FPL

Florida Power & Light Company, 6501 S. Ocean Drive, Jensen Beach, FL 34957

December 10, 2004

L-2004-287
10 CFR 50.90

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

RE: St. Lucie Unit 2
Docket No. 50-389
Proposed License Amendment
Second Request for Additional Information Response
WCAP-9272 Reload Methodology and
Implementing 30% Steam Generator Tube Plugging Limit

The response to the second NRC request for additional information (RAI) dated November 19, 2004 is attached. Florida Power & Light Company (FPL) requested to amend Facility Operating License NPF-16 for St. Lucie Unit 2 by FPL letter L-2003-276 dated December 2, 2003. The purpose of the proposed license amendment is to allow operation of St. Lucie Unit 2 with a reduced reactor coolant system (RCS) flow, corresponding to a steam generator tube plugging level of 30% per steam generator. The re-analysis performed to support this reduction in reactor coolant system (RCS) flow has used Westinghouse WCAP-9272, Westinghouse Reload Safety Evaluation Methodology. The implementation of these changes required changes to the current Technical Specifications (TS).

FPL responded to the first NRC RAI dated June 21, 2004 by FPL letter L-2004-193 dated September 14, 2004. Subsequent to that submittal FPL, Westinghouse, and NRC discussed additional issues on November 23, 2004 and December 2, 2004.

The proposed amendment included the following Technical Specifications changes: revision to the Thermal Margin Safety Limit Lines TS Figure 2.1-1, reduction in RCS flow in TS Table 3.2-2 and in footnote to TS Table 2.2-1, changes to positive MTC in TS 3.1.1.4, changes to surveillance requirements for Linear Heat Rate TS 3/4.2.1, deletion of Fxy TS 3/4.2.2, relocation to core operating limits report (COLR) of departure from nucleate boiling (DNB) parameters in TS 3.2-5, changes to Design Features Fuel Assemblies TS 5.3.1, deletion of Design Features RCS Volume TS 5.4.2, COLR methodology list update in TS 6.9.1.11b and conforming changes to TS 1.38, TS 3.2.4, TS 3/4.10.2, and TS 6.9.1.11a.

To address expected increases in steam generator tube plugging (SGTP) for the current steam generators, analyses have been performed that support the operation of St. Lucie Unit 2 at 100% of rated thermal power (2700 MWt), with the following conditions:

1. Maximum SGTP of 30% in each of the two steam generators.
2. Maximum tube plugging asymmetry of 7% between the two steam generators.
3. A reduction in the Technical Specifications required minimum RCS flow from the current value of 355,000 gpm to 335,000 gpm.

The analyses are to be implemented for St. Lucie Unit 2 Cycle 15, which is planned to begin operation in late January 2005. These analyses involve changes to the reload analysis methodology to improve and streamline the reload process related to cycle-specific physics calculations performed as part of the safety analysis checklist.

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The original determination of No Significant Hazards consideration remains bounding. In accordance with 10 CFR 50.91 (b)(1), a copy of the proposed amendment is being forwarded to the State Designee for the State of Florida.

Approval of this proposed license amendment is now requested by January 2005 to support the reload analyses for St. Lucie Unit 2 Cycle 15. Please issue the amendment to be effective on the date of issuance and to be implemented within 60 days of receipt by FPL. Please contact George Madden at 772-467-7155 if there are any questions about this submittal.

Very truly yours,

William Jefferson, Jr.
Vice President
St. Lucie Plant

WJ/GRM

cc: Mr. William A. Passetti, Florida Department of Health

STATE OF FLORIDA)
) ss.
COUNTY OF ST. LUCIE)

William Jefferson, Jr. being first duly sworn, deposes and says:

That he is Vice President, St. Lucie Plant, for the Nuclear Division of Florida Power & Light Company, the Licensee herein;

That he has executed the foregoing document; that the statements made in this document are true and correct to the best of his knowledge, information, and belief, and that he is authorized to execute the document on behalf of said Licensee.

William Jefferson, Jr.

STATE OF FLORIDA

COUNTY OF ST LUCIE

Sworn to and subscribed before me

this 10 day of December, 2004
by William Jefferson, Jr., who is personally known to me.

Carla J. Heinold
Name of Notary Public - State of Florida

NOTARY PUBLIC STATE OF FLORIDA
OFFICIAL NOTARY SEAL
CARLA J HEINOLD
COMMISSION NUMBER
DD021761
MY COMMISSION EXPIRES
APR. 30, 2005

CARLA J. HEINOLD
(Print, type or stamp Commissioned Name of Notary Public)

Attachment

Second Request for Additional Information Response

WCAP-9272 Reload Methodology and

Implementing 30% Steam Generator Tube Plugging Limit

<u>NRC Request 1.a:</u> The following issues should be addressed to support the acceptability of the proposed delay time for a loss-of-offsite power (LOOP) following turbine trip assumed in the Main Steam Line Break (MSLB) analysis.

a. Provide an evaluation of the St. Lucie plant-specific design features that justify the use of the chosen time delay for the consequential LOOP. The following possibilities should be addressed for the St. Lucie site-specific electrical design: degraded switchyard voltage, spurious switchyard breaker-failure-protection-circuit actuation, automatic bus transfer failure, and startup transformer failure. One approach would be to address the events identified in Table G.5 of the "Technical Work to Support Possible Rulemaking for a Risk-Informed Alternative to 10 CFR [*Code of Federal Regulations, Section*] 50.46/GDC [General Design Criterion] 35" (ML022120661), which indicates that these are the likely causes of a consequential LOOP.

<u>FPL Response 1.a:</u>

The following supplemental information is provided to add on to the response to RAI 8.d in FPL letter L-2004-193:

1. The turbine/reactor/generator trips occur essentially simultaneously with no intentional time delays. The generator does not remain connected for any time following a turbine trip.

2. 6.9kV System Description:

   The non-nuclear safety-related 6.9kV system for each unit consists of two separate 6.9kV switchgear busses, powered from two independent sets of transformers (unit auxiliary transformers and startup transformers). Each 6.9kV bus supports two reactor coolant pumps (RCPs) and one main feedwater pump. Power for each 6.9kV bus is normally supplied from either a main generator-connected unit auxiliary transformer (UAT) when the unit is online, or from an offsite power-fed startup transformer (SUT) when the unit is offline. Each 6.9kV bus is fed from a separate UAT or SUT.

   The two RCPs connected to each of the 6.9kV busses are in different loops feeding different steam generators. Thus, loss of a 6.9kV bus would leave one RCP operating in each steam generator loop.

3. Switchyard Degraded Voltage:

   Recent analyses of the St. Lucie switchyard for various contingencies involving grid disturbances and plant trips shows that in each case response of the grid results in stability within a short time (reference Unit 1 UFSAR, Section 8.2, Amendment 20; Unit 2 UFSAR Section 8.2 is scheduled for update with the same information following the upcoming outage). One case studied is that during a period with maximum grid loading, Unit 2 is assumed off line and Unit 1 trips. Analysis of the resulting grid disturbance using computer modeling shows that the switchyard voltage drops from 104.3% to 101.8% of 230kV (239.89kV to 234.14kV) and the frequency briefly dips to 59.94Hz and recovers to 59.99Hz. Accompanying plots of the grid response show grid stability is obtained within 10 seconds.

   Based on the above, an assumed minimum switchyard voltage of 230kV was used for evaluation of the nuclear safety-related electrical system degraded voltage protection system (PSB-1 relay calculations). Switchyard voltages below 230kV are considered to be

insufficient for Class 1E equipment for PSB-1 events and would result in degraded voltage relay operation on the nuclear safety-related busses under certain scenarios.

Therefore, an assumed minimum switchyard voltage of 230kV is considered appropriate for evaluation of the non-nuclear safety-related 6.9kV system during a degraded offsite voltage condition.

