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SOUTHERN COMPANY
*Energy to Serve Your World* SM

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U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D. C. 20555-0001

Vogtle Electric Generating Plant
Response to a Request for Additional Information on Proposed Technical Specifications Change for Surveillance Test Interval Extensions for Components of the Reactor Protection System

Ladies and Gentlemen:

On January 27, 2005, Southern Nuclear Operating Company (SNC) submitted a proposed change to the Vogtle Electric Generating Plant (VEGP) Unit 1 and Unit 2 Technical Specifications (TS). The proposed changes will revise TS Limiting Conditions for Operation (LCOs) 3.3.1, 3.3.2, 3.3.6, and 3.3.8. Specifically, the Reactor Trip Breaker (RTB) bypass test time is relaxed from 2 hours to 4 hours, the completion time from 1 hour to 24 hours, and the Surveillance Frequency from 2 months to 4 months in TS LCO 3.3.1. The Surveillance Frequencies for the Logic Cabinet are relaxed from 2 months to 6 months, the Master Relays are relaxed from 2 months to 6 months, and the Analog Channels from 3 months to 6 months in TS LCOs 3.3.1, 3.3.2, 3.3.6, and 3.3.8. The proposed changes are based on Industry/TSTF Standard Technical Specification Change Traveler TSTF-411, Revision 1.

On July 13, 2005, SNC discussed the proposed changes with the NRC staff via telephone conferences and additional information was requested by the NRC staff in a letter dated July 26, 2005. SNC responses to the NRC staff's questions are enclosed.

(Affirmation and signature are provided on the following page.)

Mr. D. E. Grissette states he is a Vice President of Southern Nuclear Operating Company, is authorized to execute this oath on behalf of Southern Nuclear Operating Company and to the best of his knowledge and belief, the facts set forth in this letter are true.

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

Respectfully submitted,

SOUTHERN NUCLEAR OPERATING COMPANY

Don E. Grissette

*Sworn to and subscribed before me this* 30th *day of* September, *2005.*

*Notary Public*

*My commission expires:* 11/10/06

DEG/DWM/daj

Enclosure: Response to a Request for Additional Information on Proposed Technical Specifications Change for Surveillance Test Interval Extensions for Components of the Reactor Protection System

cc: Southern Nuclear Operating Company
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Mr. T. E. Tynan, General Manager – Plant Vogtle
RType: CVC7000

U. S. Nuclear Regulatory Commission
Dr. W. D. Travers, Regional Administrator
Mr. C. Gratton, NRR Project Manager – Vogtle
Mr. G. J. McCoy, Senior Resident Inspector – Vogtle

State of Georgia
Mr. L. C. Barrett, Commissioner – Department of Natural Resources

Vogtle Electric Generating Plant
Response to a Request for Additional Information on Proposed Technical Specifications Change for Surveillance Test Interval Extensions for Components of the Reactor Protection System

Enclosure

1.0 For Condition 2 on page of E1A-12 of the licensee's submittal, dated January 27, 2005, (submittal), the licensee stated that the recommended Tier 2 restrictions will be incorporated into the work planning procedures and the Tier 3 requirements are addressed through the normal work planning process consistent with the requirements of Title 10 of the *Code of Federal Regulations* (10CFR) part 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants," section (a)(4), .

1. Page E1A-12 of the submittal states that the Tier 3 requirements are addressed through the normal work planning process consistent with the requirements of 10 CFR 50.65(a)(4). Provide a discussion on the applicability of the Vogtle Electric Generating Plant (VEGP) 10 CFR 50.65(a)(4) configuration risk management program (CRMP)-based program regarding whether it meets the additions and clarifications provided in Regulatory Guide (RG) 1.177, "An Approach for Plant-Specific, Risk-Informed Decision Making: Technical Specifications," Section 2.3.7.2, Key Components 1 through 4, for CRMP programs that implement Section a(4) of 10 CFR 50.65(a)(4).

