February 6, 2006

Mr. J. A. Stall
Senior Vice President, Nuclear and
Chief Nuclear Officer
Florida Power and Light Company
P.O. Box 14000
Juno Beach, Florida 33408-0420

SUBJECT: ST. LUCIE NUCLEAR PLANT, UNIT 2 - REQUEST FOR ADDITIONAL INFORMATION REGARDING PROPOSED AMENDMENT FOR REDUCED REACTOR COOLANT SYSTEM FLOW (TAC NO. MC8757)

Dear Mr. Stall:

By letter dated October 21, 2005, Florida Power and Light (FPL) submitted a proposed license amendment to reduce reactor coolant system flow with a reduction in reactor operating power at St. Lucie Unit 2.

The U.S. Nuclear Regulatory Commission staff has reviewed your submittal and finds that the additional information contained in the enclosed Request for Additional Information is needed before we can complete the review. This was discussed with members of the FPL staff and, on January 31, 2006, Mr. Ken Frehafer indicated that a response would be provided by February 28, 2006.

If you have any questions, please contact me at (301) 415-3974.

Sincerely,

/RA/

Brendan T. Moroney, Project Manager
Plant Licensing Branch II-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-389

Enclosure: Request for Additional Information

cc w/encl: See next page

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REQUEST FOR ADDITIONAL INFORMATION

FLORIDA POWER AND LIGHT COMPANY

ST. LUCIE NUCLEAR POWER PLANT, UNIT 2

DOCKET NUMBER 50-389

1. General:

a. Technical Specification (TS) 3.7.1.1 allows operation at reduced power levels with inoperable main steam safety valves (MSSVs).

i. Discuss the validation of these operational modes at the 42-percent steam generator tube plugging (SGTP) operating condition.

ii. Discuss whether the safety analyses supporting the 42-percent SGTP at 89 percent power conditions have assumed inoperable MSSVs as an initial condition or not.

b. The Updated Final Safety Analysis (UFSAR) Chapter 15 safety analyses are initiated at nominal operating condition (e.g., T_{inlet}, feedwater temperature, SG pressure, SG liquid inventory, etc.) with the monitoring uncertainties accounted for either directly or via the Revised Thermal Design Process. With respect to the uncertainty associated with the actual nominal operating conditions following start-up (due to unknown SG plugging, reactor coolant system (RCS) flow rate, etc.), explain how the initial conditions assumed in the safety analyses will be validated.

Note: In the following questions, all figures, section numbers and page numbers refer to Westinghouse document WCAP-16489, "St. Lucie Unit 2 42-Percent Steam Generator Tube Plugging - Licensing Report," dated October 2005.

2. Safety Analysis Reactor Protection System (RPS) and Engineered Safety Feature Actuation System (ESFAS) Setpoints - Pressure Measurement Uncertainty

Table 5.1.0-4 (Sheet 1 of 2) indicates that the difference between the analysis value and the TS value is 40 pounds per square inch (psi) for the setpoint of a low SG pressure trip, and setpoints for the Main Steam Isolation System and Main Feedwater Isolation System. The value of 40 psi is less than the pressure measurement uncertainty of 45 psi as indicated on page 5-2. Justify that the difference of 40 psi between these analysis setpoints and TS values are acceptable to represent an allowance for steady-state fluctuation and pressure measurement error of 45 psi.

3. Safety Analysis RPS and ESFAS Setpoints - Basis for a Lower Analysis Setpoint

Table 5.1.0-4 (Sheet 1 of 2) indicates that the setpoint of variable power level-ceiling used in the analysis is 102 percent of the rated thermal power (RTP), while the setpoint specified in TSs is 107 percent of the RTP. Using a lower power setpoint in the analysis will cause an earlier reactor trip, which may result in a lower peak RCS pressure and higher Departure from Nucleate Boiling Ratios (DNBRs) during transients. Hence, the assumed lower power trip

setpoint may be nonconservative. Provide the value of the normal setpoint (in both percent of RTP and megawatts thermal) and demonstrate the adequacy of using the lower power trip setpoint rather than the TS value in the analysis.

