November 16, 2007

LICENSEE: Southern Nuclear Operating Company, Inc

FACILITY: Vogtle Electric Generating Plant, Units 1 and 2

SUBJECT: SUMMARY OF CONFERENCE CALL WITH SOUTHERN NUCLEAR OPERATING COMPANY, INC., TO DISCUSS THE SEVERE ACCIDENT MITIGATION ALTERNATIVES REQUESTS FOR ADDITIONAL INFORMATION FOR VOGTLE ELECTRIC GENERATING PLANT, UNITS 1 AND 2 (TAC NOS. MD5905, MD5906)

On October 29, 2007, the U.S. Nuclear Regulatory Commission (NRC) staff and its contractors from Pacific Northwest National Laboratory conducted a conference call (teleconference) with representatives from Southern Nuclear Operating Company, Inc. (SNC), and its contractors from Tetra Tech and ERIN Engineering and Research, Inc., to discuss the Vogtle Electric Generating Plant, Units 1 and 2 (VEGP) severe accident mitigation alternatives (SAMA) requests for additional information (RAIs) (ML072750508). The NRC staff formally sent the SAMA RAIs to SNC by letter dated October 24, 2007, in support of the environmental review of the VEGP application for license renewal (ML072841107).

SNC staff and contractors discussed SAMA RAI's with NRC staff and contractors and gained clarification as to specific line items. SNC agreed to provide the requested information within the 60 day period outlined in the formal RAI request letter. No staff decisions were made during the teleconference.

/RA/

J.P. Leous, Project Manager
Projects Branch 1
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket Nos. 50-424 and 50-425

Enclosures:
1. List of Participants
2. SAMA RAI List

cc: See next page

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Letter to Southern Nuclear Operating Co. Inc., From JP Leous Dated, November 16, 2007

SUBJECT: SUMMARY OF CONFERENCE CALL WITH SOUTHERN NUCLEAR OPERATING COMPANY, INC., TO DISCUSS THE SEVERE ACCIDENT MITIGATION ALTERNATIVES REQUESTS FOR ADDITIONAL INFORMATION FOR VOGTLE ELECTRIC GENERATING PLANT, UNITS 1 AND 2 (TAC NOS. MD5905, MD5906)

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WITH SOUTHERN NUCLEAR OPERATING COMPANY, INC.
LIST OF PARTICIPANTS

October 29, 2007

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Bruce Schmitt	PNNL
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Enclosure 1

REQUEST FOR ADDITIONAL INFORMATION
REGARDING THE ANALYSIS OF SEVERE ACCIDENT MITIGATION ALTERNATIVES
FOR THE VOGTLE ELECTRIC GENERATING PLANT, UNITS 1 AND 2

The Environmental Report (ER) failed to include key information in a number of areas related to the analysis of Severe Accident Mitigation Alternatives (SAMA) for Vogtle Electric Generating Station (VEGP), Units 1 and 2. The following information is considered both necessary in order for the NRC staff to complete its evaluation, and within the scope of Nuclear Energy Institute (NEI) 05-01, "Severe Accident Mitigation Alternatives (SAMA) Analysis Guidance Document."

1. Provide the following information regarding the development of the VEGP probabilistic risk assessment (PRA) used for the SAMA analysis for VEGP, Units 1 and 2.

    a. Attachment F to the ER does not cite to which unit the internal events core damage frequency (CDF) applies. Provide the internal events CDF for the other unit if different, and a discussion of the reasons for any differences. Discuss the impact on the SAMA analysis and results if the analysis were based on the other unit.

    b. Section F.5.1.6.1 notes that the total internal events CDF has been reduced from 4.90E-05 per year (Individual Plant Evaluation (IPE)) to 1.55E-05 per year (current PRA) due to "various improvements and enhancements to the model." Table 2.1 lists the items updated in each PRA revision, but this table does not identify any plant changes, or include any information regarding the CDF or large early release frequency (LERF) for each revision.

        i. Provide a description of any plant changes (hardware or procedure) reflected within each PRA revision.

        ii. Provide the total CDF and LERF estimates for each of the major PRA revisions (e.g., IPE, Rev 0, Rev 1, Rev 2, Rev 3, and VEGPL2UP).

        iii. Identify the major reasons for the change in CDF and LERF in each of the major revisions.

        iv. Identify any plant changes since the VEGPL2UP model and provide a qualitative assessment of their potential impact on the PRA and the results of the SAMA evaluation.