**SNC RESPONSE**

RG 1.177, Section 2.3.7.2, Key Components 1 through 4 refer to RG 1.160, which was published prior to implementation of 10 CFR 50.65(a)(4). As such, guidance provided in RG 1.182, which endorses NUMARC 93-01, section 11, is more suitable for applications that require a commitment to a CRMP. The Vogtle Maintenance Scheduling Procedure, 00354-C implements the CRMP required by TS 5.5.18 and provides instructions to conduct risk-informed assessments required by MR 10 CFR 50.65 (a)(4) consistent with NUMARC 93-01, section 11. As stated in TS 5.5.18, the CRMP applies to TS structures, systems or components (SSCs) for which a risk-informed allowed outage time has been granted. It includes the following elements:

a. Provisions for the control and implementation of a Level 1 at power internal events PRA-informed methodology. The assessment shall be capable of evaluating the applicable plant configuration.

b. Provisions for performing an assessment prior to entering the LCO Condition for preplanned activities.

c. Provisions for performing an assessment after entering the LCO Condition for unplanned entry into the LCO Condition.

d. Provisions for assessing the need for additional actions after the discovery of additional equipment out of service conditions while in the LCO Condition.

e. Provisions for considering other applicable risk significant contributors such as level 2 issues and external events, qualitatively or quantitatively.

In addition to the above attributes, NUMARC 93-01, section 11 provides guidance for the scope of SSCs subject to the assessment during power operations (section 11.3.3) and SSCs subject to the assessment during shutdown (section 11.3.5), assessment methods for power operating and shutdown conditions (sections 11.3.4 and 11.3.6), and guidance on managing risk (section 11.3.7). The VEGP implementation of 10 CFR 50.65(a)(4) is consistent with this above guidance.

2. Identify the manner in which VEGP programs will address the following restrictions identified in the Nuclear Regulatory Commission (NRC) staff's approval of the Westinghouse Commercial Atomic Power (WCAP)-15376 report, "Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times." Confirm that the following Tier 2 restrictions as identified by WCAP-15376 remain bounding for the plant specific implementation at VEGP.

- Activities that could degrade the availability of the auxiliary feedwater system, reactor coolant system pressure relief (pressurizer power-operated relief valves and safety valves), AMSAC, or turbine trip should not be scheduled when a reactor trip breaker (RTB) is out of service.

- Activities that could degrade other components of the reactor protection system, including master relays or slave relays and activities that cause analog channels to be unavailable should not be scheduled when a logic cabinet is unavailable.

- Activities on electrical systems that support the systems or functions listed in the first two bullets should not be scheduled when an RTB is unavailable.

**SNC RESPONSE**

As indicated in the response to Question 1 above, VEGP procedure 00354-C, "Maintenance Scheduling", implements the Configuration Risk Management Program (CRMP) required in Operating Modes 1, 2, 3, and 4. VEGP procedure 00354-C has requirements that any of the activities described below must be specifically evaluated for impact on plant safety, using EOOS (EQUIPMENT OUT OF SERVICE SAFETY MONITOR - a computer based program for assessing the impact on plant safety of equipment configurations) prior to removing the equipment/system from service unless continued operation of the system could result in further damage or undesirable plant conditions.

This includes work or testing requiring entry into risk informed Action Conditions in Technical Specification sections 3.3.1 (RTS Instrumentation) and 3.3.2 (ESFAS Instrumentation). Work or testing which removes a Solid State Protection System (SSPS) train from service has the following special requirements:

- No other scheduled work which degrades the availability of AMSAC, AFW, PORVs, RCS code safeties, or turbine trips for ATWS mitigation

- One complete train of ECCS must be available for automatic actuation

- No work scheduled on the other SSPS train or its RPS/ESF inputs

- No work scheduled on electrical and cooling systems (NSCW, CCW) for the three systems or functions above

These requirements will be reviewed considering WCAP-15376 restrictions, and procedure 00354-C will be revised accordingly, prior to implementation of this proposed amendment, to restrict work on the available train when a Reactor Trip Breaker is out of service during the following conditions:

- The probability of failing to trip the reactor on demand will increase when a RTB is removed from service, therefore, activities that could degrade the availability of the auxiliary feedwater system, reactor coolant system pressure relief (pressurizer power-operated relief valves and safety valves), AMSAC, or turbine trip should not be scheduled when a reactor trip breaker (RTB) is out of service.