4. Spurious Actuation of Switchyard Breaker Failure Protection Circuit:

   a. 230kV Busses:

      The 230kV switchyard design consists of two parallel 230kV busses, the east bus and west bus, with loads and outgoing lines connected between them in a breaker-and-a-half scheme. Actuation of the main transformer switchyard breaker failed breaker protection, either spuriously or due to a failed breaker, would result in opening of the next set of breakers upstream. This could cause the de-energization of the east bus, but not the west bus. Prior to the loss of the east bus, the SUTs are connected to both the east and west busses. With the trip of the east bus, the SUTs would remain energized from the west bus. This is not a transfer and there will be no loss of power to the transformer.

   b. Startup Transformer Feeders:

      Two feeders from the 230kV switchyard provide power to the four SUTs (Unit 1: 1A and 1B; Unit 2: 2A and 2B) such that SUTs 1A and 2A share one switchyard feeder and SUTs 1B and 2B share the other switchyard feeder. Failure of one of the 230kV SUT feeders would affect one 6.9kV bus on both Unit 1 and Unit 2; however, the second 6.9kV bus on each unit would be unaffected. A spurious actuation of the SUT switchyard breaker failure protection circuit for one of the SUT switchyard breakers would result in the de-energization of one of the two SUT feeders, thereby, disabling one SUT on each unit. However, the remaining SUT on each unit would not be affected.

5. Automatic Bus Transfer Failure:

   a. An automatic one-way fast dead-bus transfer of the 6.9kV system busses from the UATs to the SUTs occurs in the event of a unit trip.

   b. Transfer is initiated by the primary and/or backup generator lockout relays that also function to trip the generator by opening the switchyard breakers associated with the main transformers.

   c. Opening of the UAT and closing of the SUT 6.9kV breakers occurs simultaneously. Transfer occurs in approximately 5 cycles (0.083 second) with a 10-cycle (0.17 second) maximum time.

   d. Failure of an SUT breaker to close or a UAT breaker to open would result in a failure of the automatic transfer of the associated 6.9kV bus. However, the redundant 6.9kV bus would remain unaffected.

6. Startup Transformer Failure:

   Failure of an SUT subsequent to bus transfer would result in loss of the associated 6.9kV bus and two RCPs. However, the other SUT, 6.9kV bus and two RCPs would not be affected. It should be noted that the SUTs are energized but not loaded during normal plant operation. An electrical fault in the plant distribution system would not draw fault current through the SUT. Therefore, the fault could not result in damage to the SUT. It should be noted that none of the transformers at St. Lucie have automatic tap changing or voltage regulating equipment; therefore, failures associated with such equipment could not occur. Also, internal failure of an SUT prior to a transfer is more likely to be detected and corrected because the transformers are maintained in an energized condition and are monitored.

7. Conclusion:

   Review of the St. Lucie site-specific electrical design for spurious switchyard breaker-failure-protection-circuit actuation, automatic bus transfer failure, and startup transformer failure shows that the immediate loss of one 6.9kV bus and the associated two RCPs due to plant-centered failures following a reactor/turbine/generator trip is possible as a result of a plant-centered component failure. However, there are no apparent common-mode failures that would result in loss of both 6.9kV busses. At least one 6.9kV bus would remain connected to offsite power and thus would remain energized for the time delay period until a loss of offsite power due to loss of the grid occurs. Therefore, it can be concluded that at least two RCPs, one in each steam generator loop, would be available immediately following a reactor/turbine/generator trip.

   A review of the St. Lucie site-specific electrical design with respect to a degraded switchyard voltage condition is addressed within the response to Information Request 1.b.

NRC Request 1.b: Since the non-safety 6.9kV system does not have degraded voltage protection relays, please verify that if a degraded voltage condition were to occur as a result of the loss of the St. Lucie 2 generator following an RCP shaft seizure event or a steam line break event, the 6.9kV loads, including the RCPs, would remain energized and would not trip due to some other protective system action such as overcurrent relaying or motor overload protection. The voltage used for this determination should be the lowest voltage that the grid surrounding St. Lucie 2 can support without becoming unstable or undergoing a voltage collapse. At this voltage also provide the speed and flow reduction that would occur on the 6.9kV motors, including the RCPs.

FPL Response 1.b:

The following discussion evaluates the 6.9kV system in the event of a degraded voltage event resulting from unit trip.

1. 6.9kV Bus Undervoltage/Degraded Voltage Protection:

   The 6.9kV system does not have degraded voltage protection relays. However, each 6.9kV bus is monitored for a loss of bus voltage by an undervoltage relay that acts to trip the bus loads at approximately 64% nominal bus voltage. Failure of a relay or the potential transformer circuit connected to it or incorrect setting of that relay could result in a trip of all loads on the associated 6.9kV bus. The redundant 6.9kV bus would not be affected.

2. Bus Minimum Voltage:

   The current tap settings for all SUTs are position #4, resulting in a ratio of 224.25kV/6.9kV. With an assumed 230kV switchyard voltage, the equivalent unloaded voltage on the 6.9kV busses is 7.077kV. Evaluation of voltage at the 6.9kV busses during plant operation with the switchyard at 230kV is contained in the short circuit, voltage drop and PSB-1 relay calculations for each Unit. Within these calculations, the minimum Unit 2 6.9kV bus voltage is 99.68% (6877.92V). It should be noted that these voltages are for a SIAS event with offsite power, prior to the start of SIAS-actuated components. Motors for the reactor coolant pumps and main feedwater pumps were procured with a standard terminal voltage rating of 6.6kV for operation on a 6.9kV system. This standard rating allows for a design voltage drop of 300V from bus to motor terminals; the actual voltage drop can be expected to be less than that. Given a 300V voltage drop and a bus voltage of 6877.9V, the motor terminal voltage would be approximately 6577.9V, which is 99.7% of the nominal motor terminal voltage rating. Therefore, there would be no significant effect on pump speed and flow due to degraded voltage.

3. Protective Relaying Evaluation:

   a. Reactor Coolant Pumps

      1) Motor Rating: 6600V, 6500HP, 1.15 service factor, full load amps = 502A, locked rotor amps = 3340A.

      2) Protective relaying for the reactor coolant pumps consists of inverse time overcurrent and instantaneous overcurrent.

         a) The inverse time overcurrent protection relay setpoint is based on 640A (approximately 127% of the full load current). The settings used result in a minimum trip of 960A with a time delay of 25 seconds; higher currents would result in a faster trip. This is equivalent to 191% of the full load current. Assuming a constant-kVA motor model, the voltage would have to decrease to approximately 52% nominal value (3451V) to result in a 191% increase in full load current. Since the actual voltage decrease is less than 10%, as discussed above, the resultant increase in full load current would be significantly less than 191%. Therefore, a motor trip on overload during degraded voltage conditions (230kV in the switchyard) would not be expected to occur.

         b) The instantaneous overcurrent protection setpoint is based on a minimum 250% of the full load current and is thus significantly higher than the inverse time overcurrent setting. Therefore, a motor trip on instantaneous current protections would not be expected during degraded voltage conditions since a trip on overload would not occur under these conditions.

         c) Locked rotor current is not a factor since these motors continue to run and do not start during the event and as the voltage dip is insufficient to cause motor stalling.

b. Main Feedwater Pumps

1) Motor Rating: 6600V, 7000HP, 1.15 service factor, full load amps = 530A, locked rotor amps = 3400A.

2) Protective relaying for the main feedwater pumps consists of inverse time overcurrent and instantaneous overcurrent.

a) The inverse time overcurrent protection relay setpoint is based on 640A (approximately 121% of the full load current). The settings used result in a minimum trip of 960A with a time delay of 22 seconds; higher currents would result in a faster trip. This is equivalent to 181% of the full load current. Assuming a constant-kVA motor model, the voltage would have to decrease to approximately 55% nominal value (3644V) to result in a 181% increase in full load current. Since the actual voltage decrease is less than 10%, as discussed above, the resultant increase in full load current would be significantly less than 181%. Therefore, a motor trip on overload during degraded voltage conditions (230kV in the switchyard) would not be expected to occur.

b) The instantaneous overcurrent protection setpoint is based on a minimum 250% of the full load current and is thus significantly higher than the inverse *time overcurrent setting. Therefore, a motor trip on instantaneous current* protections would not be expected during degraded voltage conditions since a trip on overload would not occur under these conditions.

c) Locked rotor current is not a factor since these motors continue to run and do not start during the event and as the voltage dip is insufficient to cause motor stalling.

c. 6.9kV Bus Incoming Circuit Breaker

1) Protective relaying for the 6.9kV bus incoming breaker consists of inverse time overcurrent and instantaneous overcurrent (the instantaneous overcurrent is used as a fault monitor). During normal plant operation, the incoming breaker sees the combined full load currents of two reactor coolant pumps and one main feedwater pump. Therefore, during a degraded voltage condition, the incoming breaker must be able to supply the combined load at the increased running currents (due to the lower voltage) without tripping. It should be noted that a trip of the incoming feeder breaker would result in loss of both RCPs and the main feedwater pump on the associated 6.9kV bus.