    c. The only mention of the breakdown of contributors to internal events CDF occurs in Section F.5.1.6.1 in the context of the fire events discussion. Provide a breakdown of the contributions to internal events CDF by initiating event for PRA version VEGPL2UP.

    d. Provide a list and description of the top 30 cutsets from the Level 1 model, and the plant damage states for each of the cutsets.

    e. Describe any credit taken for equipment in the opposite unit and the assumptions concerning this equipment's availability as a result of conditions at the other unit.

f. Provide additional information concerning the CDF sequences involving reactor coolant pump (RCP) seal loss-of-coolant accidents (LOCAs) due to either support system failure and station blackout (SBO) including the VEGP RCP seal design, associated seal injection and cooling systems, dependencies of these systems on other support systems, related emergency core cooling systems or makeup system dependencies and how the RCP seal failure is modeled in the VEGP PRA.

g. Table F.2.2 provides Westinghouse Owners Group (WOG) peer review comment resolutions that were incorporated into Revision 3 to the VEGP PRA. Section F.2 indicates that all WOG peer review "B" findings were addressed in PRA model Revision 3. However, PRA version VEGPL2UP was subsequently developed to support the SAMA analysis.

   i. Identify which version of the VEGP PRA was peer reviewed by the WOG.

   ii. Discuss any subsequent internal or external peer reviews that have been performed of PRA version VEGPL2UP. Describe any significant review comments and their potential impact on the results of the SAMA analysis.

h. Section F.2.2 indicates that the CDF event tree structure was re-constructed to incorporate additional success terms needed to support the refined Level 2 modeling in PRA version VEGPL2UP, and that the base model CDF with success branches accounted for is slightly lower than the base model CDF without success branches accounted for.

   i. Provide examples of the previous and the re-constructed versions of the Level 1 event trees to help illustrate the changes made in PRA version VEGPL2UP. Confirm the PRA version to which the "previous Vogtle Level 1 base model" refers.

   ii. Confirm that PRA version VEGPL2UP includes success criteria in the event tree quantification to support the Level 2 analysis. If so, explain why the CDF value of 1.55E-05 per year (based on model without success branches) is used as the base risk in the Section F.6 analyses rather than the CDF value of 1.529E-05 per year (based on model with success branches).

2. Provide the following information relative to the Level 2 analysis:

   a. Provide a description of the evolution of the Level 2 model prior to PRA version VEGPL2UP.

   b. Provide an expanded discussion of the changes to the Level 2 model implemented in PRA version VEGPL2UP (which are alluded to in Section F.2.1 and F.2.2.). Include a further description of the assumptions in the revised model that result in a zero frequency of LERF sequences with early containment failure due to severe accident phenomena (LERF-CFE) and small early release frequency sequences.

c. Level 2 release categories are defined in Section F.2.1, and a representative sequence for each release category is identified in Table F.3.1. Describe the methodology for binning Level 1 sequences into the Level 2 release categories, and the approach used to identify the representative sequence for each release category. Address whether sequence selection was based on the frequencies, consequences, timing, or some other consideration of the various sequences assigned to each release category.

3. Provide the following information with regard to the treatment and inclusion of external events in the SAMA analysis:

a. In Section F.5.1.6.1, Southern Nuclear Corporation (SNC) provides the CDF for the ten largest contributing fire scenarios, and identifies Phase II SAMAs (based on insights from the internal events PRA) that would help reduce the fire risk for each fire area. The top ten fire scenarios constitute less than 45 percent of the total fire PRA CDF. Provide a similar discussion for all fire areas contributing up to 95 percent of the fire CDF, or rationale as to why SAMAs to address these additional fire areas need not be considered.

b. For each of the dominant fire areas, explain what measures have already been taken to reduce risk. Include in the response specific consideration of improvements to detection systems, enhancements to suppression capabilities, changes that would improve cable separation and drain separation, and monitoring and controlling the quantity of combustible materials in critical process areas. Explain why the fire CDF can not be further reduced in a cost effective manner through implementation of SAMAs specific to fire events.

c. In Section F.5.1.6.1, a list of PRA topics that prevent the effective comparison of the CDF between the internal events PRA and the fire PRA is provided. These topics appeared to be derived from NEI 05-01, and are provided as general statements rather than specific arguments applicable to the VEGP fire PRA. State how these assumptions apply to the VEGP fire PRA.

d. The assumption that risks posed by external and internal events is approximately equal (page F-48) appears to be based on the fire PRA (individual plant examination of external events) only being 21 percent of the original IPE CDF value of 4.90E-05 per year. However, the fire PRA CDF represents over 66 percent of the internal events CDF from the VEGPL2UP model used in the SAMA analysis. Provide further justification that the factor of two multiplier is adequate to account for the additional risk from all external events (e.g., seismic, fire, high winds, etc.).

