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September 24, 2010

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

Subject: Duke Energy Carolinas, LLC (Duke Energy)
Oconee Nuclear Station, Units 1, 2, & 3
Docket Numbers 50-269, 50-270, & 50-287
Generic Letter 2008-01 RAI Response

On January 11, 2008, the NRC issued Generic Letter (GL) 2008-01, Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems. The NRC requested a written response within 9 months of the date of the GL. If the requested response date could not be met, the NRC requested a 3 month response providing a proposed alternative course of action.

By letter dated May 8, 2008, Duke Energy provided an alternative course of action for Oconee as well as Catawba and McGuire. Because some of the system piping referenced in the GL is located in areas inaccessible during power operation (i.e., Containment), the field verifications could not be completed until the upcoming refueling outages. Duke Energy proposed to provide the results of the field verifications to the NRC within 90 days of the end of each refueling outage. By letter dated September 25, 2008, the NRC accepted Duke Energy's alternative course of action.

Duke Energy submitted a three-site response to the GL on October 13, 2008. Oconee also submitted post-outage supplemental responses to NRC on March 2, 2010, March 12, 2009, and August 19, 2009 for Oconee Units 1, 2, and 3, respectively.

On August 25, 2010, NRC submitted a Request for Additional Information (RAI) with regard to the Oconee submittal of October 13, 2008. The response to those RAI questions is attached.

A134

U. S. Nuclear Regulatory Commission
September 24, 2010
Page 2

There are no new commitments contained in this submittal.

Please contact Russ Oakley at (864) 873-3829 if additional questions arise.

I declare under penalty of perjury that the foregoing is true and correct. Executed on
September 24, 2010.

Sincerely,

A handwritten signature in black ink, appearing to be 'Dave Baxter', written in a cursive style.

Dave Baxter, Vice President
Oconee Nuclear Site

Attachment

U. S. Nuclear Regulatory Commission
September 24, 2010
Page 3

cc: w/attachment

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Mr. Andy Sabisch
NRC Senior Resident Inspector
Oconee Nuclear Station

**Attachment
Oconee Units 1, 2, & 3
Generic Letter (GL) 2008-01
RAI Response**

Question 1:

Provide a discussion of the methods used to determine the volume of voids for both venting and ultrasonic testing. Discuss follow up actions such as trending the volume of voids.

Response:

Whenever the system is required to be operable, all volumes are determined by UT prior to and following venting. If any test location provides an indication of a void, the technician measures void arc length, and then measures subsequent void arc lengths every two feet along the pipe run in each direction of the void to determine the length of the void span. Voids in vertical piping are quantified by measuring to the gas/liquid interface.

If a void exceeds acceptance criteria, followup actions would include the following:

- Venting or Dynamic Flushing of the piping is performed until gas is removed or gas void arc length verified to be within procedure limits.
- Void dimensions are documented in the surveillance procedure.
- The Corrective Action Program (CAP) is entered.
- The Senior Reactor Operator and System Engineer are notified.
- Engineering determines void volume using geometric calculations.
- Increased frequency monitoring (such as -next day, -next week, -two weeks, -return to 30 day frequency) is performed to determine if gas intrusion is recurring.
- Technical Specification (TS) Conditions are entered as necessary.
- The Operability / Reportability Determination processes are entered as necessary.
- The cause determination process is entered as necessary.
- Trending of voids is accomplished using the Corrective Action Program. Void acceptance criteria are established at zero in all but three locations (see also response to question 2 below). Any void exceeding the established criteria is entered into the CAP process and the System Engineer is contacted

Question 2:

In Reference 4, the licensee states that "Surveillance procedures have a low threshold for as found gas" and "The Corrective Action Program is entered if the vented volume exceeds a predetermined threshold." Clarify what the threshold volume is, how it was determined, and if it takes into account both water hammers and gas injection limits for pumps.

Response:

Surveillance procedure threshold void volumes are generally established at zero. There are, however, currently three locations across the three Oconee units for which a threshold volume greater than zero has been established. In each case the established acceptance criteria represents a volume that is well below void volumes that would challenge piping or pump operability.