2) The inverse time overcurrent relay setpoint is based on approximately 150% transformer rating. The settings used result in a minimum trip of 6000A with a time delay of 7 seconds; higher currents would result in a faster trip. Combined nominal full load current of two RCPs and one main feedwater pump is 1534A (2 x 502 + 530). Again, assuming a constant-kVA motor model, the voltage would have to decrease to 25.6% nominal (1687V) to result in sufficient current to trip. Since the anticipated voltage during a degraded voltage condition would be significantly greater than 25.6%, trip of the bus incoming circuit breakers would not be expected.

4. Conclusion:

   It is concluded that there should be no significant effect on operation with respect to either speed or capacity of either the reactor coolant pumps or main feedwater pumps due to a degraded voltage condition with the switchyard at a minimum voltage of 230kV.

   a. Motor terminal voltage is only 0.3% below nominal, given an assumed 300V voltage drop between the bus and motor terminals. This voltage is well within the ±10% allowed by NEMA MG 1-2003. The actual voltage drop would be expected to be less than this for motors operating at steady-state full load current values.

   b. St. Lucie general design practice is to size motors larger than the required brake horsepower, thereby, providing greater design margin that would tend to counter the minor reduction in flow at degraded voltage.

   c. The RCPs have integral flywheels that would act to provide energy for a brief period following reduction of voltage, further minimizing the effects of degraded voltage on RCP flow during the initial few seconds of degraded voltage.

   d. Inverse time overcurrent and instantaneous overcurrent protection for the reactor coolant pumps and main feedwater pumps will not actuate prematurely to trip the breakers, with resulting loss of flow, during a degraded voltage event.

   e. Trip of the 6.9kV bus incoming feeder breaker due to inverse time overcurrent or instantaneous overcurrent protective relay actuation will not occur during degraded voltage conditions.

<u>NRC Request 1.c:</u> For the MSLB event that involves the actuation of Emergency Core Cooling Systems (ECCS) it is also important to know the LOOP delay times (if any) that would occur on the 4.16kV safety-related system. Please provide an analysis on the 4.16kV safety-related system similar to that done for the non-safety 6.9kV system. The analysis should evaluate the consequential LOOP possibilities identified in the staff's original question 1.a and should provide the time delays (if any) associated with each.

<u>FPL Response 1.c:</u>

The following is an evaluation of the St. Lucie Unit 2 4.16kV system.

1. System Description:

   The 4.16kV system for Unit 2 consists of two redundant non-nuclear safety-related busses and two redundant nuclear safety-related busses. Each non-nuclear safety-related bus can be powered from either the UAT or SUT, with automatic one-way transfer as described above for the 6.9kV system. Each nuclear safety-related 4.16kV bus is powered from its associated non-nuclear safety-related 4.16kV bus via breakers. The breakers remain closed during an automatic transfer from the UAT to the SUT. However, in the event of a loss of voltage or degraded voltage situation, protective relays act to separate the nuclear safety-related bus from its associated non-nuclear safety-related bus by opening the nuclear safety-related bus incoming feeder breakers.

2. Undervoltage/Degraded Voltage Protection:

   The nuclear safety-related 4.16kV system is protected by both undervoltage and degraded voltage relays; however, some of the degraded voltage relays are physically located on the 480V system. Further description of the undervoltage and degraded voltage protection can be found in Section 8.3 of the Unit 2 UFSAR. In the event bus voltage falls below any of the relay setpoints, the associated time delay is activated. If bus voltage has not recovered before the end of the time delay, the relays act to separate the nuclear safety-related 4.16kV busses from the non-nuclear safety-related 4.16kV busses, initiate bus load shed and start the emergency diesel generators (EDG). Undervoltage protection is provided by two relays connected in a two-out-of-two logic. Failure mode for these relays is in the actuated (i.e. loss of voltage) condition. Thus, failure or incorrect setting of a single relay would not result in spurious actuation of the undervoltage protection. Degraded voltage protection consists of more than one level of protection, as described in Section 8.3 of the Unit 2 UFSAR. Each level has three degraded voltage relays connected in a two-out-of-three logic. Therefore, failure or incorrect setting of a single relay would not result in spurious actuation of the degraded voltage protection. Failure of one of the associated potential transformer circuits would cause dropout of all the connected undervoltage/degraded voltage relays and result in similar actions to those for an actual LOOP. However, this failure would affect only the associated 4.16kV bus; the redundant 4.16kV bus would remain unaffected.

   Each of the non-nuclear safety-related 4.16kV buses is protected by a single undervoltage relay, similar to the 6.9kV busses, without degraded voltage protection. Failure of that relay or the potential transformer circuit connected to it or incorrect setting of the relay would also result in similar actions to those for an actual LOOP, including separation of the nuclear safety-related 4.16kV bus, load shed and EDG start. Again, in either case the failure would affect only the associated bus and not the redundant non-nuclear safety-related 4.16kV bus.

3. Auto Transfer Failure:

   Similar to the 6.9kV system, failure of the SUT breaker to close or the UAT breaker to open would result in a failure of the automatic transfer. The result would be essentially a LOOP for that electrical train, with consequential separation of the affected nuclear safety-related bus from the non-nuclear safety-related bus, load shed and start of the EDG. The redundant electrical train would not be affected.

4. Startup Transformer Failure:

   Similar to the arrangement for the 6.9kV system, each 4.16kV electrical train is powered from a separate SUT. Failure of an SUT subsequent to transfer would result in a LOOP to the associated electrical train, causing load shed, EDG start, and load sequencing onto the EDG of required loads. The redundant electrical train would not be affected. Also, internal failure of an SUT prior to a transfer is more likely to be detected and corrected because the transformers are maintained in an energized condition and are monitored.

5. LOOP Delay Times:

   Analysis of the LOOP delay times for an MSLB event that involves the actuation of the ECCS is given in the response to Information Request 1.d, below. This analysis assumes a 3 to 3.3-second delay in loss of offsite power due to decay of voltage and frequency of the grid following a plant trip.

In the case where offsite power to one 4.16kV electrical train is lost due to one of the failures discussed above, the LOOP delay times would consist of the following:

Time (Sec.)	Events
0	• LOOP occurs, bus voltages go to 0, MCC contactors for energized loads drop out.
1	• UV relays initiate load shed of 6.9kV, 4.16kV and 480V switchgear loads and start EDGs.
11	• EDGs at voltage and frequency, EDG breaker closes, busses re-energized. • Component cooling water pumps start (not tripped on load shed). • Charging pumps start (not tripped on load shed). • Other LOOP loads start sequencing in accordance with design.

It should be noted that this would occur only on the affected train.

6. Conclusion:

A plant-centered component failure following a reactor/turbine/generator trip could result in one 4.16kV system experiencing a LOOP with loss of function of the non-nuclear safety-related bus components, thereby, initiating load shedding, and starting the EDG with load sequencing of required components on the nuclear safety-related bus. Since each redundant 4.16kV system is powered from a separate UAT and SUT, there is no common-mode transformer or automatic transfer failure that would result in a LOOP to both 4.16kV systems simultaneously.

<u>NRC Request 1.d:</u> Because the Steam Line Break (SLB) event involves the actuation of Emergency Core Cooling Systems (ECCS), the consequences of the delayed LOOP on the performance of the electrical ECCS systems should be evaluated. The consequences of double sequencing and its associated vulnerabilities that would occur as the result of the delayed LOOP should be a part of this evaluation. These vulnerabilities include, but are not necessarily limited to: the consequences of starting large continuous-duty motors twice in quick succession with the first start under degraded voltage conditions and the second start with pump discharge valves open; the adequacy of the existing control logic to start loads on offsite power, shed those loads following the LOOP, and subsequently re-sequence those loads on the Emergency Diesel Generators (EDGs) with necessary delay to allow motor residual voltage to decay; interaction between the double sequencing and circuit breaker anti-pump logic that could lock out the breakers; the capability of the safety batteries to operate the necessary systems during an initial offsite power degraded voltage ECCS start and subsequently restart the ECCS on EDGs; and the potential to trip motor overload protection or blow fuses as a result of a degraded voltage double sequencing scenario.

FPL Response 1.d:

The following is an evaluation of a unit trip with SIAS and Delayed LOOP.