- Due to increased dependence on the available reactor trip train when one logic cabinet is removed from service, activities that could degrade other components of the reactor protection system, including master relays or slave relays and activities that cause analog channels to be unavailable should not be scheduled when a logic cabinet is unavailable.

- Activities on electrical systems that support the systems or functions listed in the first two bullets should not be scheduled when an RTB is unavailable. Based on current plant configuration, the Tier 2 restrictions as identified by WCAP-15376 are bounding for the plant specific implementation at VEGP.

2.0 Provide a discussion on the following aspects of probabilistic risk assessment (PRA) quality as applicable to the VEGP PRA.

**SNC RESPONSE:**

By NRC letter dated December 20, 2002, the staff approved Westinghouse topical report (TR) WCAP-15376-P, "Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times." As permitted by the staff in their December 20, 2002 letter, SNC filed the license amendment application for VEGP based upon the NRC staff's approval of WCAP-15376-P. The five conditions stipulated in the NRC approval did not involve use of the VEGP PRA to calculate either the changes in CDF and LERF, or ICCDP on a plant-specific basis for justifying the license amendment. As a result, responses to some of the following questions do not reflect a direct consequence of VEGP PRA model manipulation.

1. Whether, the plant-specific PRA reflects the as-built, as-operated plant.

**SNC RESPONSE**

The models developed in the IPE represented the as-built, as-operated, as-maintained VEGP as of January 1, 1991. Subsequent to the IPE, the Vogtle PRA model was converted from the Large Event Tree methodology based on the Westinghouse GRAFTER and WESCUT computer codes to a Linked Fault Tree methodology based on the Electric Power Research Institute (EPRI) Computer Aided Fault Tree Analysis (CAFTA) computer code suite. This conversion was completed in March 1998 and the resulting model was designated as Revision 0 of the Vogtle PRA. Revision 0 incorporated plant design features to account for power supply from Plant Wilson, a combustion turbine facility located close to the VEGP site and described in detail on the VEGP Docket by letter dated January 22, 1998 (LCV-1111). Revision 1 of the Vogtle PRA was issued in August 1999. This revision continued the refinement of the CAFTA Linked Fault Tree model and incorporated a number of new operator actions. Revision 2 of the Vogtle PRA was issued in January 2000. This revision updated the basic event data used, and incorporated plant design changes through April 20, 1998. The data used for the basic event update was collected from the plant operating and maintenance records for both units for the time period January 1, 1991 through November 1, 1998. Subsequent to the Westinghouse Owners Group (WOG) peer review, the VEGP PRA model was updated to Revision 2cy, dated 11/24/2003, in order to resolve three items which were considered to be the most significant Level "B" items (see response to question 2.3 below for a discussion of the level B findings that were incorporated.) Revision 2cy is the approved model on record.

2. Applicable PRA updates conducted since completion of individual plant examination (IPE) and individual plant examination of external events (IPEEE) and the status of any improvements identified by the IPE and IPEEE.

**SNC RESPONSE**

Response to question 2.1 above discusses the PRA updates conducted since the completion of the IPE. The approved model on record reflects improvements identified by the IPE that have been implemented. The IPEEE model has not undergone any revisions since the results were submitted to the NRC. The IPEEE analysis did not identify any fundamental weaknesses or vulnerabilities that required any plant improvements.

3. Conclusions of the peer review including any facts and observations (A and B) applicable to the proposed extended surveillance test interval (STI) and completion times (CTs) and their resolution. If not resolved, provide justification for acceptability (e.g., sensitivity studies showing negligible impact). Indicate the PRA revision that underwent peer review and the PRA revision used in this application.