4. Increased Feedwater Flow Event - Need for Inclusion of a TS Limiting Condition for Operation (LCO)

Table 15.1.1-2 indicates that during the increased feedwater flow event, the high-high SG water level trip signal trips the reactor and closes feedwater isolation valves, preventing the SG from overfilling with water.

In the case where feedwater isolation valves fail to close due to the single failure consideration, identify the equipment that can be used to isolate feedwater and avoid SG overfilling with water, and discuss the reliability of that equipment for feedwater isolation. Also, address the compliance with Criterion 3 of Title10 of the *Code of Federal Regulations* (10 CFR), Part 50, Section 36, which requires inclusion of a LCO for a structure, system, or component that is used to mitigate the consequences of a design basis event.

5. Increased Feedwater Flow Event at Power - Causes for Temperature Changes

Figure 5.1.1-5 shows the core average moderator temperature during an increased feedwater flow event at power. The figure shows that the temperature decreased rapidly after a reactor trip at 124 seconds. During the period 133 to 138 seconds into the transient, the temperature increases by about 10 degrees Farenheit followed by a decrease in temperature.

Explain the causes for the temperature increase from 133 to 138 seconds and the temperature decease from 138 to 145 seconds.

6. Pre-Trip Main Steam Line Break (MSLB) - DNB Propagation

UFSAR Section 15.1.5.4 concludes that less than 2.5 percent of the rods experience DNB. Further, the UFSAR states, “. . . DNB propagation will not lead to more rod failures than those calculated due to DNB for this event. . . . . DNB propagation is not postulated to occur.” Demonstrate that DNB propagation does not occur for the 42-percent SGTP analysis.

7. Post-Trip MSLB - Effect of a Lower RCS Flow on the DNBR Calculation

A specific 42 percent SGTP RETRAN simulation was not done and the post-trip MSLB T_{mdnbr} statepoints were based upon the 30 percent SGTP analysis statepoints.

a. Demonstrate that the use of these statepoints, adjusted only for the reduced flow rate (335,000 gallons per minute (gpm) to 300,000 gpm), are conservative with respect to the ANC core physics calculation.

b. Discuss the slight improvement in calculated minimum DNBR in light of the reduction in RCS flow rate.

8. Feedwater Line Break (FWLB) - Event Classification and Associated Acceptance Criteria

UFSAR Section 15.2.8.5 states: “With respect to the DNB design basis, the feedwater line break event is bounded by the pre-trip steam line break event.” Whereas, Section 5.1.12.4 of the 42 percent SGTP license amendment concludes that the FWLB DNB degradation is bounded by the complete loss of flow (LOF) event. Discuss this change in licensing strategy. In your discussion, address the difference in event classification (e.g., LOF Condition II, MSLB/FWLB Condition III/IV depending on break size) and any difference in allowed radiological consequences (MSLB within 10 CFR Part 100, FWLB small fraction of 10 CFR Part 100 guidelines).

9. Loss of Normal Feedwater Flow Event - SG Blowdown Flow Effect

Item II.D of Standard Review Plan 15.2.7 indicates that an acceptable analysis of the loss of normal feedwater event should comply with requirements of the Three Mile Island action plan, Item II.E.1.2 as it relates to the performance requirements of the auxiliary feedwater system for long-term cooling (LTC) during a loss of normal feedwater event. Recently, the licensee of a Combustion Engineering (CE) plant indicated that its analysis addressing the II.E.1.2 requirements did not consider the effect of SG blowdown flow, resulting in a lower required auxiliary feedwater flow for LTC during a loss of normal feedwater event - the limiting event of the decreased heat removal by the secondary system.

Since St. Lucie Unit 2 is a CE plant, please provide the following information to assure that the SG blowdown flow is adequately considered in the required analysis:

a. Specify the values of the flow rate of the SG blowdown system during normal and high blowdown flow operating conditions.

b. List the actuation signals and the associated setpoints that isolate the SG blowdown system, and discuss the design basis events used to determine the setpoints for SG blowdown system isolation.

c. Describe the model of the SG blowdown system in the system code (CESEC or RETRAN, as applicable) used to demonstrate the compliance with the II.E.1.2 requirements, and justify that the SG blowdown model adequately reflects the SG blowdown flow and its isolation as designed, and required operator actions consistent with appropriate operating procedures.