1. Event Scenario:

The scenario under review in this case consists of a unit trip and simultaneous SIAS actuation, followed in 3 to 3.3 seconds by a LOOP caused by loss of generation to the offsite grid from the unit. The effects of a steam line break and probable main steam isolation signal (MSIS) are not discussed since no major electrical components are started as a result. It should be noted that, as discussed in UFSAR Section 8.2, the Florida grid has been evaluated for a situation with one St. Lucie unit offline and a sudden trip of the second St. Lucie unit. The analysis was performed by FPL Transmission & Distribution Systems group using dynamic simulation software with the assumption that a peak load was present on the grid. The results show that the grid response is stable with minimal change to voltage and frequency resulting from the sudden trip of one St. Lucie unit. However, the following discussion assumes that trip of one unit results in the decay of voltage and frequency on the offsite grid with a LOOP occurring 3 to 3.3 seconds after unit trip.

The proposed timeline for this scenario is as follows (all times are approximate):

Time (Sec.)	Events
0	• SIAS with reactor / turbine / generator trip. • Switchyard breakers for the main transformers trip open. • Auto transfer of 6.9kV & 4.16kV busses from unit auxiliary transformers to startup transformers initiated by generator lockout due to turbine trip. • SIAS – actuated loads start. This includes high pressure safety injection and low pressure safety injection pumps and motor operated valves (MOVs). • EDGs start on SIAS.
3 to 3.3	• LOOP occurs, bus voltages go to 0, MCC contactors drop out, MOVs stop.
4 to 4.3	• UV relays* initiate load shed of 6.9kV, 4.16kV & 480V switchgear loads.
6	• Permissive for EDG breaker closure is satisfied; however, EDGs have not attained voltage and/or frequency so EDG breaker remains open.
10	• EDGs at voltage and frequency, EDG breaker closes, busses re-energized. • Component cooling water pumps start (not tripped on load shed). • Charging pumps start (not tripped on load shed). • AC MOVs resume stroking. • Other LOOP/SIAS loads start sequencing in accordance with design.

* UV relays have an inherent 1 second time delay for actuation.

Unit trip, consisting of a turbine, reactor, and main generator trips, results in opening of the main transformer circuit breakers in the switchyard and simultaneous fast transfer of both the 6.9kV and 4.16kV systems from the unit auxiliary transformers (fed from the main generator) to the startup transformers (fed from offsite power). This transfer is described in the response to Information Request 1.a., above.

2. Multiple Motor Starts:

   The only major loads started in response to SIAS are the high pressure safety injection (HPSI) pump, low pressure safety injection (LPSI) pump, which do not run during normal plant operation, and the charging pump(s) which may or may not be running. Other loads, such as the component cooling water and intake cooling water pumps, are normally running and will continue to run upon receipt of a SIAS. Therefore, the only major motors that could experience two starts in quick succession are the HPSI, LPSI, and charging pumps. NEMA MG 1-2003, Section 20.12, specifies motor design to allow two starts with the motor initially at ambient temperature, one start with the motor at operating temperature. Generally, it is recommended that a reasonable time be allowed between successive starts for large motors to allow the motors to cool off from the heat generated by starting current. Permitting restart of the motor before it has a chance to cool off results in a potential for elevated winding temperatures in the motor. This would possibly shorten the motor lifespan due to aging, but would not present a concern for immediate motor failure. Therefore, multiple motor starts is not seen as a concern for safety-related component operability.

   In response to the SIAS, the HPSI and LPSI pump discharge and flow control valves start to open. These valves have stroke times of approximately 10 to 15 seconds. Under the proposed scenario, the MOVs would stroke for about 3.3 seconds, then would stop when the LOOP occurs. Valve stroke would recommence when the EDG breaker closes. The LPSI and HPSI pumps are sequenced to start 3 seconds and 6 seconds after EDG breaker closure, respectively. Therefore, the MOVs have not finished stroking and would likely not be completely open when the pumps restart on the EDG.

3. Control Logic Adequacy:

   The control logic that performs the functions of SIAS actuation, load shed following detection of degraded or loss of bus voltage and sequencing of loads on the EDGs is capable of performing these functions without operator intervention.

   a. The relays that provide the SIAS are normally energized, de-energize upon occurrence of SIAS, and remain de-energized until manually reset. Control power for actuation of SIAS is derived from the 125VDC system and is backed by the nuclear safety-related batteries. Thus, a degraded offsite voltage or loss of 4.16kV or 480V bus voltage will not prevent the SIAS logic from functioning as designed.

   b. Load shed on the 4.16kV and 480V safety-related busses occurs after detection of a degraded or loss of bus voltage with time delays as specified in the Technical Specifications. Control power is derived from the 125VDC system and is not affected by a degraded or loss of voltage condition. Reset of the degraded/loss of voltage relays is automatic and does not require manual actions.

c. Loads connected to the MCCs drop-out upon loss of bus voltage. Evaluations have been performed to ensure control components have adequate voltage to perform their functions during a degraded voltage condition.

d. Only circuit breakers on the 6.9KV, 4.16kV and 480V switchgear have anti-pumping relays. Switchgear breakers that are load shed are tripped by the undervoltage/degraded voltage logic. Since SIAS is a locked-in signal, the breaker close circuit would be continually energized and would activate the breaker anti-pump relay logic. However, a bus load shed relay contact interrupts the breaker close circuit upon loss of power, resetting the anti-pump relay logic. Switchgear breakers that are not load shed remain closed and are re-energized when the EDG breaker closes. Therefore, the anti-pump relay logic does not affect those breakers required to operate.

4. Motor Residual Voltage Decay:

The EDG output breakers have a permissive that prevents breaker closure for two seconds after detection of a loss of bus voltage. Thus, the minimum time between motor de-energization and re-energization is two seconds, assuming the EDG was already at rated voltage and frequency when the LOOP occurs. This time delay specifically allows for voltage decay prior to re-energization of the major motors that start in the first load block upon EDG breaker closure. Other motors starting in subsequent load blocks will have additional time for voltage decay.

5. Battery Capacity:

The safety-related batteries for St. Lucie Unit 2 are sized for a four-hour duty cycle in the event of a LOOP and EDG start failure (Station Blackout scenario). Included in the assumed loads are automatic load-shedding of the 4.16kV and 480V switchgear, EDG control power, EDG field flash and EDG breaker closing coil, and the end of the 4-hour period. At the end of the duty cycle, the nuclear safety-related busses are re-energized from the EDG and the battery chargers are available.

The scenario under review for this Information Request assumes successful EDG start, which involves a 10-second EDG start time plus 30-second battery charger sequential load time. Therefore, the time required for battery support of control power is approximately 40 seconds. The batteries are adequate for this shorter time. It should be noted that the initial SIAS actuations occur when offsite power is available; therefore, 125VDC control power would be derived from the battery chargers up to the point the LOOP occurs.

6. Motor Overload Protection:

Motor overload protection for nuclear safety-related motors during a degraded voltage condition has been evaluated as part of the PSB-1 degraded voltage relay setpoint calculations and has been determined to be adequate. Premature trip of nuclear safety-related motor loads would not be expected.

7. Conclusion:

Response of the St. Lucie Unit 2 electrical system to a SIAS with delayed LOOP would result in a start of SIAS-actuated loads, EDG start, safety bus load shed (upon receipt of LOOP signal), EDG breaker closure and sequencing of the LOOP/SIAS loads onto the

EDGs as described in Section 8.3 and Table 8.3-2 of the Unit 2 UFSAR. This is in accordance with the design basis for the St. Lucie nuclear safety-related electrical system.

The scenario timeline for a SIAS with delayed LOOP is shown in Section 1, above, and includes both the 6.9kV and 4.16kV systems. Potential failures and consequential LOOP possibilities are discussed in Sections 2 through 6. No common-mode plant-centered failures were noted that would result in disabling all four RCPs or both nuclear safety-related electrical trains simultaneously.

It should also be noted that loss of Unit 2 with SIAS during peak grid loading would have a minimal effect on the distribution grid voltage and frequency that would not result in a LOOP condition, as analyzed in Section 8.2 of the UFSAR.

<u>NRC Request 1.d Part 2:</u> In discussions with the NRC staff, FPL stated that a review of all the Mode 1 SLB analysis cases analyzed found that, in all cases where reactor trip/turbine trip occurred, that the LOOP with the 3-second delay occurred prior to the time where the Safety Injection signal would occur. Therefore, there is no direct double sequencing concern for these steam line break event analysis cases.