**SNC RESPONSE**

The VEGP PRA model, Revision 2c, dated 08-28-2001 was reviewed by the WOG Peer Review Team in December 2001. The Peer Review findings, "Contingency Grade 3" items were categorized into four levels of significance (A, B, C, or D), with Level "A" being the most significant. None of the "Contingency Grade 3" items were judged by the Peer Review Team as Level "A" which would have required prompt resolution to ensure the technical adequacy of the PRA. Level "B" observations identified were considered important for the long-term enhancement of the PRA model, their resolution is allowed to be deferred until the next periodic PRA model update.

NRC approval of WCAP-15376-P was the basis for the proposed TS change. However, as required by the conditional NRC approval of WCAP-15376-P, certain information from the VEGP PRA model, Revision 2cy was submitted to the NRC as part of the plant-specific TS submittal. The VEGP PRA model, Revision 2cy reflects the following resolutions for the three findings deemed most significant among all the Level "B" findings.

1) Re-evaluation of RHR pump common cause failure (CCF) probabilities using the most recent NRC CCF data base (observation DA-02)
2) Re-binning all steam generator tube rupture sequences into containment bypass sequences in the LERF model (observation AS-08), and
3) Adding RHR pump demand failures to low pressure recirculation fault tree for small LOCA (observation QU-06).

As discussed below, the impact of not incorporating resolutions to the remaining Level "B" findings on the proposed RPS and ESFAS extended surveillance test interval (STI) and completion times (CTs) are not considered to adversely impact the conclusions WCAP-15376-P and the supporting information from the VEGP PRA that was submitted to the NRC as part of the TS submittal. Since Level "C" and "D" items have less risk significance, their impacts were not further evaluated.

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

The VEGP PRA model has a single event which represents the fail to run probability for all NSCW pumps (four running and two standby pumps) due to a common cause failure (CCF). In order to evaluate the probability of the CCF event, the fraction of historical CCF events which could affect both normally running and standby pumps was calculated and multiplied by the probability of CCF event only among normally running pumps. The fractional number was estimated to be 0.4 based on the recent NRC CCF data base. The observation suggested that use of 0.4 as the fractional number might be non-conservative because the difference in system size between VEGP NSCW system and the other systems in the data base were not adjusted in calculating the fraction. However, according to recent VEGP specific CCF evaluations, the fraction, if the size difference is adjusted, is less than 0.4.

Furthermore, since the CCF event is a single event core damage minimal cutset and has no relationship to the RPS and ESFAS failures, the core damage frequency due to the CCF event would not be affected by the proposed RPS and ESFAS extended surveillance test interval (STI) and completion times (CTs).

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

The major issue in this observation was that for some of the ISLOCA scenarios which include breaks at the suction of high pressure safety injection systems, high pressure safety injection could not be credited as it was credited in the VEGP PRA model. For those scenarios, an ISLOCA initiating event would directly lead to core damage, which could increase baseline CDF and LERF values.

A review of the ISLCOA frequency evaluation revealed that the frequencies for those ISLOCA scenarios which could affect the high pressure safety injection system were based on very conservative assumptions such as no credit for operator recovery actions and no credit for relief valves. Use of more realistic assumptions would reduce the frequency of such scenarios by several orders of magnitude and their contribution to the total ISLOCA risk would become insignificant.

Furthermore, if it is assumed that those ISLOCA scenarios are assumed to cause direct core damage, they would have no relationship to the RPS and ESFAS failures and the CDF due to such ISLOCA scenarios would not be affected by the proposed RPS and ESFAS extended surveillance test interval (STI) and completion times (CTs).

(3) 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 when 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 not incorporating this item is not expected to adversely impact the conclusions made for the proposed RPS and ESFAS extended surveillance test interval (STI) and completion times (CTs) because ATWS contributes less than 0.01% of the total CDF and less than 0.1 % of the total LERF.

