June 21, 2004

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 PLANT, UNIT 2 - REQUEST FOR ADDITIONAL INFORMATION REGARDING PROPOSED LICENSE AMENDMENT, WCAP-9272 RELOAD METHODOLOGY AND IMPLEMENTING 30% STEAM GENERATOR TUBE PLUGGING LIMIT (TAC NO: MC1566).

Dear Mr. Stall:

By letter dated December 2, 2003, Florida Power and Light Company submitted an amendment request to allow operation of St. Lucie Unit 2 with a reduced reactor coolant system flow, corresponding to a steam generator tube plugging level of 30% per steam generator.

The U. S. Nuclear Regulatory Commission (NRC) staff has reviewed your submittals and finds that a response to the enclosed request for additional information (RAI) is needed before we can complete the review. Based on the discussion with Mr. George Madden of your staff, this RAI will be discussed with members of your staff in a meeting at the NRC Headquarters. The actual date of the meeting will be set once your staff has had adequate time to review the RAI.

If you have any questions, please feel free to contact me at 301-415-3974.

Sincerely,

/RA/

Brendan T. Moroney, Project Manager, Section 2
Project Directorate II
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket No.: 50-389

Enclosure: As stated

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. The Technical Specification (TS) plugging limit for steam generator tubes (typically 40% of the nominal tube wall thickness) is based on minimum tube wall thickness requirements necessary to ensure that stress limits will be maintained within design basis limits for the spectrum of normal operating and accident conditions with allowance for incremental flaw growth between inspections and flaw measurement error. The analyses to determine these minimum wall thickness requirements in support of the TS plugging limit are usually referred to as "Regulatory Guide (RG) 1.121 analyses." (RG 1.121 is entitled, "Bases for Plugging Degraded PWR Steam Generator Tubes"). What impact does the subject license amendment request have on the loads, including differential pressure loads, vibrational loads, and temperatures acting on the tubes during normal operating and accident conditions? What is the impact of these revised loadings on the minimum wall thickness requirements? If there is an impact, discuss whether the technical specification 40% plugging limit continues to provide adequate allowance relative to the minimum wall thickness requirements for incremental flaw growth between inspections and flaw measurement error.

2. What design bases parameters, assumptions or methodologies (other than those provided in the December 2, 2003 submittal) were changed in the radiological design basis accident analyses as a result of the proposed change? If there are many changes it would be helpful to compare and contrast them in a table. Also, please provide a justification for any changes.

3. Section 4.6 of Reference 2, states that the methodology and analysis assumptions presented in L-2003-220 (dated September 18, 2003, "Alternate Source Term Methodology and Conforming Amendments") remain applicable to the 30% Steam Generator Tube Plugging (SGTP) analysis. What radiological dose consequence analysis parameters are impacted by the proposed change? Please provide the value of the parameters impacted and justification why the methodology and assumptions in L-2003-220 are not impacted.

4. Section 4.6 of Reference 2, states the dose calculations for the Steam Generator Tube Rupture (SGTR) are redone using the same methods and assumptions (as L-2003-220) except for the steam release information from the two steam generators. What is the reactor coolant system mass assumed for each accident described in Section 4.6?

5. L-2003-220 contains the parameters and assumptions used for the calculation of the SGTR accident. For the SGTP amendment please provide the same information as contained in Tables 2.4-1 through Table 2.4-5 of L-2003-220. Please specify the break flow flashing fraction and the break flow mass in the ruptured steam generator.

Enclosure

6. Nuclear Design

   a. Section 3.1 of Reference 3 indicates that the Westinghouse nuclear design models and methods are used for the St. Lucie Unit 2 nuclear design. Justify that the Westinghouse methods, documented in WCAP-11569 for PHOENIX-P/ANC, WCAP-10965 for ANC and WCAP-10216 for the relaxation of control axial offset control, are applicable for use in the nuclear design for St. Lucie Unit 2 including the Combustion Engineering (CE) fuel design with ZIRLO cladding.

   b. Please provide verification (documentation, such as a SE) that the Westinghouse Relaxed Axial Offset Control (RAOC) Methodology, was also approved for non-Westinghouse plants.