1) Rather than assuming a 3-second LOOP time delay, please provide a LOOP/Safety-Injection-Signal analysis using the LOOP time delays determined from your analysis that will be provided in response to question 1.c above. With regard to the degraded-voltage LOOP possibility, we note that for safety-related systems, one of the most likely times for separation of safety equipment from offsite power due to degraded voltage relay operation is during or immediately following ECCS energization on offsite power.

2) If your analysis still finds the safety injection signal will follow the LOOP, the consequences of the LOOP/delayed ECCS actuation on the performance of the electrical ECCS should be evaluated. The potential vulnerabilities that should be evaluated include, but are not necessarily limited to: the potential for overloading the emergency diesel generators (EDGs) as a result of simultaneously block loading or load sequencing LOOP loads and ECCS loads onto the EDGs, the potential for overloading the EDGs as a result of block loading or load sequencing ECCS loads onto operating EDGs that are powering LOOP loads, and the adequacy of existing control logic to power LOOP loads from the EDGs following the LOOP signal and then properly add ECCS loads to the already operating EDGs.

<u>FPL Response 1.d Part 2:</u>

The following is an evaluation of a unit trip with an assumed LOOP with delayed SIAS.

1. Event Scenario:

This scenario consists of a unit trip, followed in 3 to 3.3 seconds by a LOOP caused by loss of generation to the offsite grid from the unit. A SIAS is assumed to occur at some time after the EDG breaker has closed and load sequencing has begun. Again, the effects of a steam line break and probable main steam isolation signal (MSIS) are not discussed since no major electrical components are started as a result. As discussed in the response to Information Request 1.d., above, analysis of the offsite grid response to a unit trip shows stability with minimal change to voltage and frequency. However, the following discussion

assumes that a trip of one St. Lucie unit results in the decay of voltage and frequency on the offsite grid with a LOOP occurring 3 to 3.3 seconds after unit trip.

The proposed timeline for this scenario is as follows (all times are approximate):

Time (Sec.)	Events
0	• Reactor / turbine / generator trip. • Switchyard breakers for the main transformers trip open. • Auto transfer of 6.9kV and 4.16kV busses from unit auxiliary transformers to startup transformers initiated by generator lockout due to turbine trip.
3 to 3.3	• LOOP occurs, bus voltages go to 0, MCC contactors drop out.
4 to 4.3	• UV relays* initiate load shed of 6.9kV, 4.16kV and 480V switchgear loads. • EDGs start on load shed relay actuation.
6	• Permissive for EDG breaker closure is satisfied; however, EDGs have not attained voltage and/or frequency so EDG breaker remains open.
14.0 to 14.3	• EDGs at voltage and frequency, EDG breaker closes, busses re-energized. • Component cooling water pumps start (not tripped on load shed). • Charging pumps start (not tripped on load shed). • Other LOOP loads start sequencing in accordance with design.
>14.3	• SIAS occurs, EDG breaker tripped open by SIAS resulting in bus load shed. • EDG remains at rated voltage and frequency.
>16.3	• EDG breaker recloses, busses re-energized. • Component cooling water pumps and charging pumps restart (not tripped on load shed). • SIAS-actuated MOVs start stroking. • Other LOOP/SIAS loads start sequencing in accordance with design.
>46.3	• Automatic LOOP/SIAS EDG loading ends.

* UV relays have an inherent 1 second time delay for actuation.

It should be noted that EDG breaker trip, load shed, and subsequent sequencing of LOOP/SIAS loads occurs only for a SIAS subsequent to EDG breaker closure for LOOP. In the event SIAS occurs after LOOP but before EDG breaker closure, only those loads required for LOOP/SIAS, per Table 8.3-2 in the UFSAR, are sequentially started. In either case, only those loads required to support a LOOP/SIAS are powered from the EDGs following the SIAS. Nonessential loads powered from the EDGs for a LOOP-only scenario are shed from the busses when the EDG breakers are opened by SIAS and are not reconnected to the EDGs. This prevents overload of the EDGs for a LOOP with delayed SIAS situation.

2. Double-sequencing:

   Loads supporting both LOOP and LOOP/SIAS, such as the component cooling water pumps, intake cooling water pumps, and charging pumps, will start once for LOOP, stop when the EDG breaker opens on SIAS, then restart following EDG breaker reclosure. SIAS-actuated loads such as the high pressure safety injection pumps do not start until after the LOOP occurs and only receive one start. Actions required for mitigation of a design basis event following a SIAS would commence approximately 2 seconds following SIAS. Analysis of these actions remain bounded by the analysis for a concurrent LOOP/SIAS since the additional time required for the EDGs to attain rated frequency and voltage (10 seconds) is not required for this scenario. Therefore, double-sequencing load start delays are not applicable to this scenario.

3. Multiple Motor Starts:

   As discussed above, some loads required for support of both LOOP and LOOP/SIAS, such as the component cooling pumps, intake cooling water pumps, and charging pumps, could be expected to see two starts within a short period. This is due to a sequenced start for LOOP, a stop when bus load shed occurs after the EDG breaker opens in response to SIAS, then a sequential restart for LOOP/SIAS. More frequent motor starts could result in accelerated thermal aging of the motor windings but are not considered to result in immediate motor failure.

   None of the SIAS-only actuated loads would be expected to experience multiple starts in this scenario since they would start only once after the EDG breaker recloses following the SIAS.

4. Control Logic Adequacy:

   The discussion in the response to Information Request 1.d. is also applicable to this scenario.

   One additional item of note is that the bus undervoltage/degraded voltage protection circuits are blocked during sequential loading of the EDGs. However, when the EDG breaker is tripped by SIAS, that block is reset and load shed is allowed to occur.

5. Motor Residual Voltage Decay:

   The same 2-second delay on EDG breaker reclosure as discussed in the response to Information Request 1.d. applies to a LOOP with delayed SIAS. Therefore, motor residual voltage decay is not an issue in this scenario.

6. Battery Capacity:

   Battery loading has not been specifically analyzed for this scenario. Loading would be similar to that discussed in the response to Information Request 1.d. with an additional 6 seconds (overall duty cycle of approximately 46 seconds) of control power support during the period the EDG breaker is opened and the additional load resulting from a second switchgear bus load shed, EDG breaker reclosure and sequentially closing several bus load breakers. This additional loading is not considered significant when compared to the battery 4-hour capability to support the 125VDC system for the Station Blackout scenario.

7. Motor Overload Protection:

   Motor overload protection during a degraded voltage condition has been evaluated as part of the PSB-1 degraded voltage relay setpoint calculations and is adequate. Premature trip of safety motor loads would not be expected.

8. Conclusion:

   This question requests an analysis of the LOOP/SIAS analysis using the timelines and, if it is determined that SIAS follows LOOP, provide an analysis of the electrical ECCS performance. Since a SIAS can occur at any time, rather than an analysis, it was assumed that a LOOP with delayed SIAS occurred. The timeline for the LOOP with delayed SIAS scenario is shown in Section 1 and also includes both 6.9kV and 4.16kV systems. Potential failures and consequential LOOP possibilities, similar to those for a SIAS with delayed LOOP, are discussed in Sections 2 through 7. The control system is designed to prevent overloading the EDGs by only allowing LOOP/SIAS loads to be started following receipt of the SIAS, as described in Section 1. The conclusion is that no common-mode plant-centered failures were noted that would result in disabling all four RCPs or both nuclear safety-related electrical trains simultaneously.

   It should also be noted that loss of Unit 2 with SIAS during peak grid loading would have a minimal effect on the distribution grid voltage and frequency that would not result in a LOOP condition, as analyzed in Section 8.2 of the UFSAR.

<u>NRC Request 1.d Part 3</u> If your analysis finds that the LOOP will follow ECCS actuation, the consequences of the delayed LOOP on the performance of the electrical ECCS systems should be evaluated in accordance with the previously stated concerns regarding double sequencing.

<u>FPL Response 1.d Part 3:</u>

As noted in the response to Information Request 1.d, above, loss of St. Lucie Unit 2 during peak grid loading would have a minimal effect on the distribution grid and would not result in a LOOP condition. The analysis performed by FPL Transmission and Distribution Systems shows that the switchyard voltage remains above the minimum switchyard voltage stated in UFSAR Section 8.2. Due to the analysis noted and the PSB-1 analysis of the St. Lucie Unit 2 nuclear safety-related auxiliary power distribution system, Unit 2 is not expected to experience a LOOP following an ECCS actuation. However, for the purposes of this analysis, it is assumed that an ECCS actuation with delayed LOOP occurs.