A piping segment at vent valve 1GWD-151 on the 12" Low Pressure Injection (LPI) decay heat drop line establishes an acceptable void arc length of 4 inches which corresponds to a void volume of ≤ 0.04 cubic feet. This void volume exists because of a small captive high point created by a less than ideal location of the vent valve in that segment of horizontal piping. Evaluation of voids in the decay heat drop line takes into account both pump gas ingestion as well as pressure transients when placed in service. An engineering evaluation determined that this captive void potential is insignificant while providing an early threshold for trending.

A piping segment at vent valve 2GWD-153 on the 10" 2A LPI discharge line establishes an acceptable void arc length of 0.5 inch which corresponds to a calculated volume ≤ 0.05 cubic feet. Similar to the previous segment, this void is captive to the vent valve at that location and was characterized as being on the lower limit of detectability. Voids in the LPI discharge piping must take water hammers and flow delivery into consideration. Based on engineering judgment and application of Fauske Technical Paper principles this volume is considered insignificant with respect to water hammer. This volume is likewise considered insignificant with respect to flow delivery.

A piping segment at 2BS-25 on the 8" Building Spray (BS) discharge line establishes an acceptable void arc length of 5.5 inches which corresponds to a void volume of ≤ 0.2 cubic feet. Voids in the BS discharge line must consider water hammers and flow delivery. Voids in this piping section were evaluated by engineering calculation using the Fauske (FAI/08-70 Rev. 0) Technical Paper to estimate the peak pressure pulses, then using these loads for evaluation of piping and hanger stress analysis. An evaluation of effect on flow delivery determined that this volume would be insignificant. The acceptance void limit of 0.2 cu. ft. is $< 15\%$ of the void evaluated in calculation OSC-9592 and provides an early threshold for trending.

Question 3:

In Reference 4, the licensee states that “the consequences of the gas were evaluated to be acceptable.” Please provide a brief description of the criteria and methodology used to determine acceptability.

Response:

The information provided below discusses methods utilized in support of the GL nine-month response. Duke Energy intends to continue to follow industry efforts towards method improvement, and intends to apply new or improved methods as appropriate going forward.

Voids identified during the confirmatory UT inspections that could not be vented on-line were evaluated as follows:

For each of the voids listed below, follow-up UT inspections verified that the void sizes were not increasing. Each of these locations was targeted as program sites for monitoring.

- The following voids, located in LPI discharge piping, were evaluated for their potential to cause water hammers and to impact the delivery of water by increasing the delay in achieving full flow. The volumes of these gas pockets were considered inconsequential in size; therefore, based on engineering judgment and application of Fauske Technical Paper principles, the water hammer and flow delay impacts were deemed to be inconsequential.
 - Downstream of 3LP-17, a void estimated to be 0.002 cu.ft. (10 in. pipe)
 - Downstream of 2LP-17, a void estimated to be 0.0004 cu.ft. (10 in. pipe)
- The following voids, located in Building Spray discharge piping, were evaluated for their potential to cause water hammers and to impact the delivery of water by increasing the delay in achieving full flow:
 - Upstream of 1BS-2, a void estimated to be 0.1 cu.ft. (8 in. pipe)
 - Upstream of 2BS-2, voids estimated to be 1.8 cu.ft. (8 in. pipe)
 - Upstream of 3BS-2, voids estimated to be 1.7 cu.ft. (8 in. pipe)

The volumes of these gas pockets were evaluated by engineering calculation OSC-9592 using the Fauske (FAI/08-70 Rev. 0) Technical Paper to estimate the peak pressure pulses, then using these loads for evaluation of piping and hanger stress analysis. The impact of an assumed void of 2.5 cu.ft. on the delay in delivery of water was determined to be inconsequential when factored into existing engineering calculation.

- A void located in LPI discharge piping downstream of 1LP-17 (estimated to be 0.13 cu. ft. in a 10-inch pipe) was evaluated for the potential to cause water hammer or to impact the delivery of water by increasing the delay in achieving full flow. The volume of this

gas pocket was evaluated by comparison to the engineering calculation OSC-9592 discussed above to conservatively estimate a peak pressure pulse, then using that load to evaluate piping and hanger stress analysis. Per engineering judgment, any increase in flow delay due to this void was deemed insignificant in any event.