   c. Standard Westinghouse nuclear design models and methods were approved for applicability to the Westinghouse plants only. No non-Westinghouse plant data was provided with the Westinghouse nuclear design analytical models and methods. Consequently, these nuclear models cannot be applied to non-Westinghouse plants. Please provide quantitative technical justification (pertinent non-Westinghouse data) in support of validating the RAOC methodology for non-Westinghouse plants.

   d. In Section 3.4, reference is made to “baseline neutronics”; “adjusted only slightly”; “preclude violations”, resulting in challenges to analysis margins. What do these mean?

   e. Table 3-1 provides the key safety parameters ranges, but no technical basis is provided to support the changes, particularly, the increase in the Moderator Temperature Coefficient (MTC) from the current value of +3 to +5 up to 70% power. Please provide quantitative and qualitative bases for this change.

   f. The first paragraph on page 3-3 does not adequately discuss the six bullets provided in Section 3.6. Please provide detailed quantitative and qualitative technical justification for each one of these bullets, in particular, the subject of non-linear relationship for axial flux and the elimination of the positive MTC. What is a part power multiplier?

7. Thermal-Hydraulic Design

   a. Section 4.2 of Reference 3 indicates that the W-3 correlation and the standard thermal design procedure are used to calculate Departure from Nucleate Boiling Ratios (DNBRs) when the ABB-NV DNB correlation and revised thermal design procedure are not applicable. Identify the non-LOCA events that use the W-3 correlation in the DNBR analysis, and discuss the computer code with the W-3 correlation used for the core thermal-hydraulic analysis. Justify that the W-3 correlation and the associated DNBR safety limit are acceptable for the St. Lucie Unit 2 DNBR calculations.

8. Non-LOCA Transients

a. Section 5.1 of Reference 3 indicates that the WCAP-9272 methodology is used for the St. Lucie Unit 2 reload analysis. WCAP-9272 identifies for each design basis event the key safety parameters and their limiting directions that result in a minimum margin to the applicable safety limits. Please compare the values of the key safety parameters assumed in the St. Lucie Unit 2 reload analysis with those limiting directions specified in WCAP-9272 for each event analyzed. Identity and justify the differences in the limiting directions of safety parameters assumed in the St. Lucie Unit 2 reload analysis.

b. List the single failure events that are considered in the St. Lucie Unit 2 reload analysis. Identify the limiting single failure and provide the rationale for determination of the limiting single failure for each analyzed event.

c. Provide values of opening setpoints of pressurizer safety and main steam safety valves that are credited in the reload analysis. Discuss the determination of the valves' lifting setpoints with inclusion of the positive or negative uncertainty tolerances for each event and justify that the values used in the analysis are consistent with the TS required valve setpoints.

d. The St. Lucie Unit 2 reload analysis presented in Reference 3 assumes a 3-second delay time for a loss-of-offsite-power (LOOP) caused by a turbine trip. The LOOP results in loss of power to the reactor coolant pumps (RCPs) which, in turn, reduces the reactor coolant heat removal capability. Justify the 3-second delay time for a LOOP. The justification should include a discussion of the St. Lucie Unit 2 electrical system features and the grid stability analysis to demonstrate that for the licensee's unique grid system configuration, a grid instability condition following a turbine trip will take at least 3 seconds before it results in a loss-of-power to the RCPs. Applicable operational data should be submitted to validate the grid stability evaluation. Since a grid's installed capacity, demand, and spinning reserve vary over time, the licensee should discuss the measures that will be taken to ensure that real-time grid conditions will continue to meet the assumptions inherent in the 3-second LOOP delay.

e. The guidance specified in Standard Review Plan (SRP) 15.1.5, 15.2.8 and 15.6.5 indicates that the effects of a loss-of-offsite-power occurring at the worst time should be considered in the analyses of steam line break, feedwater line break and loss-of-coolant accidents, respectively. Discuss the analyses of those three accidents to confirm that the assumed time of loss-of-offsite-power is consistent with the SRP guidance. If the worst time of loss-of-offsite-power is not used in analyses of those accidents, the analyses should be redone with the time of LOOP to be consistent with the SRP guidance.