Initiation of SIAS results in all SIAS-actuated loads starting simultaneously – sequencing of SIAS loads does not occur unless there has been a LOOP and the EDG output circuit breaker is closed. SIAS also starts the EDGs; however, the EDG output circuit breakers remain open and the EDGs continue to run unloaded at full speed as long as voltage is present on the safety-related busses.

It should be noted that the time assumed for the EDGs to start and attain rated voltage and frequency is 10 seconds, as specified in the Technical Specifications. In actuality, this time is significantly less, approximately 7 seconds, as has been demonstrated during periodic testing.

As discussed above, double-sequencing of SIAS loads does not occur at St. Lucie. All SIAS-actuated loads start simultaneously with offsite power available. Loads required for accident mitigation that are normally running during plant operation continue to run. Sequencing of loads only occurs following a LOOP and EDG breaker closure. Also, noted double-sequencing consists of sequentially starting the SIAS-initiated loads on offsite power, followed by a LOOP, start of the EDGs, and re-sequencing the SIAS-initiated loads on the EDGs. The additional delay caused by the initial sequencing on SIAS may result in flow rates delayed beyond the times allowed in the UFSAR Chapter 15 accident analysis.

NRC Request 1.e: During an MSLB event, the released steam causes a decrease in the reactor coolant system (RCS) temperature. In the presence of a negative moderator temperature coefficient, the decreased RCS temperature results in a positive reactivity addition. After the reactor trip, if the resulting positive reactivity is greater than the negative reactivity from the inserted control rods and the borated water from the SI system, the core will return to criticality for an MSLB post-trip core. Since the actual time of loss of grid or main generator will vary, please demonstrate that a LOOP at any time in excess of 3-seconds will not lead to insufficient borated water from the SI system that was credited in the proposed MSLB analysis. This should account for the possibility that SI pumps may have started on normal ac sources and then lost power, as the grid or main generator disconnected, until the EDGs start and load (the double sequencing phenomenon). The double sequencing of the SI pumps will delay the time of injection of SI flow into the core and can cause a reduction in the borated water injected from the SI system.

FPL Response 1.e:

See response to RAI 1.f, below

NRC Request 1.f: Similarly, the LOOP may occur near the maximum return to power (e.g., Core Average Heat Flux = 18.25% at 305.5 seconds for the hot zero power (HZP) case presented in submittal). An RCP coastdown initiated near the time of peak heat flux would further challenge the approach to departure from nucleate boiling (DNB) Specified Acceptable Fuel Design Limits (SAFDL). FPL is requested to expand its break size sensitivity study for an MSLB initiating from zero power without a LOOP to MSLB cases with and without a LOOP for power levels initiating from both full power and HZP levels, and provide the results of the limiting cases (in terms of break sizes and the time of LOOP in excess of 3-seconds) with consideration of these two issues. The results should demonstrate that the applicable acceptance criteria in the Standard Review Plan, Section 15.1.5 are met for the MSLB analysis.

FPL Response 1.f:

As noted previously, the timing of the loss of offsite power is expected to occur in the time frame of 3 seconds to 12 seconds from the time of turbine trip. Since the limiting point in the non-limiting post-trip steamline with the loss of offsite power case occurs beyond ~600 seconds, the exact timing of the loss of offsite power will have a negligible effect on the results. In addition, if a steamline break were to occur when the plant is at HZP initial conditions, the loss of offsite power would not be a mechanistic failure as the turbine would not be on-line and cause a disturbance to the grid. Therefore, the timing of the loss of offsite power for the post-trip steamline break event, considering the loss of power to the RCPs and the effect on the delivery of borated SI flow, will not invalidate the conclusion that the post-trip steamline break with offsite

power available is the limiting case for licensing basis purposes. Note that breaks occurring from a full power condition are discussed in the response to RAI 5a.

NRC Request 1.g:. How does the 3-second delay in LOOP affect the containment MSLB analysis? Provide an analysis that shows that the design pressure, design temperature and environmental qualification envelope are not exceeded and that the response to Generic Letter 96-06 remains valid. Also, address any other effects that changes in the containment analysis may have on other licensing basis considerations.

FPL Response 1.g:

For the St. Lucie Unit 2 30% SGTP submittal, the current licensing basis assumption was not affected for this event. However, in general, offsite power is assumed to be available for containment main steam line break (MSLB) analyses. Availability of offsite power allows the continuation of reactor coolant pump and feedwater pump flow. Maintaining reactor coolant and feedwater pump flow maximizes the rate of primary to secondary heat transfer which maximizes the rate of mass/energy release. The 3-second delay prior to a loss-of-offsite power is not applicable to containment MSLB mass/energy release data.

Loss of offsite power and subsequent loss of coolant flow will reduce the rate of energy released to the containment making the containment temperature and pressure increase slower. The slower temperature rise also makes the inactive heat sinks more effective. As a result, the loss of offsite power case does not produce the limiting MSLB containment case. Adding three more seconds of delay will not change that result.

Impact on GL 96-06 Analysis

Assumptions of the Chapter 15 pre-trip steam line break analysis are independent of GL 96-06 analysis assumptions.

The Unit 2 GL 96-06 MSLB analysis for CCW voiding in the fan coolers conservatively assumes containment pressure/temperature (P/T) profiles from UFSAR Figures 6.2-9 and 6.2-10 which are based on mass and energy releases assuming offsite power is available per UFSAR page 6.2-11. Thus, the GL 96-06 analysis conservatively assumed a concurrent LOOP disrupts CCW flow in combination with the containment P/T profiles based on no LOOP. Qualitatively, were time lags of 3 seconds for a LOOP assumed, it would delay the onset of GL 96-06 fan cooler boiling, shorten the time period without CCW flow (PSL utilizes a closed loop cooling system in which CCW pumps restart in 11.5 seconds), and move the time of pump flow coast down to a period of higher containment temperature. FPL notes the Unit 2 MSLB case was well bounded by the controlling Unit 1 LOCA case and FPL's previous submittals demonstrated that closed system waterhammer analysis results were relatively insensitive to void size.

Accordingly, FPL concludes the GL 96-06 response conclusions and previously committed actions are unaffected by the Chapter 15 pre-trip steam line break analysis.

NRC Reviewer Feedback on Response 1.g:

Having reviewed the licensee's draft response, additional clarification is needed:

1. Why is the time period for loss of CCW shortened and not the same in both cases?

2. A higher starting CCW temperature would result in boiling sooner than previously predicted, but the worst case (maximum) CCW temperature should have been assumed in the analysis to begin with; was it?

3. Moving the pump coastdown to a period of higher containment temperature will cause the CCW to reach boiling in a shorter time period and potentially cause more steam to be formed, making the subsequent waterhammer event potentially more severe; though we would agree that the waterhammer peak pressure is relatively insensitive to the void size for relatively large voids.

4. FPL indicated that the MSLB case was well bounded by the LOCA case. This is what NRC acceptance is based on and the licensee needs to confirm that the LOCA case remains the bounding case using the same analytical methodology that the staff's acceptance is based on, or explain and justify any changes.

<u>FPL Supplemental Response 1.g:</u>

1. Loss of CCW flow begins with loss of power to the CCW pumps and ends with restoration of power to the CCW pumps.

   For the concurrent LOOP case: loss of CCW flow occurs at time zero. CCW pump restart will occur after a 11.5-second time period that includes time delays for SIAS, relay closures, and EDG start. Time period of CCW flow loss is ~11.5 seconds discounting flow coastdown and flow restart periods.

   For the 3-second delay in LOOP: loss of CCW flow occurs at 3 seconds. EDG start sequence is relatively unaffected as the EDG starts on SIAS (high containment pressure) prior to the 3-second delay in undervoltage. CCW pump reloading thus occurs in about the same 11.5 seconds. Time period of CCW flow loss is ~8.5 seconds discounting flow coastdown and flow restart periods.

2. Per previous submittals, the current GL 96-06 analysis assumes an initial CFC inlet CCW temperature of 100^{0}F and an outlet temperature of 102^{0}F. These temperatures bound maximum CCW parameters expected during normal (pre-accident) operation. A delay in LOOP initiation does not change these pre-event assumptions, but does affect the timing of the CCW flow transient versus the containment temperature response.