- A void located in the LPI Decay Heat drop line (estimated to be 0.015 cu. ft. in a 12-inch pipe) downstream of 1LP-3 near vent valve 1GWD-151 was evaluated for the potential to cause pump damage or gas binding. The evaluation methodology considered the following:
 - gas volumes as the average cross sectional percentage over the length of the potential void section,
 - elevation drops and piping bends to ensure the two phase mixture entering the pump is a bubbly mix,
 - pump vendor documentation regarding capability to ingest gas on a continuous or short duration basis, and
 - flow velocities related to bubble transport potential and ingestion durations.

Question 4:

In Reference 4, the licensee states that “Approximately 20 new vent valves will be needed on each unit.” What is the status of these valves? Please justify any cancellations of installation.

Response:

During the most recent (spring 2010) Unit 2 Refueling Outage the installation of all new vent valves was completed. No vent locations were cancelled.

During the upcoming (fall 2010) Unit 3 Refueling Outage the installation of all new vent valves with the exception of 1 location on the Building Spray System are planned. No vent locations have been cancelled.

During the next (spring 2011) upcoming Unit 1 Refueling Outage the installation of all new vent valves are planned. No vent locations have been cancelled.

Question 5:

In Reference 4, the licensee states that “Effective transport velocities when dynamic venting is credited (Froude number of > 0.55 for horizontal piping runs and > 1.0 for vertical piping runs).” Justify that dynamic venting under these conditions is able to remove voids.

Response:

The criteria used was derived from WCAP-16631-NP Vol. 1. From Section 3.3.1:

Since most of the available literature correlates air transport out of horizontal pipes on the basis of Froude number (NFR), this is expected to be the primary correlating parameter. Based on the current state of knowledge, the following transport characteristics can be expected:

- *For $NFR < 0.35$ no air will be transported downwards towards the pump suction.*
- *For $NFR > 0.55$ all of the air can be flushed out of a horizontal pipe into a plenum. The ability to transfer air through a piping system depends on the layout of piping downstream of the horizontal local high point. It is reasonable to expect that $NFR=0.55$ will not be sufficient to purge all of the air out of the local high point.*
- *For $NFR > 1.0$ all of the air will be transported downwards towards the pump suction.*
- *For $0.35 < NFR < 1.0$ at least a portion of the air can be expected to be discharged from the local highpoint.*
- *The rate of air entrainment is expected to be a function of the Froude number (NFR) in the horizontal pipe.*

Additionally these values were consistently discussed and demonstrated at the industry meetings associated with this GL as reliable thresholds for dynamic flushing. As part of the licensee activities related to the Generic Letter evaluations, confirmatory UTs were performed at numerous locations to evaluate the effectiveness of dynamic venting. It is recognized that dynamic flushing requires an element of time to ensure gas is completely moved out of the piping. It is also recognized that gas may be removed from piping at lower Froude numbers if given sufficient duration. As ongoing validation, Post Dynamic Flush UTs and/or Program Monitoring UTs are conducted at numerous points on the subject systems to verify the dynamically flushed piping remains sufficiently full.

Question 6:

Describe the monitoring of appropriate plant parameters during normal and shutdown operation, including reduced inventory and mid-loop operation, such as monitoring level indicators, including the level of the volume control tank and accumulator and piping pressures. Clarify how often the accumulator water make-ups and water make-up rates are monitored and trended as part of the Engineering Support Program. For reduced inventory and mid-loop operations justify that the water level is sufficient to prevent vortexing due to suction from the residual heat removal system.

Response:

Normal Operation Monitoring

Letdown Storage Tank (LDST) Monitoring

LDST level and pressure are indicated on local gages, on the main control boards, and on the Operator Aid Computer (OAC). Statalarms and OAC alarms are provided to immediately alert operators to high or low LDST level and/or pressure. Also, an OAC alarm is provided to notify operators of a channel mismatch between the two level indicators.