9. Computer Codes Used

a. Section 5.1.0.8 of Reference 3 indicates that the following Westinghouse computer codes are used for the St. Lucie Unit 2 reload analysis: FACTRAN (WCAP-7908) for fuel rod temperature calculations and TWINKLE (WCAP-7979) for prediction of the kinetic behavior of a reactor. Both codes were previously approved by the NRC for use in the licensing applications of Westinghouse plants. Justify that the application of those two Westinghouse codes for the St. Lucie Unit 2 (a CE plant) reload analysis is acceptable.

10. Classification of Events

    a. Section 5.1.0.9.3 of Reference 3 indicates that both complete loss of forced reactor coolant flow and full-power single Control Element Assembly (CEA) withdrawal events are classified as Conditions III events that allow a limited amount of fuel damage to occur. The classification and acceptance criteria of those two events are inconsistent with the SRP Chapter 15 guidance (15.3.1 and 15.4.3, respectively) that classifies both events as moderate frequency events with the acceptance criteria that the DNBR does not exceed the specified limit. Justify the inconsistency with the SRP guidance. Also, no results of the analysis for the full-power single CEA withdrawal event are presented in the reload analysis report (Ref. 3). Justify that the St. Lucie Unit 2 reload application without the analysis of the single CEA withdrawal event is acceptable.

11. Initial Conditions

    a. Table 5.1.0-2 of Reference 3 summarizes the values of initial plant conditions assumed in the St. Lucie Unit 2 reload analysis. For the events analyzed, different values are used for the following key plant parameters: 0, 14.2 and 20 MWt for the RCP heat; 532, 553, 560, 576.5 and 579 ^{0}F for the initial vessel average temperature; 2180, 2205, 2225, 2250 and 2400 psia for the initial pressurizer pressure; and 33.1-, 63-, 65- and 70-percent for the initial pressurizer water level.

    b. Provide the rationale for selection of the values of the initial RCP heat, vessel average temperature, pressurizer pressure and water level for each event analyzed. Justify that the initial values used result in a minimum margin to the pertinent safety limits for each analyzed event, and are applicable to the operating ranges specified in the Core Operating Limit Report (COLR) or TSs: 535 to 549 ^{0}F for the cold-leg temperature; 2225 to 2350 psia for the pressurizer pressure (COLR Table 3.2.2); and 27 to 68-percent indicated level for the pressurizer water level (page TS 3/4 4-9). Add to Table 5.1.0-1 the calculated results in terms of the minimum DNBR, peak primary and secondary pressure and the amount of fuel failed to show that the results meets the applicable acceptance criteria for each event.

12. Increase in Feedwater Flow

    a. Item 4 in Section 5.1.1.2 of Reference 3 indicates that the feedwater flow malfunction results in a step increase to 120% of the nominal full-power flow to both steam generators. It is not clear whether a limiting single failure is considered in the analysis of the increased feedwater flow event. As indicated on page 15.1-6a of the Updated Final Safety Analysis Report (UFSAR) complete opening of one feedwater control valve can increase feedwater flow over 20% above nominal. The analysis of record (AOR) for the increased feedwater flow event assumes instantaneous, complete opening of both feedwater control valves. The AOR event represents the worst increased feedwater flow event (the opening of one feedwater control valve) with the worst single failure (the simultaneous opening of the other feedwater control valve). Clarify the worst single failure assumed in the increased feedwater flow event for the St. Lucie Unit 2 reload application.

13. Pre-Trip MSLB Event

a. The current licensing basis for St. Lucie Unit 2 includes a Loss of AC Power (LOAC) concurrent with the reactor protection system (RPS) trip breakers opening (RTBO). The Standard Review Plan dictates that a LOAC be assumed to occur at the worst time during a main steamline break MSLB event. The analysis presented in the licensing amendment assumed a 3.25 second delay for the LOAC following RTBO. The staff does not agree with this change to the current licensing basis. Assuming a LOAC concurrent with RTBO, repeat the spectrum of break size and MTC cases in order to identify the limiting scenario.

b. Nominal initial conditions are assumed in this analysis. The use of off-nominal values, accounting for instrument uncertainties, has been shown to increase the DNBR degradation. Instrument uncertainties, as they relate to monitoring plant parameters and the operating tents, are accounted for in the Setpoints Methodology. However, if these same uncertainties impact the DNBR degradation, they must also be accounted for in the transient analyses. Please justify the use of nominal conditions.

c. Figure 5.1.5-7 of Reference 3, presents the DNBR degradation for the Pre-Trip MSLB event. The DNBR starts at approximately 2.2 and degrades to 1.442 before being turned around by scram CEAs.