3. Moving the pump coastdown to a period of higher containment temperature will cause the CCW to reach boiling in a shorter time period and cause more steam to be formed assuming the time of CCW flow loss remains the same. The time of no CCW flow is however reduced by approximately 3 seconds in the case of a 3-second delay for LOOP. Although some void increase may be expected, per previous submittals, maximum pipe segment loads are relatively insensitive to void sizes considered in the St. Lucie analysis.

4. FPL's St. Lucie Units 1 and 2 GL 96-06 analysis assumes a concurrent DBA and LOOP. Under this design basis, the worst case event in terms of developing the maximum void size is St. Lucie Unit 1 LOCA, which bounds St. Lucie Unit 2 MSLB by a factor of 3.

   Assumptions of the Chapter 15 pre-trip steam line break analysis are, in general, different from and independent of GL 96-06 analysis assumptions. The assumptions for pre-trip steam line break analysis are set to maximize the increase in core power prior to the reactor

trip (occurring a few seconds after the initiation of a steam line break). Consistent with the typical industry DBA analysis approach, the GL 96-06 analysis assumed concurrent DBA and LOOP as the design basis event, and additionally, assumed conservative containment conditions from the containment peak pressure/temperature analysis generated assuming no LOOP. Adoption of a plant-specific 3-second LOOP within the Chapter 15 pre-trip steam line break analysis does not require use of the same assumption within the GL 96-06 response.

The GL 96-06 response conclusions and previously committed actions would be unaffected by a 3-second LOOP delay in the Unit 2 MSLB case. This conclusion was based on a review of the GL 96-06 documentation, which indicated:

- The St. Lucie Unit 2 MSLB void size was bounded by the St. Lucie Unit 1 LOCA void size by a factor of 3.
- A parametric review of void size indicated that voids 4 times the size of the bounding St. Lucie Unit 1 LOCA case would result in similar pipe segment forces.
- The GL 96-06 submittal was based on a specific analysis of the St. Lucie Unit 1 piping and support system which was extended by comparison to St. Lucie Unit 2. The St. Lucie Unit 2 piping support system is more conservatively designed than St. Lucie Unit 1 and would support a postulated increase in St. Lucie Unit 2 pipe segment forces.

GL 96-06 Summary:

FPL concludes that the GL 96-06 response conclusions and previously committed actions are unaffected by the Chapter 15 pre-trip steam line break analysis. This conclusion is based on two separate and independent logic paths:

1. FPL's licensing position for the GL 96-06 design basis is unaffected by the selection of a plant specific 3-second LOOP assumption for the pre-trip steam line break analysis. The design basis of the FPL GL 96-06 response remains based on concurrent DBA and LOOP. FPL remains on track to complete all committed GL 96-06 actions during the St. Lucie Unit 2 Cycle 15 refueling outage.
2. A reasonable review of the GL 96-06 analysis indicates a 3-second delay in the LOOP timing could increase the St. Lucie Unit 2 MSLB void size, but that even a void size increase by a factor of 12 would not adversely affect the original GL 96-06 analysis conclusions and committed actions.

NRC Request 2: In discussions with the NRC staff, FPL stated that the analysis of the potential for LOOP scenarios on the non-safety 6.9kv RCP buses indicated that the immediate loss of one 6.9 kV bus and the associated two RCPs due to plant-centered failures following a reactor/turbine/generator trip is possible as a result of a plant-centered component failure. The staff notes that the licensing report used to support the 30 percent steam generator tube plugging application credited the LOOP delay time of 3-seconds in the MSLB, Feedwater Line Break (FWLB) and locked rotor analyses.

Address the effect of the immediate loss of two RCPs due to a plant-centered component failure on the results of the analyses for MSLB, FWLB and locked rotor events in terms of

fuel failures from experiencing DNB, and confirm that the cases identified in the analyses provided in the licensing report are the limiting cases.

FPL Response 2:

Westinghouse has analyzed the MSLB event considering the immediate loss of power to two RCPs due to a plant-centered component failure, which is assumed to be the immediate failure of a 6.9 kV bus fast bus transfer. Note that the FWLB event is bounded by the MSLB as the power, which is the primary driver of the DNB results, achieved for the MSLB is significantly more limiting compared to the FWLB transient.

The current design basis for the seized rotor event analysis has the assumption of loss of offsite power at 3 seconds following the time of reactor/turbine trip when all the remaining pumps begin to coastdown. The same assumption with respect to the loss of offsite power is used in the 30% SGTP seized rotor analysis submitted in L-2003-276 to maintain the current design basis. The change in this design basis assumption to include the failure of a fast bus transfer (the immediate loss of two RCPs) was discussed with the NRC staff on November 23, 2004 and FPL is awaiting NRC response on this issue. FPL and Westinghouse have determined that the analysis of seized rotor event with the failure of a fast bus transfer produces less than 5% fuel failures, which are within the limits of dose consequence analysis. However, pending NRC feedback on this issue, the current analysis submitted in L-2003-276 will be retained as the analysis of record with 30% SGTP.

For the DNB evaluation of the full power steamline break event, the FBT failure was *conservatively assumed to occur at the time of reactor trip breaker opening.* All other assumptions for the DNBR calculation support the assumptions in the licensing report. The results of the analysis demonstrate that the DNB design basis is satisfied.

Additional detail is provided in the response to RAI 4.b.

NRC Request 3.a: The following questions are related to the response to questions 20.a and 20.b of the initial RAI:

a. Describe the model used for the analysis of the boron dilution event. Also, provide the definition for the RCS volumes of 3412 ft^3, 3712 ft^3, and 7368 ft^3 assumed in the analysis.

FPL Response3.a:

In the application of the WCAP-9272 reload methodology to the St. Lucie Unit 2 plant, the relationship for the time required to dilute to criticality is a function of a defined active RCS volume, a constant unborated dilution source, and an initial and a final boron concentration. The WCAP-9272 relationship for the time required to dilute to criticality is identical to what is currently assumed in the approved licensing basis analyses, as presented in the St. Lucie Unit 2 UFSAR. This is described in detail in Section 15.4.2.3.9.2 of the current St. Lucie Unit 2 UFSAR. In this UFSAR section, the time required to dilute from some initial boron concentration C(o) to criticality, Ccrit, is given by equation 15.4.2.3-6, where the time constant, τ, is defined by the total active RCS mass divided by the unborated dilution mass flow rate.

The following table summarizes the uncontrolled boron dilution scenarios modeled.

Mode of Operation	Coolant Forced Flow Source Reactor Coolant Pump (RCP) Shutdown Cooling System (SCS)	Supporting Technical Specification	Active Mixing Volume (Limiting Case)
Mode 1	RCP	3.4.1.1	7368.6 ft^3
Mode 2	RCP	3.4.1.1	7368.6 ft^3
Mode 3	RCP	3.4.1.2	7368.6 ft^3
Mode 4	RCP or SCS	3.4.1.3	7368.6 ft^3 (RCP) 3712 ft^3 (SCS)
Mode 5 (filled)	SCS	3.4.1.4.1	3712 ft^3
Mode 5 (drained)	SCS	3.4.1.4.2	3412.3 ft^3
Mode 6	SCS		3412.3 ft^3

The active mixing volumes are defined as follows:

7368.6 ft^3 - For cases where the reactor coolant pumps provide the forced flow (Modes 1 through 4), the active mixing volume includes the reactor vessel (excluding the upper head), hot leg, cold leg, cross-over leg, steam generator (adjusted for steam generator tube plugging), and pump volumes.

3712 ft^3 - For cases where the shutdown cooling system provides the forced flow and the vessel is not drained down (Modes 4 and 5), the active mixing volume includes only the reactor vessel (excluding the upper head) and the shutdown cooling system volumes.

3412.3 ft^3 - For cases where the shutdown cooling system provides the forced flow and the vessel is drained down (Modes 5 and 6), the active mixing volume includes those reactor volumes below the mid-plane of the reactor vessel nozzles and the shutdown cooling system.

<u>NRC Request 3.b:</u> Clarify the following statement in response to question 20.a:

The number of operating charging pumps, operable shutdown cooling system (SCS) and RCPs are all modeled consistent with the Technical Specification.

Provide a table showing the SCS and RCP assumed to be in operation for each Mode in the analysis, and confirm that the assumptions are consistent with the Technical Specification (TS) requirements.

<u>FPL Response 3.b:</u>

All modes include the cases with 1, 2, and 3 charging pumps operating, except for Mode 5 drained below the hot leg centerline, which includes only the case with 1 charging pump operable as per Technical Specification 4.1.1.2.c. SCS and RCP operability assumptions, in the scenarios modeled, are shown in the table in response to RAI 3.a above.