4. Provide the following information concerning the MACCS2 analyses:

a. The discussion on pages F-17 and F-18 indicates that a factor of 1.84 was applied to evacuation, relocation, decontamination and property condemnation costs to account for cost escalation since the time these values were first specified in the MACCS2 Sample Problem A. Describe how the scaling factor of 1.84 was derived for cost escalation between 1986 and 2006. Also, identify and

briefly discuss the key MACCS2 input assumptions or other factors that contribute to the offsite economic cost risk at VEGP (e.g., daily cost for relocated individuals, the costs to relocate an individual, daily cost for evacuated individuals, cost of farm and non-farm decontamination, the value of farm and non-farm wealth, cost of decontamination labor, property depreciation rate, investment rate of return).

b. Three problems related to use of the SECPOP2000 code have recently been identified, and publicized throughout the industry. These deal with: (1) a formatting error in the regional economic data block text file generated by SECPOP2000 for input to MACCS2 which results in MACCS2 mis-reading the data, (2) an error associated with the formatting of the COUNTY97.DAT economic database file used by SECPOP2000 which results in SECPOP2000 processing incorrect economic and land use data (e.g., missing entries in the "Notes" column result in data being output for the wrong county), and (3) gaps in the numbered entries in the COUNTY97.DAT economic database file which result in any county beyond county number 955 being handled incorrectly in SECPOP2000. Provide an assessment of the impact of correcting these errors on the VEGP SAMA analysis, including the screening of candidate SAMAs and the final dispositioning of the SAMAs. Provide revised estimates of the maximum averted cost risk (MACR) and the benefits for each SAMA, as appropriate.

c. The population dose risk (PDR) values reported in the table on page F-23 sum to 1.23 person-rem rather than 1.54 person-rem as shown. Furthermore, the total PDR and offsite economic cost risk (OECR) values presented in this table are not consistent with the values used in the Phase II SAMA analysis (Section F.6). Specifically, Section F.4.1 indicates that the baseline off-site population dose risk used was 2.04 person-rem per year, not 1.54 person-rem per year as reported in the table. Also, Section F.4.2 indicates the annual off-site economic risk used was $1,412, not $1,725 as reported in the table. Clarify these discrepancies. If appropriate, provide an updated MACR, modified MACR, and baseline evaluation of the Phase II SAMAs.

d. Describe the method used to project the population within 50-miles of the site for the year 2040, and how the population within the surrounding 28 counties were mapped into the MACCS2 rosettes. Provide the resulting projected population distribution (by sector and radial ring) within the 10-mile radius and the 50-mile radius from VEGP.

e. The 2040 evacuation speed was based on the 2010 evacuation speed and the ratio of the projected population within the Emergency Planning Zone (EPZ) for the years 2010 and 2040. Identify the year 2010 evacuation speed and the year 2010 and year 2040 EPZ populations used to calculate the year 2040 evacuation speed. Describe how the method used to develop the 2010 EPZ population estimate compares with the method used to project the population within 50-miles of the site for the year 2040.

f. The MACCS2 analysis uses a reference pressurized water reactor (PWR) core inventory at end-of-cycle calculated using ORIGEN. The ORIGEN calculations

were based on a 3-year fuel cycle (12 month reload), 3.3 percent enrichment, and three region burnup of 11,000, 22,000, and 33,000 megawatt days per metric ton of uranium (MWd/MTU). Current VEGP fuel management practices use higher enrichments (up to 4.95 percent) and significantly higher fuel burnup (up to 60,000 MWd/MTU discharge burnup). The use of a reference PWR core (scaled only for power) instead of a plant specific cycle could significantly underestimate the inventory of long-lived radionuclides important to population dose (such as Sr-90, Cs-134 and Cs-137), and thus impact the SAMA evaluation. Also, the fission product scaling was based on 3636 megawatt thermal; however, this does not appear to include the proposed VEGP power uprate of 1.7 percent. Provide an assessment of the impact on population dose and on the SAMA screening and dispositioning if the SAMA analysis were based on the fission product inventory for the highest burnup, higher fuel enrichment and higher power level.

g. Tables F.3.1 and F.3.2 provide source term information for each release category.