1. Demonstrate that the initial DNBR value (approx. 2.2) is consistent with plant operations at hot full power (HFP) over the range of allowable conditions.

2. A minimum DNBR of 1.442 is reported at 12.60 seconds. It is somewhat surprising that the DNBR remains above the Specified Acceptable Fuel Design Limit (SAFDL) at a peak Core Average Heat Flux (CAHF) of 131%. Please provide all of the state parameters at the time of minimum DNBR including local peaking factors, axial power distribution, hot channel flow fraction, core average flow rate, reactor coolant system (RCS) pressure, and core inlet temperature.

d. A Variable Overpower - ΔT Power reactor trip function is credited for the Pre-Trip MSLB event.

1. Identify which power indication (either excore neutron flux detectors or core ΔT power) produces the reactor trip.

2. Demonstrate that rod shadowing and downcomer temperature decalibration effects on excore detector signals were accounted for.

3. Demonstrate that harsh environment conditions were accounted for in the RPS response and that instruments relied upon are qualified for such conditions.

e. Section 5.1.5.2 of Reference 3 states that the core radial and axial peaking factors are determined using the thermal-hydraulic conditions from the RETRAN transient simulation. Demonstrate that the effects of the time-dependent changes in coolant temperature are accounted for in the radial and axial peaking factors.

14. Post-Trip MSLB Event

a. The St. Lucie Unit 2 UFSAR presents four cases, HFP and hot zero power (HZP) with and without LOAC. It has been seen in CE plants that changes in cycle-specific physics data may change which of these four scenarios is most limiting. Further, the amendment fails to convince the staff that LOAC cases will never challenge SAFDLs.

1. Provide full scope transient simulations for these four cases.

2. Discuss how the results of these four cases will be verified as part of each reload design.

b. The change in computational methods may yield a different sensitivity to single failures. Demonstrate that a failure of one high pressure safety injection (HPSI) train remains the most limiting single failure.

c. Section 5.1.6.2 of Reference 3, states that the "initial conditions correspond to a subcritical reactor, an initial vessel average temperature at no-load value of 532 °F, and no core decay heat".

1. Does the analysis credit any initial amount of subcriticality?

2. The St. Lucie Unit 2 UFSAR analysis assumes an initial core inlet temperature of 536 °F. A higher initial temperature promotes a larger cooldown. Justify the lower value.

d. Explain the difference in steam generator (SG) blowdown between the St. Lucie Unit 2 UFSAR analysis and that presented in this license amendment. Although break size is almost identical (6.358 ft2 versus 6.305 ft2), ruptured SG dry-out times are substantially different (167 versus approximately 310 seconds).

e. Figure 5.1.6-5 of Reference 3, depicts break mass flow rate for both the faulted and intact SGs. The figure shows break flow from the faulted SG terminating at 10 seconds (main steam isolation valve (MSIV) closure). It appears that the labels for faulted and unfaulted SGs are reversed. Is this a correct assessment?

f. For each case presented, please provide a single plot of reactivity (%$\Delta\rho$) versus time for each reactivity component (total, scram, Doppler, MTC, safety injection (SI) boron).

g. The St. Lucie Unit 2 UFSAR analysis states, “the β fraction assumed is the maximum value including uncertainties..”. The UFSAR states that a maximum value maximizes subcritical multiplication and thus enhances the potential return to power. The analysis presented in the license amendment used a minimum β of 0.0044. Please discuss this inconsistency.

h. Please identify the Inverse Boron Worth (ppm/%Δρ) assumed in the analysis.

i. Section 5.1.6.2 of Reference 3 indicates that the RETRAN and ANC codes are used to verify the RETRAN prediction of the average core power/reactivity, and to determine the peaking factors associated with the return-to-power (RTP) in the region of the stuck CEA.

   1. Discuss the methods used for determining the average core power and local moderator reactivity feedback during the MSLB RTP core condition. Provide the results of analysis to demonstrate that the power/reactivity responses predicted by RETRAN are consistent with those predicted by ANC. Discuss the asymmetric cooldown effect considered in calculations of the core inlet temperature distribution. The information should include the calculated core inlet temperature distribution at the peak RTP level and a discussion of assumptions used in the calculations justified with adequate testing data.