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

The WOG peer review finding recommended the addition of a reference, or basis, for the time window for each operator action. The timing information for the HRA for the VEGP PRA was based on generic timing information from Westinghouse and information from interviews with groups of Senior Reactor Operators and Operators at VEGP. Any deviation of plant-specific timing information from generic timing information is not expected to adversely impact the conclusions

made for the proposed RPS and ESFAS extended surveillance test interval (STI) and completion times (CTs). This belief 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.

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

Since the VEGP PRA internal flooding results were based on a thorough analysis which included a pre-walk down screening, plant walk down, and final evaluation, it is expected that re-examining internal flooding analysis would not identify any new significant contributors to the risk associated to the internal flooding. Thus, the impact of not incorporating this item will not adversely affect the conclusion made for the proposed RPS and ESFAS extended surveillance test interval (STI) and completion times (CTs).

(6) 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 circumstance described by this WOG PEER review finding is not expected to adversely affect the conclusions made for the proposed RPS and ESFAS extended surveillance test interval (STI) and completion times (CTs) because of the conservatism used in the VEGP PRA model.

(7) 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 is not constant in this time frame."*

This comment originated from the reviewer's misunderstanding of the event OA-OSPR-----H. OA-OSPR-----H is not the probability of offsite power recovery within X hours. It is an operator error probability for failure to restore AC power from reserve aux transformers. The VEGP PRA model uses different offsite power (LOSP) non-recovery probabilities in different time frames. Thus, this item will not affect the conclusions made for the proposed RPS and ESFAS extended surveillance test interval (STI) and completion times (CTs).

(8) 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 DGs hardware failure probability, especially CCFs, be included. A sensitivity study on the value of the event, which was performed along with DG mission time (see item (11), observation QU-03), revealed that the impact of not incorporating this item is not expected to adversely affect the conclusions made for the proposed RPS and ESFAS extended surveillance test interval (STI) and completion times (CTs).

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

The mission time (2 hours) for DGs used in the VEGP PRA model is the weighted time DGs must run during the 24 hour mission time considering the probability of offsite power recovery. The current modeling is considered to be more realistic. Consequently, it is considered that the circumstance described by this WOG PEER review finding will not adversely impact the conclusion made for the proposed RPS and ESFAS extended surveillance test interval (STI) and completion times (CTs).

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

Each VEGP PRA model revision including the original IPE was reviewed either by an in-house independent reviewer or independent consultants. An additional major review was performed by the WOG Peer Review Group. Thus, given the developmental history of the VEGP PRA, the lack of a systematic comparison of VEGP PRA results with other similar plants' results is not expected to adversely affect the conclusions made for proposed RPS and ESFAS extended surveillance test interval (STI) and completion times (CTs).

4. Reference PRA quality assurance programs/procedures, including expected PRA revision schedules.

**SNC RESPONSE:**

The VEGP PRA is documented as a PRA calculation in accordance with SNC procedures PS-PRA-008, Version 1, "PRA Calculations – Preparation and Revision," and PS-PRA-009, Version 1, "PRA Calculation Administration." The PRA revision schedule is controlled by SNC procedure PS-PRA-001, Version 2, "Generation and Maintenance of Probabilistic Risk Assessment Models and Associated Updates." The general guidelines state that pertinent modifications to the physical plant shall be reviewed to determine the scope and necessity of a revision to the baseline model within six months following either a periodic refueling outage or a specific major plant modification occurring outside a refueling outage. Modifications to procedures, technical specifications, reliability data, failure data, initiating events frequency data, human reliability data and other such PRA inputs shall be reviewed for

statistical significance approximately every three years. The PRA is updated as necessary in accordance with a schedule approved by the PRA Services Supervisor following the scoping review.