   i. Table F.3.2 shows that the LERF-steam generator tube rupture (SGTR) plume release of CsI occurs over a ~45 hour period, from 2.7 to 48 hours, with a calculation duration of 48 hours. LATE-SGTR CsI release occurs over only a 4 hour period, from 26 to 30 hours. Describe the phenomenology of CsI release for LERF- SGTR and LATE-SGTR, and the general approach for representing time varying fission product releases as input to the MACCS2 code.

   ii. Table F.3.1 shows a CsI release fraction of 3.8E-01 for a calculation duration of 48 hours for LERF-SGTR (Case 8). Discuss whether the CsI release fraction in Case 8 is limited by the calculation duration and, if so, address the impact on the SAMA results if the calculation duration were extended (e.g., to 120 hours as used in Cases 2a and 3a).

5. Provide the following with regard to the SAMA identification and screening process:

   a. Table A-1 in Attachment F provides a list of 266 SAMAs that had been identified by the nuclear industry in previous license renewal submittals. Section F.5.1 indicates that this list was used as an idea source that was reviewed to determine if a plant enhancement had already been conceived that would address VEGP's needs.

      i. Identify the Phase I SAMAs that were derived from this generic industry list.

      ii. RCP seal LOCAs are one of the largest VEGP risk contributors. SNC identified and evaluated several Phase I SAMAs (SAMAs 1, 2, 6, 7, and 8) to reduce this risk. Table A-1 identifies 24 SAMAs related to RCP seal LOCAs. Several of these SAMAs involve only procedure changes and so should have implementation costs significantly less than some of the Phase I SAMAs that were evaluated. Provide an evaluation of the costs

and benefits of each of the RCP seal LOCA SAMAs in Table A-1 or, alternatively, provide an explanation for why these SAMAs are not applicable at VEGP. Specifically address SAMAs 2, 3, 4, 6, 7, 8, 16, 17, 18, 20, and 21.

iii. SGTR sequences are the dominant contributor to population dose risk and economic cost risk at VEGP. While a number of Phase I SAMAs (SAMAs 2, 4, 10, and 13) were identified and evaluated to reduce the frequency of SGTR sequences, no Phase I SAMAs were specifically identified to reduce the magnitude of releases from SGTR sequences. Table A-1 SAMAs131, 132, 133, 135, and 136 all involve enhancements to reduce the consequences of an SGTR, of which SAMAs 135 and 136 are procedure changes only. Provide an evaluation of these SAMAs, or indicate if the particular SAMA has already been considered. If the latter, indicate whether the SAMA has been implemented or has been determined to not be cost-beneficial at VEGP.

b. Section F.5.1.2.2 indicates that SNC reviewed the Phase II SAMAs from Palisades. Palisades SAMA 23, "Direct PCS cooldown on loss of RCP seal cooling," which involves a procedure change, was determined to be potentially cost-beneficial as Palisades. Provide an evaluation of the costs and benefits of enhancing RCP seal cooldown procedures at VEGP or, alternatively, provide an explanation for why this SAMA is not applicable at VEGP.

c. Section F.5.1.2.2 indicates that SNC reviewed the Phase II SAMAs from Farley. Farley SAMA 166, "Proceduralize local manual operation of auxiliary feedwater when control power is lost" (SAMA 166 in ER Attachment F Table A-1) which involves a procedure change, was determined to be potentially cost-beneficial at Farley. Provide an evaluation of the costs and benefits of implementation of this SAMA at VEGP or, alternatively, provide an explanation for why this SAMA is not applicable at VEGP.

d. Section F.1 states that the Phase I SAMA analysis utilized the following screening criteria: (1) not applicable to the VEGP design or are of low benefit in PWRs, (2) already been implemented at VEGP or whose benefits have been achieved at VEGP using other means, and (3) estimated costs that exceed the possible MACR. All of the Phase I SAMAs in Table F.5-3 that were screened out (e.g., SAMAs 3, 5, and 8) were done so only based on criteria (3). Clarify the statement in the ER regarding the screening process/criteria.