   2. Discuss the methods used to determine the power peaking factors. Provide the values of the calculated total power peaking factors and justify that they are conservative for calculating the minimum DNBR during an MSLB.

j. Item 7 in Section 5.1.6.2 of Reference 3 indicates that the SI system is assumed to actuate when the low pressurizer pressure decreases to 1646 psia which is the safety injection actuation signal (SIAS) setpoint in the normal environment. Table 5.1.0-4 of Reference 3 indicates that the hash environment SIAS setpoint is 1578 psia which is applicable to the MSLB inside containment. Explain why the hash environment setpoint is not used in the MSLB analysis.

k. Item 11 in Section 5.1.6.2 of Reference 3 indicates that no auxiliary feedwater (AFW) is assumed to be delivered during the MSLB event. Discuss the St. Lucie Unit 2 AFW system features and the associate TS requirement to validate the assumption of the AFW model for the MSLB analysis.

l. Figure 5.1.6-4 of Reference 3 shows that the unaffected SG pressure decreases to 620 psia at about 10 seconds and starts to increase to 670 psia from 10 to 20 seconds before it continues to decrease after 20 seconds. The same figure also shows that the faulted SG pressure remains at about 50 psia from 200 to 310 seconds and then decreases to 15 psia from 310 to 340 seconds. Explain the SG pressure changes between 10 to 20 seconds, and 310 to 340 seconds.

m. Figure 5.1.6-5 of Reference 3 shows that the MSLB break flow remains at about 500 lbm/sec from 240 to 310 seconds, and then decreases rapidly to 0 lbm/sec from 310 to 340 seconds. No break flow is calculated from 340 to 355 seconds. At about 360 seconds, the break flow increases to 250 lbm/sec and remains at that level until the Figure ends at 400 seconds. Explain the break flow changes during the period from 240 to 400 seconds.

n. Figure 5.1.6-9 of Reference 3 shows that the core heat flux decreases from 5 to 1% between 10 to 20 seconds, and mains at 1% from 20 to 60 seconds before it rapidly increases after 60 seconds. Explain the core heat flux changes from 10 to 60 seconds.

o. Figure 5.1.6-11 of Reference 3 shows that the core reactivity increases to the maximum value of 0.6 at about 65 seconds, and gradually decreases before the core boron concentration (shown in Figure 5.1.6-10) starts to increase at 140 seconds. It also shows that the core reactivity decreases at a rapid rate from 310 to 320 seconds. Explain the core reactivity changes from 65 to 140 seconds and 310 to 320 seconds.

15. Loss of Normal Feedwater Flow and Loss-of-Offsite-Power

a. Section 5.1.9 of Reference 3 indicates that in the case of the LOOP event, it is assumed that the reactor is tripped prior to the LOOP. This assumption is inconsistent with the initiating event specified in SRP 15.2.6 for LOAC to the station auxiliaries. Clarify the assumption to be consistent with the SRP guidance.

b. In the same Section, the licensee claims that the long-term-cooling (LTC) analysis in UFSAR Chapter 10 remains applicable for St. Lucie Unit 2 reload application. Since the licensee uses Westinghouse methods for the reload analysis and changes the plant to a condition with the SG tube plugging increased to 30 percent, the licensee should perform the LTC analysis with Westinghouse methods to show that the auxiliary feedwater system is adequate to remove the decay heat after reactor trip for the new plant condition.

16. Loss of Condenser Vacuum

a. Section 5.1.10.2 of Reference 3 indicates that for the Main Steam System (MSS) overpressure case, the power operated relief valves (PORVs) are modeled with one valves aligned to the pressurizer and one valve locked out. Specify the lift setpoint for the PORVs and confirm that the assumption of using PORVs for mitigation of event consequences is consistent with the TS requirements. Add to Table 5.1.10-3 the time when PORVs, pressurizer safety valves (PSVs) and main steam safety valves (MSSVs) are actuated

b. Figure 5.1.10-10 of Reference 3 indicates that the calculated DNBR for the loss of condenser vacuum event increases from 2.24 to 2.34 during 10.1 to 18 seconds, and decreases to a minimum value of 2.19 at 22.1 second. Explain the DNBR changes from 10.1 to 25 seconds.