10. Loss of Condenser Vacuum Event - Basis for Power Operated Relief Valve (PORV) Actuation Assumed in the Analysis

The third paragraph on page 5-92 states that for the loss of condenser vacuum event addressing the adequacy of the capacity of the main steam safety valves, “the PORVs are modeled with one valve aligned to the pressurizer and one valve locked out. The PORVs are activated . . . to protect the PSVs [pressurizer safety valves] against spurious actuation by limiting pressure increase post-trip.”

Confirm that the PORVs are a safety grade system, or justify that they are adequate for use in accident mitigation.

11. Asymmetric SG Transient - Limiting Cases

Section 5.1.11 documents the results of the analysis of the limiting asymmetric SG transient - an inadvertent closure of the main steamline isolation valve to one SG. Paragraph 2 on page 5-107 indicates that for the limiting cases analysis, two cases were analyzed: one assuming 0 percent of SG tubes to be plugged and one assuming 42 percent of the SG tubes to be plugged. It further states that these cases will cover any asymmetry within these limits.

Provide information to show that the results of the two analyzed cases bound the following asymmetric cases in terms of a greatest challenge to the DNB design basis:

a. the isolated SG with a 42 percent SGTP and the unisolated SG with no SGTP, and

b. the isolated SG with no SGTP and the unisolated SG with a 42 percent SGTP.

12. Locked Rotor Event - Effect of Asymmetric SGTP on the DNB Analysis

Paragraph 4 on page 5-159 indicates that the effect of a flow asymmetry resulting from asymmetric tube plugging is addressed in the DNB analysis of the locked rotor statepoints.

Discuss the cases analyzed, the associated initial conditions and analytical results to show the effect of an asymmetric SGTP on the analysis of the locked rotor event.

13. Small Break LOCA - Air in the High Pressure Safety Injection (HPSI) System

a. At another CE facility, it was discovered that the containment pressure during the recovery from a small break LOCA might be significantly lower than originally assumed. At the lower pressure, at the time when the HPSI pumps would switch suction to the containment sump, the HPSI pumps might continue to take water from the refueling water tank (RWT) as the isolation valve closed. As a result of the continued flow, the level in the refueling water tank might drop sufficiently such that air would be ingested into the HPSI pumps from vortexing. Plugging of SG tubes will affect the energy released to the containment during a small break LOCA and will affect the containment pressure. Provide an analysis of containment pressure following a small break LOCA and an analysis of refueling tank level to demonstrate that air will not be ingested into the HPSI pumps following switchover of suction to the containment sump.

b. In Section 5.2.4.1 it is stated that the safety injection tanks are assumed not to inject in the analysis of small break LOCA. This would be conservative for the purpose of calculating core performance, but would not be conservative for calculating minimum containment pressure. In your evaluation of containment pressure following a small break LOCA as requested above, please include the effect of safety injection tank injection. Similarly, it is stated that failure of an emergency diesel is the most limiting single failure. In calculating the minimum containment pressure during the time of switchover for the purpose of

determining flow from the RWT and from the containment sump, justify that assumptions resulting in the minimum containment pressure were used.

14. Post-LOCA LTC - Mixing Volumes Used in the Boron Precipitation Analysis

Section 5.2.5.1 describes the assumptions used in the boric acid precipitation analysis. It is stated the BORON computer code uses a constant, input-specified value for the mixing volume that is conservatively determined. It is further stated that the mixing volume consists of 50 percent of the volume of the lower plenum and liquid volumes for the core and the outlet plenum up to the elevation of the bottom of the hot legs based on CEFLASH-4AS calculations.

a. Provide values of the contribution to the mixing volume from the lower plenum, core and upper plenum used in the BORON code analysis.

b. Justify that the mixing volume contributions from the core and upper plenum were conservatively selected from the CEFLASH-4AS analysis. Higher values of decay heat encountered early in the accident will lead to higher core voiding, whereas lower containment pressure encountered later in the accident will also lead to higher core voiding.

c. It is stated that for the outlet plenum the core-to-outlet plenum area ratio was applied to the core exit void fraction that was calculated by CEFLASH-4AS. Justify that this approach is conservative for calculating the mixing volume.

d. Justify that 50 percent of the lower plenum volume will mix with the fluid in the core during long term cooling so as to be appropriately included in the mixing volume.

e. Discuss how the volume of the core bypass region was treated in the core boron concentration calculation. Describe how the void fraction of the core bypass region was determined.