5. PRA adequacy and completeness with respect to evaluating the proposed STI and CT extensions.

**SNC RESPONSE**

The proposed STI and CT extensions are based on the generic analysis documented in the staff approved Westinghouse topical report (TR) WCAP-15376-P and the supporting information from the VEGP PRA submitted to the NRC. The adequacy and completeness of the PRA used for WCAP-15376-P for evaluating the proposed STI and CT extensions were considered as part the generic analysis performed by WOG and determined to be adequate for evaluating the proposed STI and CT extensions. The adequacy and completeness of the VEGP PRA with respect to the validity of the supporting information provided to the NRC is demonstrated in response to question 2 above.

6. Plant design or operational modifications not reflected in the PRA revision used in this application that are related to or could impact this application. Justify the acceptability of not including these modifications in the PRA as part of this application.

**SNC RESPONSE**

We know of no plant design or operational modifications related to or that impact this application that are not reflected in the PRA.

3.0 Provide an evaluation of external events risk impact including, seismic, fire, and external floods/high wind risk with respect to the proposed CT and STI extensions.

**SNC RESPONSE**

(1) Seismic:

Although a seismic PRA has not been developed, a seismic margins assessment (SMA) for resolution of the seismic portion of NRC GL 88-20, Supplement 4 entitled "Individual Plant Examination of External Events (IPEEE) for Severe Accidents," was performed for VEGP. The SMA review level earthquake for VEGP is a 0.3 g peak ground acceleration (PGA) NUREG/CR-0098 spectrum. VEGP structures and equipment were designed for a safe shutdown earthquake (SSE) defined by a Regulatory Guide 1.60 spectrum tied to a PGA of 0.2 g. However, due to conservatisms applied to the demand and/or evaluation techniques, most of the Seismic Category 1 structures and equipment were designed and qualified for a 0.3 g PGA capacity. Based on the results of the SMA evaluations, VEGP Units 1 and 2 have a high-confidence-low-probability-of-failure capacity of at least 0.3 g PGA.

Furthermore, the probability of an earthquake greater than 0.3 g PGA occurring during the additional time of the proposed RPS and ESFAS extended surveillance test interval (STI) and completion times (CTs) is on the order of 3.84E-07 (based on Vogtle-specific hazard curve from NUREG 1488 assuming that the worse case contribution is attributed to the CT extension). Even if it is assumed that the conditional probability of core damage is 0.1, the seismic contribution would likely be on the order of 3.84E-08. Therefore any seismic-related increase in risk due to the proposed RPS and ESFAS extended surveillance test interval (STI) and completion times (CTs), although not quantified, is expected to be negligible.

Consequently, it is expected that the conclusion made for the proposed RPS and ESFAS extended surveillance test interval (STI) and completion times (CTs), will remain unaffected with a lack of accounting for seismic risk contribution.

(2) Fire:

A fire PRA was performed for Vogtle in response to the request of Generic Letter 88-20, Supplement 4 entitled "Individual Plant Examination of External Events (IPEEE) for Severe Accidents." The objective of the analysis was to identify fire and smoke induced plant-specific vulnerabilities to severe accidents. Based on the results of the analyses, the total fire core damage frequency (CDF) was reported to be 1E-05 per year. Using the fire CDF reported in the IPEEE, the total combined base line CDF (internal events plus fire risk) is 1.71E-05 + 1.01E-05 = 2.72E-05 per year, which is less than 1E-04 per year. Therefore Regulatory Guide 1.174 criteria can still be used to determine acceptability of the total (internal plus fire) CDF increase resulting from proposed RPS and ESFAS extended surveillance test interval (STI) and completion times (CTs).

An evaluation was performed to determine the potential impact of the fire CDF reported in the IPEEE for the top three fire zones on the proposed RPS and ESFAS extended surveillance test interval (STI) and completion times (CTs).

Based on a review of the IPEEE fire analyses results, the main control room, 4160 volt train A switchgear room, and 4160 volt train B switchgear room are the top three fire zones in terms of fire CDF. The dominant impacts in the fire core damage sequences analyzed in the IPEEE for these three fire zones are fire-related LOSP and failure of AC power equipment. In these sequences, core damage is mitigated by an operator action to manually open the steam admission valve and local/manual operation of the TDAFW pump. Since the success or failure of these TDAFW pump related operator actions are not affected by RPS and ESFAS unavailability, it is expected that the increase in fire risk due to the proposed RPS and ESFAS extended surveillance test interval (STI) and completion times (CTs) would be small. Consequently, it is expected that the conclusion made for the proposed RPS and ESFAS extended surveillance test interval (STI) and completion times (CTs) will remain unaffected with a lack of accounting for fire risk contribution.