17. Asymmetric Steam Generator Transient (ASGT)

a. Item 3 in Section 5.1.11.2 of Reference 3 indicates that a bounding range of fuel to coolant heat transfer characteristics is evaluated to assure that the limiting statepoints for the ASGT event are generated. Discuss the heat transfer characteristics used to determine the statepoints and verify that the limiting statepoints are obtained.

b. Item 5 in Section 5.1.11.2 of Reference 3 indicates that the reactivity feedback is weighted to the unaffected loop since end-of life reactivity feedback is assumed. Discuss the weighted reactivity feedback model and justify the acceptability of its use for an ASGT event analysis.

c. Significant reverse flow and flow oscillation are predicted for the ASGT event: Figures 5.1.11-7 and -19 for steam flow; Figures 5.1.11-8 and -20 for MSSV Loop Bank 1 flow; Figures 5.1.11-9 and -21 for MSSV Loop 2 Bank 1 flow; Figures 5.1.11-11 and -23 for MSSV Loop2 Bank 2 flow; and Figures 5.1.11-12 and -24 for feedwater flow. Explain the flow changes predicted for the ASGT event and justify that the feedwater and steam flow models used to predict the flow are adequate and acceptable.

18. Feedwater Line Break (FLWB) Events

a. The complex, dynamic phenomena within the SG during a FWLB event, which would influence SG liquid level, primary-to-secondary heat transfer rates, break flow rate, and discharge enthalpy, are difficult to accurately simulate. The St. Lucie Unit 2 UFSAR analysis uses conservative modeling assumptions to compensate for inaccuracies of the nuclear steam supply system (NSSS) model. A best-estimate approach is attempted in this licensing amendment. Provide empirical data and benchmark cases to validate RETRAN's prediction of the following dynamic parameters for the local conditions experienced during a feedwater line break event of varying break size.

1. SG collapsed and two-phase liquid level,
2. Primary-to-secondary heat transfer rates,
3. SG Evaporator enthalpy, quality and void fraction,
4. SG Downcomer enthalpy, quality and void fraction,
5. SG Feedring enthalpy, quality and void fraction,
6. Discharge enthalpy and quality,
7. Moisture carry-over (entrained liquid), and
8. Break mass flow rate.

b. The current licensing basis for St. Lucie Unit 2 includes a LOAC concurrent with RTBO for the Condition IV event (e.g. Large FWLB). The SRP dictates that a LOAC be assumed to occur at the worst time during a MSLB event. The analysis presented in the licensing amendment assumed a 3.0 second delay for the LOAC following turbine trip. The staff does not agree with this change to the current licensing basis.

  1. Assuming a LOAC concurrent with RTBO, repeat the spectrum of break size cases in order to identify the limiting scenario for the Large FWLB event.

  2. For the Condition IV FWLB event, the break spectrum should investigate breaks starting at a minimum break size of 0.20 ft^2 .

c. Clearly define the differences in initial conditions, assumptions, and modeling techniques employed in the Chapter 15 and Chapter 10 FWLB events.

d. The MSSV and PSV opening and flow characteristics have a first order effect on calculated peak pressures.

  1. Demonstrate that the opening characteristics and lift pressures correspond to manufacturing specifications and test data for these specific valves.

  2. Demonstrate that all pressure drops leading up to the valves have been adequately accounted for in the RETRAN model. Include plant piping drawings in response to clarify calculations.

  3. Demonstrate that the safety valve flow rates are consistent with test data and were calculated with approved models.

e. During a heat-up event, a positive MTC promotes a higher peak pressure. Is the most positive MTC allowed by TSs assumed in this analysis?

f. Allowing Pressurizer Pressure Control System (PPCS) Sprays function to delay the High Pressurizer Pressure Trip (HPPT) promotes a higher calculated peak secondary pressure. Demonstrate that the peak secondary pressure case presented would not be more severe with the actuation of Pressurizer Sprays.

g. Significant detail was removed from the sequence of events tables relative to the UFSAR. All RPS, ESFAS, AFAS, MSSV/PSV actuations as well as important phenomena need to be included in the sequence of events. Please expand the current tables.

h. Discuss the sequence of events and explain the transient behavior related to the RCS pressure, vessel average temperature, SG mass and pressure, break flow rate and quality (shown in Figures 5.1.12-2 through 22) for the FWLB cases with break sizes of 0.05, 0.25 and 0.28 ft^2.

i. The Semiscale test data for FWLBs (as discussed in Section 4.3.3.1 of NUREG/CR-4945) show that the SG heat transfer capacity remains unchanged until the SG liquid inventory is nearly depleted. This is followed by a rapid reduction to zero-percent with little further reduction in the SG inventory. In light of these test data, the licensee should provide a discussion of the SG heat transfer model used in the FWLB analysis and verify that the model is conservative as compared to the Semiscale test data.