15. Boron Precipitation - Boron Injection from the RWT, HPSI Pumps, Containment Sump

Section 5.2.5.1 states that the Boric Acid Makeup Tank injection is assumed to be mixed with the safety injection flow from the RWT and then flows to the mixing volume with the excess spilling into the containment sump.

a. Provide, as a function of time, the concentration of boric acid that flows to the mixing volume during the time that injection is from the RWT and during the period when the HPSI pumps take suction from the containment sump. This data should extend to the time when the maximum boric acid concentration in the core is determined to occur.

b. Describe how boric acid concentration in the containment sump is calculated. Discuss what water sources are included and what the boric acid concentration is from each source. Justify that these values are conservative.

16. Boron Precipitation - Noding Detail and Assumptions Used in the BORON Code

Figures 5.2.5.3-2a and 5.2.5.3-2b are plots of long term boric concentration in the core as a function of time. Concentration of boric acid in the core during post-LOCA long term cooling will be greater at the top of the core as a result of boiling up the core channel. Boric acid concentrations at the top the core will be reduced by reactor vessel internal circulation.

a. What core locations are represented by figures 5.2.5.3-2a and 5.2.5.3-2b?

b. Discuss the noding detail used to model the core in the BORON code and justify that the noding is adequate to conservatively model the boric acid concentration at the top of the core.

c. Provide and justify assumptions in the BORON code for any internal reactor vessel circulation assumed in the analysis.

17. Boron Precipitation - Values of Key RCS Parameters

To enable the NRC staff to perform a confirmatory analysis of boric acid concentration in the core following a large break LOCA at a reactor coolant pump discharge, please provide the following information:

a. Volumes and heights of the lower plenum, core, core bypass and upper plenum.

b. Height of the bottom elevation of the hot leg above the top of the active core.

c. Volume and height of the downcomer to the bottom elevation of the cold leg, bottom elevation of the downcomer and bottom elevation of the lower head.

d. Loop resistance from the upper plenum at the hot leg centerline through the SGs to the top of the downcomer at the cold leg centerline. Provide the friction and geometric K-factors, including the mass flow rates, flow areas and specific volumes that the K-factors are based on. (The station-to-station pressure drop information for the loop which is used for initializing the CEFLASH-4AS code contains the appropriate information.) Also, provide the reactor coolant pump locked rotor K-factor.

e. Minimum temperature of the RWT. Please include the sump temperature vs. time following recirculation actuation.

f. Boron concentration of the safety injection tanks, RWT and boric acid storage tanks. The capacity of the tanks is also needed.

g. Elevation of the bottom of the loop seal piping (suction leg) and bottom elevation of the cold leg.

18. Post-LOCA LTC - Steam Entrainment

Table 5.2.5.3-1 indicates that HPSI water that is injected into the hot legs will not be entrained by steam exiting the core and traveling to the break for times greater than 2 hours post-LOCA. Provide any experimental data or calculations that support this conclusion.

19. Post -LOCA LTC - Auxiliary Feedwater Sources

Section 5.2.5.3 states that at 16 hours post-LOCA the operational staff will decide whether to maintain core cooling using the shutdown cooling system or to maintain core cooling by simultaneous hot and cold leg HPSI injection. Provide justification that a sufficient source of safety-related auxiliary feedwater will be available to support the 16-hour decision time.

20. Primary Line Break Outside Containment

Please revise Section 5.1.23.4 to reflect the proposed operating conditions of maximum power of 89 percent of rated thermal power, minimum RCS flow of 300,000 gpm and SGTP level of 42 percent. Specifically, justify that the analysis of record is still a limiting case in terms of the changes in RCS inlet and outlet temperatures, pressurizer conditions and operating power.

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