(3) High Winds

According to VEGP IPEEE, VEGP conforms to the Standard Review Plan, NUREG 75/087, criteria regarding high winds and tornadoes. Also there have been no significant changes that would adversely affect the high winds design basis at VEGP since the issuance of the operating license. Thus, it is expected that the risk associated with high winds is small and that the conclusion made for the proposed RPS and ESFAS extended surveillance test interval (STI) and completion times (CTs) will remain unaffected with a lack of accounting for high wind risk contribution.

(4) Freezing rains

According to the VEGP FSAR, freezing rain is rare at the VEGP site. Furthermore, loss of offsite power events due to freezing rains were included in the calculation of the loss of offsite power initiating event frequency. Thus, the impact of freezing rain has already been considered in the proposed RPS and ESFAS extended surveillance test interval (STI) and completion times (CTs).

4.0 Provide an evaluation of cumulative risk impact including previous TS changes per Regulatory Guide (RG) 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Current Licensing Basis," Section 3.3.2 guidance.

**SNC RESPONSE**

The impact of plant changes on the actual cumulative risk is a strong function of operating experience (initiating event frequencies, failure data, etc.) and will be known when the PRA undergoes the scheduled periodic updates. The following provides the calculated delta CDF and delta LERF for each of the post-RG 1.174 applications which provide an indication and may not have a one-to-one correlation to the actual change in CDF and LERF based on operating experience.

| Item No | Date | Calculated Internal Events Delta CDF | Calculated Internal Events Delta LERF | Application |
|---|---|---|---|---|
| 1 | 10/1999 | <1E-06 | <1E-07 | Reactor Trip System Instrumentation /LCO 3.3.2, ESFAS Instrumentation |
| 2 | 11/2003 | 1.54E-8 | | ECCS Accumulators |
| 3 | 01/2004 | | 6.0E-07 | ILRT – includes external events contribution |
| 4 | 03/2005 | 1.7E-07 | 1.0E-10 | Battery AOT Extension |
| Total | | 1.19E-06 | 7.0E-07 | |

5.0 Regarding the Additional Condition on page E1A14 of the submittal, the NRC staff requires that each plant review its setpoint calculation methodology and assumptions to determine the impact of extending the STI of the COT from 92 to 184 days. Please address in detail the results of the licensee's review of the setpoint calculation methodology and assumptions.

**SNC RESPONSE**

SNC's initial submittal stated: "Plant Vogtle has in place a process for trending Technical Specification instruments performance. The trending information is obtained from the calibration data sheet(s). The recorded "as found" and "as left" values are placed into a trending database and evaluated by the system engineer. This assures that the values remain within the drift allowances used in the setpoint methodology. If pre-determined limits are exceeded, the condition is reported in the plant Condition Reporting and Tracking System. The pre-determined limits are set within the Allowable Values specified in Tech Spec Tables 3.3.1-1 and 3.3.2-1. A review of COT trending data has indicated that the instrument loops will remain within existing Technical Specification and uncertainty calculation limits should the COT frequency change to 184 days."

This review noted that a comparison of the "as found" to previous "as left" data resulted in drift magnitudes that are well within the process rack operability criteria specified by the Plant Vogtle procedures and consistent with operability criteria for a healthy channel as defined by the process rack vendor. No bias or significant adverse trends were noted. No history of frequent process rack recalibration was noted in this review for the current COT frequency. Therefore, it is concluded that the extension of the COT frequency to 184 days will not affect the assumptions of the setpoint calculation methodology and the expected process rack drift will remain consistent with current operability criteria.