19. Decrease in Reactor Coolant Flow Rate

a. In Section 5.1.13 of Reference 3, the licensee claims that the partial loss of RCS flow does not need to be analyzed because it is bounded by a complete loss of RCS flow. Since the licensee uses Westinghouse methods and the partial loss of RCS flow may be tripped by a trip signal different from that used in analysis of a complete loss of RCS flow, the licensee should perform analyses of the partial loss of RCS flow for cases with one, two and three RCPs experiencing a pump coastdown, and confirm that the applicable acceptance criteria are met.

b. Section 5.1.14.2 of Reference 3 indicates that for the total loss of RCS flow analysis, the control rod time from release to full insertion is assumed to be 2.342 seconds. This rod insertion time is non-conservative as compared to 2.66 seconds specified in page 5-7. Clarify the inconsistency of the rod insertion time used in the analysis for various events.

20. Boron Dilution Event

a. Section 5.1.19.2 of Reference 3 indicates that for the boron dilution analysis, the dilution flow is assumed to be the maximum capacity from one charging pump for the Mode 6 and 5 cases. It is assumed to be the maximum flow from two charging pumps for the Mode 4 case with the plant on shutdown cooling system, and the maximum flow from three charging pumps flow for the Mode 4 case with the plant operating with at least one RCP running. For the Mode 3, 2 and 1 cases, the maximum capacity from three charging pumps is assumed for the dilution flow. Discuss the bases for dilution flow used in each case and confirm that the assumptions are consistent with the TS requirements of the number of operable charging pumps, operable shutdown cooling system and RCP for the applicable Modes of operation.

b. Provide the values for the maximum critical boron critical concentration, boron worth (pcm/ppm), setpoint for actuation of the boron dilution alarm system, shutdown margin and initial boron concentration used in the analysis, and confirm that the values used will result in a minimum time to reach core criticality and are consistent with the values specified in the applicable COLR or TSs.

21. Rod Ejection Event

a. Section 5.1.20-4 of Reference 3 indicates that based on the result of a generic assessment and the UFSAR analysis, the number of rods in departure from nucleate boiling (DNB) conditions is not expected to exceed 9.5%. Since the licensee uses Westinghouse methods to perform the St. Lucie Unit 2 reload analysis for plant conditions with an increase in the SG tube plugging, the generic assessment and the current UFSAR analysis are not applicable to the St. Lucie Unit 2 reload application. The licensee should perform DNBR calculations for the rod ejection event, determine the number of failed rods applicable to the St. Lucie Unit 2 reload conditions, and verify that radiological release acceptance criteria are met.

22. Chemical and Volume Control System (CVCS) Malfunction

    a. Item 3 in Section 5.1.21.2 of Reference 3 indicates that initial values of pressurizer pressure, vessel average temperature and pressurizer level are provided in Table 5.1.21-1. This Table on page 5-251 lists the sequence of events for the CVCS malfunction. Specify the correct table that contains the initial values for the pressure, temperature and water level used in the analysis.

23. Inadvertent Opening of the Pressurizer Relief Valves

    a. Section 5.1.22 of Reference 3 discusses the analysis of pressurizer pressure decrease events caused by an inadvertent opening of both of the pressurizer PORV or an inadvertent opening of a single PSV. The analysis only addresses the fuel performance issue. During the depressurization event, the pressurizer water level may increase to the top of the pressurizer, resulting in a condition outside the operable range of PSVs or PORVs. The licensee should provide information of the calculated pressured water level for the limiting water level increase case to demonstrate that the pressurizer will not fill solid with water and the PSVs and PORVs can be opened or closed on demand during the depressurization event.