6. Provide the following with regard to the Phase II cost-benefit evaluations:

a. The description of how SAMA 2 was modeled (page F-55) is not sufficient to understand the reasons for the large reduction in CDF, population dose-risk, and OECR for this SAMA. Provide additional detail including assumptions in the base model for failure probability of both the black start diesel generators and the Wilson combustion turbines during SBO events.

b. Describe the PRA model changes made to perform the Phase II evaluation of SAMA 5 for the sensitivity analysis.

c. For a number of the Phase II SAMAs listed in Table F.5-4, the information provided does not sufficiently describe the associated modifications and what is included in the cost estimate. Provide a more detailed description of the modifications and a breakdown of the cost estimate for Phase II SAMAs 1, 6, 7, 9, 12, and 13.

d. With regard to the Phase II evaluation of SAMA 11:

   i. Section F.6.8 says that the potential benefits from SAMA 11 were bounded by assuming that "90 percent of all Loss of [nuclear service cooling water (NSCW)] scenarios were avoided." It also further notes "10 percent likelihood of success is assumed to be representative of a best-case scenario." These statements appear to be contradictory. Provide additional clarification on how SAMA 11 was modeled. Also, provide further justification for the use of the 90 percent and 10 percent assumption and how they impact the SAMA 11 evaluation.

   ii. Section F.6.8 further states that the implementation cost of this SAMA at VEGP is closer to the Farley estimate of $580,000 (actually $520,000 per the Farley ER) than the V.C. Summer estimate of $150,000. Provide a more detailed description of the modifications, breakdown of the cost estimate, and description of the difference between the Farley and V.C. Summer estimates.

   iii. Section F.6.8 further states that the benefit of this SAMA is limited to Loss of NSCW scenarios and would not be effective at eliminating seal LOCAs in SBO scenarios since the power to the hydro pump would be unavailable in the SBO scenarios. Provide an evaluation of an enhancement to this SAMA that includes providing backup power to the hydrostatic test pump.

e. Section F.6.12 provides an estimated implementation cost for SAMA 15 of $900,000. The Wolf Creek Generating Station (Wolf Creek) ER estimated the cost for identical SAMA 1 to be $800,000. The difference is that Wolf Creek assumed the cost of the dedicated diesel generator to be 33 percent less than the $1.2 million estimate originally developed for the advanced boiling water reactor while the VEGP assumed the cost was only 25 percent less. Provide a justification for this change in assumption that resulted in a higher cost.

f. ER page 3.1-1 indicates that the current power level for VEGP is 1232 megawatts electric. ER page F-28 indicates that a power level of 1215 MWe was used in calculating the replacement power cost for the Phase II cost-benefit evaluation. Clarify this discrepancy. Furthermore, ER page 3.1-1 indicates that SNC is submitting a request to NRC for a 1.7 percent power uprate in 2007. Provide justification for the power level used in the Phase II cost-benefit evaluation and an assessment of any changes on the evaluation results.

7. Section F.7.1 identifies SAMA 6 and SAMA 16 as potentially cost-beneficial based on an analysis of the uncertainty of the calculated internal events CDF. Both Section F.7.1.3 and Section F.8 further conclude that these SAMAs are unlikely candidates for realistic consideration at VEGP because of optimistic cost estimates or PRA assumptions. However, the staff does not consider the use of a multiplier of 2.0 to account for uncertainties to be overly conservative since this factor has been reported to be as high as 2.5 for other Westinghouse plants that have submitted license extension applications (e.g., Robinson Steam Electric Plant, Unit No. 2) and as high as 5.0 in NUREG-1560, "Individual Plant Examination Program: Perspectives on Reactor Safety and Plant Performance." Provide additional justification, including engineering/deterministic (versus probabilistic) rationale for why these two SAMAs should not warrant implementation at VEGP. Describe SNC's plans regarding further evaluation of these two SAMAs.

8. For certain SAMAs considered in the ER, there may be lower-cost alternatives that could achieve much of the risk reduction at a lower cost. In this regard, discuss whether any lower-cost alternatives to those Phase II SAMAs considered in the ER, would be viable and potentially cost-beneficial. Evaluate the following SAMAs (found to be potentially cost-beneficial at other plants, and also relevant to the dominant risk contributors at VEGP, or indicate if the particular SAMA has already been considered. If the latter, indicate whether the SAMA has been implemented or has been determined to not be cost-beneficial at VEGP.

   a. Use a portable generator to extend the coping time in loss of alternating current power events (to power selected instrumentation and direct current (DC) power to the turbine-driven auxiliary feedwater pump) (SAMA 167 in ER Attachment F Table A-1).

   b. Provide alternate DC feeds (using a portable generator) to panels supplied only by the DC bus.

   c. Modify emergency procedures to isolate a faulted SG due to a stuck open safety valve (SAMA 135 in ER Attachment F Table A-1). This RAI is related to RAI 5.a.iii.

   d. Provide hardware connections to allow service water to cool network control program seals (SAMA 5 in ER Attachment F Table A-1). This RAI is related to RAI 5.a.ii.

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