LDST level and, pressure indications are visually checked on each shift and a channel check between the redundant level indicators provided on the main control board is also performed by operators once per shift. Valves 1,2,3HP-24 and 1,2,3HP-25 open on Engineered Safeguards channels 1 and 2 (respectively) actuation and are also interlocked to open at any time should the LDST level drop to the low level alarm setpoint to provide a suction source for the High Pressure Injection (HPI) pumps from the Unit's Borated Water Storage Tank (BWST). Per engineering calculations, the LDST low level alarm setpoint ensures no vortexing or gas entrainment.

Core Flood Tank (CFT) Monitoring

CFT level and pressure for both CFTs are indicated on the main control boards and on the OAC. Statalarms and OAC alarms are provided to immediately alert operators to high or low CFT levels and/or pressures. CFT level and pressure indications are visually checked on each shift and a channel check between the redundant level indicators for each CFT provided on the main control board is also performed by operators once per shift.

Operators ensure CFT levels, pressures, and boron concentrations are all within specification prior to pressurizing the RCS above 800 psig. While the Unit is online, the only reduction in CFT level expected is due to required monthly sampling. The Core Flood (CF) System Engineering Support Document (ESD) currently specifies weekly monitoring of CFT level trends by the CF system engineer. This monitoring is currently credited for detecting CF/LPI valve leakage inside containment which could lead to degassing conditions and gas void formation in LPI piping inside containment. The ESD directs entry into the CAP if leakage is detected by this trending. As technologies and techniques advance, other methods of monitoring for CF/LPI valve leakage inside containment and/or gas void formation in LPI piping inside containment may be used to

reduce or eliminate the dependence on the ESD directed monitoring (including changes to the frequency of monitoring as directed by the ESD). Also, the monthly ultrasonic (UT) monitoring program monitors high points in the Auxiliary Building upstream of the normally closed LPI header isolation valves (1,2,3LP-17 and 1,2,3LP-18). This monitoring would detect any degassing across the normally closed LPI header isolation valves due to leakage from the CFTs. The controlling procedures for this monitoring direct entry into the CAP if any measured void exceeds location-specific acceptance criteria.

Shutdown Monitoring

Per Duke Energy Nuclear System Directive (NSD) 403, Reduced Inventory for Oconee is defined as RCS level less than 50 inches above centerline of the reactor vessel hot leg with fuel in the reactor vessel and mid-loop operation is defined as RCS level lower than the top of the RCS hot leg piping at the reactor vessel junction with fuel in the core (approximately 18 inches above the centerline of the reactor vessel hot leg piping). Oconee Selected Licensee Commitment (SLC) 16.5.3 has the following requirements (with respect to level indication) for draining the RCS to less than 50 inches above the centerline of the reactor vessel hot leg with irradiated fuel in the reactor vessel:

- At least one channel of the reactor vessel level indication system, either LT-5A or LT-5B shall be available and operable
- At least one channel of the ultrasonic reactor vessel level detection system, either Hot Leg or Cold Leg, or other backup level indicating system, shall be available and operable in addition to LT-5A or LT-5B

The above requirements are implemented in procedure OP/*A/1103/011 (Draining and Nitrogen Purging RCS), which contains further (more restrictive) guidance to preclude loss of decay heat removal (DHR) during RCS draining evolutions. The procedure requires four level indicators to be available when draining the RCS to less than 100 inches level (two channels of reactor vessel level indication system, two channels of ultrasonic reactor vessel level detection system). Also, the RCS shall not be drained to less than the 10 inch level with fuel in the core. Per engineering calculations, the 10 inch level limit ensures no vortexing at the DHR drop line nozzle or gas entrainment into the LPI system. The setpoint provides allowance for instrument uncertainty. Operators monitor reactor vessel level hourly while an Oconee Unit is in Mode 6 or while RCS level is in a Reduced Inventory condition. In addition to Operator hourly monitoring, the OAC provides continuous monitoring and alarms for the two trains of the reactor vessel level indication system and the two trains of the reactor vessel level detection system.