24. Primary Line Break Outside Containment

    a. In Section 5.1.23.5 of Reference 3, the licensee indicates that based on its qualitative assessment, the limiting letdown line break analysis in the UFSAR remains valid. The letdown line break analysis is affected by plant parameters such as pressurizer pressure, RCS temperature and flow, initial RCS water inventory, primary- to-secondary heat transfer and the reactor trip on low pressurizer pressure signal. All those parameters are affected by decreased RCS flow and increased SG tube plugging as proposed in the St. Lucie Unit 2 reload application. The licensee's qualitative assessment is insufficient for the staff to draw the same conclusion as stated in the quoted Section. The licensee should perform a limiting letdown line break analysis with approved methods for the appropriate plant conditions that reflect the decreased RCS flow and increased SG tube plugging of 30%. The requested information should include a discussion of the methods and assumptions used in the analysis, and the results to demonstrate that the analysis meets the applicable acceptance criteria.

25. SGTR with LOOP

    a. Section 5.1.24 of Reference 3 discusses the analysis of SGTR event with respect to the mass release. The licensee should perform the SGTR event to also address the issue related to the SG overfill. The results of the analysis should demonstrate that, for the limiting conditions the SG water level condition is consistent with the assumptions used for the radiological release analysis.

26. Emergency Core Cooling System (ECCS) Performance

    a. The values for the cold-leg temperature are assumed to be 532 ^{0}F for the large-break lost of coolant accident (LOCA) analysis (Table 5.2.3.2-1 of Reference 3) and 552 ^{0}F for the small-break LOCA analysis (Table 5.2.4.2-1 of Reference 3). Justify that the LOCA analyses are applicable to the operating range of 535 to 549 ^{0}F for the cold-leg temperature specified in the proposed COLR Table 3.2.2.

27. RETRAN Model

    a. Section 3.2 of Reference 4 discusses Lower Plenum Volumes. Discuss the method, including the equations for determining these volumes, and the CE scale tests, from which the data was derived. Provide the calculated values of the design mixing characteristics used in the St. Lucie Unit 2 reload analysis, and justify that the CE scale testing data are: (1) applicable to the St. Lucie Unit 2 plant considering its RCS piping arrangement, reactor vessel internal configurations, and fuel geometry features; and (2) acceptable to support the calculated design mixing characteristics.

28. TS 6.9.1.11.b - Core Operating Limits Reports

    a. As indicated in References 2 and 5, the following topical reports are used for the St. Lucie Unit 2 reload analysis that determines the values of safety parameters, including cycle-dependent parameters that are relocated in the COLR:

        1. WCAP-9226 discussing the methods for the steam line break analysis,

        2. WCAP-14482-P-A, discussing the RETRAN code for the non-LOCA transient analysis, and

        3. CE-161, Supplement 1-P-A discussing the FATES-3B code for evaluation of the fuel performance.

    Reference 2 does not clearly state whether those reports are included in TS 6.9.1.11.b, or are referenced by a report that is listed in TS 6.9.1.11.b. Generic Letter (GL) 88-16 indicates that the approved topical report should be included in an administrative control document when that report is used to determine cycle-dependent parameters that are located in the COLR. According to GL 88-16, those three reports should be included in TS 6.9.1.11.b. Address consistency with the GL 88-16 guidance for those three reports.

<u>REFERENCES</u>:

1. Letter from W. Jefferson (FPL) to NRC, “St Lucie Unit 2, Docket No. 50-389, Proposed License Amendment WCAP-9272 Reload Methodology and Implementing 30% Steam Generator Tube Plugging Limit,” dated December 2, 2003.

2. Attachments 1 and 3 to Reference 1, “Description of the Proposed Changes and Justification”, and ”St Lucie Unit 2 Marked-up Technical Specification Pages”, respectively.

3. Attachment 6 to Reference 1, “Westinghouse Licensing Report St Lucie 2 30 Percent Steam Generator Tube Plugging and WCAP-9272 Reload Methodology Transition Project.”

4. Attachment 7 to Reference 1, “Proprietary Portions of Westinghouse Licensing Report St Lucie Unit 2 30-Percent Steam generator Tube Plugging and WCAP-9272 Reload Methodology Transition Project - Appendix C.”

5. Appendix B to Reference 3, “ Conditional Requirements.”