV) and six pressurizer nozzle safe-end welds contain Inconel weld metal and have been included in the scope of examinations because of potential primary water stress corrosion cracking issues with Inconel that is in contact with the reactor coolant. The remaining eight dissimilar metal welds consist of stainless steel buttered nozzles located on the Steam Generators (SG). Four of these SG buttered nozzles are located on the same hot leg segments as the RPV Inconel welds and therefore not selected for examination. Two of the intermediate leg SG buttered nozzles were included in the examination scope. However, in lieu of examining the remaining two intermediate leg SG buttered nozzles, it was determined that to provide a sampling of other types of welds, two intermediate loop to Reactor Coolant Pump welds would be examined.

14b. Are any other Code Category B-J welds on large-bore RCS piping loops being volumetrically examined in the RI-ISI Program?

SNC Response

Yes. Two intermediate loop piping to Reactor Coolant Pump welds have been included in the scope of examination.

15. NRC Request

The licensee has previously been approved to allow both 10-Year ISI intervals at Vogtle 1-2 run concurrently. In Section 5.0, the licensee states, "The initial RI-ISI program is projected to start in second inspection period of the Second 10-Year ISI interval (both units ending the second period on May 31, 2004). Assuming approval, as projected:

*** Approximately 1/3rd of the required RI-ISI examinations will be performed during the second inspection period.**

*** Approximately 2/3rds of the required RI-ISI examinations will be completed by the end of the second 10-year ISI interval."**

15a. Describe the process for selecting examination locations to be distributed in the second and third periods of the Second 10-Year ISI interval.

SNC Response

Failure mechanisms, industry experience, site-specific experience, past inspection history, the presence of Code acceptable indications, stress considerations, etc. were considered when selecting welds for examination.

15b. When implementing a RI-ISI Program during a current interval, previous licensees have elected to prioritize examinations based on the relative risk ranking of the segments, i.e., implement examinations on the highest ranked segments first. However, it should be noted that the Code requires the sequence of examinations to be repeated during subsequent intervals, as practicable. Confirm that no greater than 10 years, as defined in ASME Section XI, will elapse between specific component examinations during the RI-ISI Program at Vogtle 1-2.

SNC Response

The 1989 Edition of ASME Section XI (current Vogtle Code of Record) requires that, "The sequence of component examinations established during the first inspection interval shall be repeated during each successive interval, to the extent practical." Vogtle will continue to meet this requirement. As an example, RI-ISI welds were scheduled based on past interval and period durations. For example, 1st interval, period 1 welds that are in RI-ISI scope were scheduled for the 2nd interval, period 1.

16. NRC Request

Tables 5-1a and 5-1b endnote (g) states that two CV VT exam locations and RC VT exam locations were added to Vogtle 1 and Vogtle 2 RI-ISI examination scope for change in risk considerations. Please describe what the VT exams are being added, their periodicity, and how the performance of these visual exams were considered in the change in risk assessment.

SNC Response

The VT examinations are VT-2 examinations of socket welded segments performed on a refueling outage frequency (18 months) while the system is under pressure. For the risk-informed program, credit was taken for an ISI examination for each segment in calculating the change in risk.

17. NRC Request

Tables 5-1a and 5-1b do not identify the SES region for any of the Class 1 CV piping and that the Class 2 HSS piping was placed in SES region two. For the structural element selection (SES) matrix, the topical report (WCAP-14572) states that a segment should be considered "high failure importance" if the 40 year cumulative large leak probability at any location in the segment is greater 10-4. Since Tables 3.7-1 and 3.7-2 state that 10 CV pipe segments have RRW values greater than 1.005 and Table 3.4-1 indicates that large leak 40 year failure probabilities could be as high as 2.18E-03, one would expect that there would be at least one CV pipe segment in SES region 1. Please explain.

SNC Response

Class 1 CV

The Class 1 segments identified in Table 5-1a and Table 5-1b are both Low Failure Importance (LFI) and Low Safety Significant (LSS). Therefore, they are in SES Region 4.

Class 2 CV

SNC's submittal dated July 26, 2002 does not identify any Class 2 SES Region 1 segments in Table 5-1a or Table 5-1b. However, after further review, one segment (per unit) is now being changed to SES Region 1. The bases for the Class 2 SES Region designations are:

- The ten Class 2 segments identified in Table 3.7-1 and Table 3.7-2 as having RRW values greater than 1.005 were originally designated as High Safety Significant (HSS), but were changed by the Expert Panel to LSS. (see the Response to NRC Request 5). These segments are Low Failure Importance (LFI) because the SRRA large leak failure probability is less than 10-4. Since they are LSS and LFI, they are SES Region 4.

- There are 11 Unit 1 segments and 12 Unit 2 segments that are High Failure Importance (HFI) because the SRRA large leak failure probability is greater than 10-4. However, they are LSS because the RRW values are less than 1.005 due to relatively low PRA consequences. Since they are LSS and HFI, they are SES Region 3.

- The segment (one per unit) downstream of the letdown flow orifices is HFI because the SRRA large leak failure probability is 2.18E-03. The high failure probability was based on industry issues with cavitation in these areas. However, it was originally designated as LSS since the RRW value is less than 1.005 because of the relatively low calculated PRA consequence. The Expert Panel elevated this segment to HSS because of potential future wall thinning even though previous examination of the base metal downstream of the flow orifices at Vogtle did not identify any wall thinning . Since it was HSS and HFI it was placed into SES Region 1 during the initial structural element selection.

- During Perdue modeling, it was concluded that Vogtle did not have an active degradation mechanism in this area because there was no evidence of wall thinning during examinations. Without an aggressive degradation mechanism and since the Perdue model verified an acceptable level of confidence with a single examination, the segment (one per unit) was moved to SES Region 2. However, after further evaluation, this segment will be reclassified as Region 1.