Question 7:

Training was not identified in the GL (Reference 3) but is considered to be a necessary part of applying procedures and other activities when addressing the issues identified in GL 2008-01. Provide a brief description of training.

Response:

Oconee has provided both initial and continuing training to key target groups on site covering the topic of gas intrusion into plant systems. The target groups are Engineering; Operations, Chemistry, and Maintenance. The training includes coverage of both INPO SER 02-05 and GL 2008-01. A brief description of that training is provided below.

Engineering

“Just In Time Training” was provided to system engineers performing gas intrusion evaluations for their systems. This training was completed on 3/31/09. This training covered INPO SER 02-05, Rev. 1 for systems beyond the scope of GL 2008-01. It included discussion of potential gas sources and potential accumulation locations, as well as recommended techniques for performing system evaluations.

Training on SER 02-05 and GL 2008-01 was provided as part of the first cycle of Engineering Continuing Training in the first trimester of 2009. These topics have also been placed on the “backbone” schedule to review annually. (The backbone schedule is a four-year plan describing continuing training requirements for a program.) Training included the following elements:

- discussion of gas intrusion events and their consequences
- causal factors and conditions for gas intrusion (design characteristics, operating practices, equipment performance problems, etc)
- plant-specific actions and strategies for identification, prevention, and mitigation of gas intrusion

Second trimester 2010 Engineering Continuing Training also includes an HPI system training module which will cover gas intrusion issues specific to the HPI system. This training will address the 1997 Oconee HPI gas intrusion event and also discuss safety implications of inadequate gas control, sources of gas, potential accumulation locations, and actions taken to address GL 2008-01 concerns for HPI, LPI, and BS systems.

Operations

Operations Training lesson plan on SOER 97-01 was presented to Operations personnel in classroom training during fourth quarter of 2008. The lesson plan was updated to include industry events which occurred since issuance of SOER 97-01. This update included safety systems other than those originally discussed in SOER 97-01, including containment spray,

auxiliary feedwater, high pressure coolant injection, reactor core isolation cooling, and residual heat removal/low pressure safety injection. The training included discussion of the consequences of gas intrusion on safety system operability, water hammers, pump trips, high pump vibration, pump damage, and abnormal system flows. The updated training addressed both pressurized water reactors and boiling water reactors. The updated training included information from INPO SER 02-05 (March 2005) and Rev. 1 (Jan. 2008), and addressed the Oconee event of 2/22/97. In early 2009, Operations lesson plans were revised to include more focus on SER 02-05 and GL 2008-01 issues for both initial and continuing training.

Chemistry

SER 02-05 Rev. 1 was presented in the 2008 and 2009 fall Chemistry Operating Experience continuing training class. The training provided to Chemistry was very similar in content to that provided to Engineering, and included emphasis on GL 2008-01. Cause and consequence of gas intrusion events as well as sources and processes for gas intrusion were identified and discussed. SER 02-05 was also added to the backbone schedule to evaluate annually. In 2009, SOER 97-01 was added to the HPI lesson plan for two-week systems training provided to all Chemistry technicians.

Maintenance

In 2009, SOER 97-01 was added to the HPI lesson plan for two-week systems training provided to all Maintenance technicians. SOER 97-01 and SER 02-05 were added to the backbone schedule to evaluate annually and will be taught every four years at a minimum.

Maintenance training (OCM-648) included cause and consequences of gas intrusion events. Sources and processes for gas intrusion were identified and discussed. The following maintenance activities were identified that could affect gas intrusion into systems:

- Incorrect installation of tubing fittings
- Substandard valve repair
- Incorrect setting/calibration of volume control instrumentation
- Procedure non-compliance
- Inadvertent equipment actuation that could lead to absorption, desorption, and gas stripping

Industry operating experience (including Oconee events) and maintenance-specific operating experience of leaking valves causing gas intrusion were also addressed.

All Maintenance technicians receive initial training in tube fitting removal and replacement. Instrumentation and Controls technicians also receive training on tubing and compression fittings and level measurements.



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