<u>NRC Request 4.a:</u> The following questions relate to Pre-Trip MSLB Issues:

a. At the July 2004 meeting at the NRC Headquarters (HQ), the staff stated that an MSLB with coincident LOOP (LOAC [loss-of-ac-power], at T=0 sec) would need to be evaluated. In the past, this case was always bounded by the LOAC occurring at reactor

trip breaker opening (RTBO). Since this submittal credits a 3+ second delay for LOAC, the coincident LOAC scenario now needs an evaluation. Provide justification that the Pre-Trip MSLB with coincident LOAC does not violate SAFDLs and is bounded by the case presented in the submittal.

FPL Response 4.a:

For the conditions associated with a simultaneous occurrence of a steamline break and a loss of offsite power, the reactor trip would be completed prior to cooler water from the steam generator (from either the steamline break or from effects of the flow coastdown) could reach the core, since the trip on the low RCS flow function would be initiated within the first few seconds of the event. The low RCS flow function would not be expected to be adversely affected within the first few seconds by the harsh environment created by the steamline break, primarily due to the location of the low RCS flow transmitters (see the response to RAI 4.e for further clarification). As a result, such an analysis would need to modify the moderator feedback characteristics to reflect beginning of life behavior to limit the power reductions that would naturally occur in the core from the flow coastdown. This essentially would force the limiting assumptions to match the assumptions made in the submitted loss of flow analysis. The only difference between the postulated scenario and the submitted loss of flow analysis would be the potential for additional cooling of the RCS from the steamline break over the (approximate) 4 seconds it takes to reach the limiting conditions in the loss of flow transient. However, in the analysis of the loss of flow analysis, the DNBR transient is analyzed with a conservative assumption where it does not credit any of the increase of the RCS pressure which would naturally occur from the loss of flow transient (more than 200 psi increase before 4 seconds into the transient based on Figure 5.1.14-5).

The steamline break transient analysis reaches a power level of 131% at the limiting DNBR condition. In addition, in response to the question 4.b (below), a DNBR evaluation of the same steamline break transient with a superimposed 2-pump flow coastdown is determined to still satisfy the fuel failure criterion.

An evaluation of the conditions comparing the transient described in question 4.b (below) to the postulated transient of a simultaneous LOAC with a steamline break confirms that the transient described in question 4.b (below) is clearly limiting.

NRC Request 4.b: At the July 2004 meeting at NRC HQ, the staff stated that an MSLB with Failure of a Fast Bus Transfer (FFBT) would need to be evaluated. This case results in a two-RCP coastdown at reactor/turbine trip. St. Lucie Unit 2 Updated Final Safety Analysis Report, Section 15.1.4.3 documents the MSLB with FFBT event and lists 3.7 percent fuel failure. Note that recent St. Lucie Unit 2 core reloads may not have analyzed this case since it was bounded by the MSLB with LOAC at RTBO scenario (which lists 33 percent fuel failure). With the 3+ second delay in LOAC, the new analysis exhibits no fuel failure. Therefore, the 15.1.4.3 MSLB with FFBT case may now be more limiting. The submittal does not address this case. Therefore, the staff requests that FPL submit the limiting MSLB with FFBT case clearly defining inputs and assumptions and demonstrate that this scenario does not violate SAFDL or provide an associated dose calculation.

FPL Response 4.b:

A pre-trip main steamline break (MSLB) with failure of a fast bus transfer (FFBT) would result in a 2-out-of-4 reactor coolant pump (RCP) coastdown initiated at the turbine trip. This

assumption supports a loss of offsite power with a 3-second delay following reactor trip breaker opening. The limiting pre-trip MSLB case supporting the 30% SGTP licensing amendment was re-evaluated assuming a partial loss of flow (2-out-of-4 RCP coastdown) initiated at the turbine trip. The input values and results of the DNBR calculation are summarized below:

- Initiation of Turbine Trip, seconds = 10.779
- DNB Limiting Time Step, seconds = 12.60 (no change)
- Core Pressure = 2114.94 psia (no change)
- Core Power Level = 131% of 2700 MWt (no change)
- Initial RCS Flow Rate, gpm = 347864 (minimum measured flow with a 3.84% flow uncertainty incorporated into the Revised Thermal Design Procedure (RTDP) Safety Limit (SAL) DNBR)
- Core Bypass Flow Fraction = 0.0254 (a 1.16% uncertainty in the core bypass flow fraction incorporated into the RTDP SAL DNBR)
- Core Inlet Flow, Fraction of Initial Value = 0.9021
- Core Inlet Flow Rate = 12.4302 ft/s (excluding core bypass flow)
- Flow Reduction to the Hot Assembly = 15% (no change)
- Core Inlet Enthalpy, BTU/lb_m = 520.46 (hot assemblies), 523.59 (rest of the core)
- Radial Peaking Factor (Fr) = 1.734 (including core asymmetric effect, no change)
- Axial Power Distribution (Axial Distance in Inches and Power Factor): (no change)

0.000	0.18702
3.684	0.68575
7.367	0.97250
11.051	1.10891
14.734	1.15621
18.418	1.15794
22.101	1.13279
25.785	1.09536
29.468	1.05616
33.152	1.01930
36.835	0.98689
40.519	0.95996
44.202	0.93864
47.886	0.92285
51.569	0.91246
55.253	0.90711
58.936	0.90634
62.620	0.90963
66.303	0.91702
69.987	0.92843
73.670	0.94331
77.354	0.96133

81.037	0.98234
84.721	1.00611
88.404	1.03236
92.088	1.06082
95.771	1.09115
99.455	1.12287
103.138	1.15508
106.822	1.18566
110.505	1.21161
114.189	1.22852
117.872	1.22586
121.556	1.19079
125.239	1.11057
128.923	0.95212
132.606	0.66752
136.290	0.20850

ABB-NV Minimum DNBR = 1.372

RTDP SAL DNBR = 1.32 (satisfies the 95/95 acceptance criterion)

The DNBR result demonstrates that the Condition II DNBR acceptance criterion is met for the limiting pre-trip MSLB case with FFBT.

<u>NRC Request 4.c.1:</u> Both the Pre-Trip MSLB and Feedwater Line Break (FWLB) analyses credit a 0.25-second delay between the RTBO signal and the turbine trip. Any safety grade actuation which provides a credit to mitigating the consequences of a transient must have a firm bases backed by surveillance requirements. The staff is unaware of any surveillance requirements on the link between reactor trip and turbine trip.

1) The response to the previous RAI question 13.a states: "Assuming 3.0 seconds for the loss of offsite power delay and a 0.25 second delay for the turbine is bounded by the 3.3 seconds justified for the loss of offsite power." Please clarify your position with regard to both the loss of offsite power delay being credited in your submittal (3.0 versus 3.3 seconds) and a justifiable turbine trip delay.

<u>FPL Response 4.c.1:</u>

Any safety grade actuation which provides a credit to mitigating the consequences of a transient must have a firm basis backed by surveillance requirements. Historically, the NRC has accepted the modeling of the turbine trip on reactor trip function in the safety analyses as it is considered to be anticipatory (that is, it is expected to occur) and provides no benefit to the transient response. This is justified in Chapter 15 of the UFSAR for most plants identify the turbine trip on reactor trip function as being modeled in the safety analyses. For transients initiated from a full power condition, the effects caused by the turbine trip function would be seen by the primary coolant beyond the most limiting point in the transient. Therefore, the exact timing of the turbine trip, that is, whether it occurs simultaneously with the reactor trip or at 0.25 seconds after reactor trip will not affect the results for either the pre-trip MSLB or the feedwater line break (FWLB) analyses performed.

With respect to the loss of offsite power delay, the analyses assume a time delay which supports a 3-second delay from the time of reactor trip breaker opening until loss of offsite power occurs.

<u>NRC Request 4.c.2:</u> For any situation where there is no firm basis, the analyst should select a conservative value, which is both reasonable and provides little mitigation to the transient. In past submittals, some indicated that a delay of 0 second was used when it made the event worse and others indicated that a delay of 3.0 seconds was used when it made the event worse. For both MSLB and FWLB events, discuss the impact of either a 0-second delay or a 3.0-second delay on the nuclear steam supply system response.

<u>FPL Response 4.c.2:</u>

As noted above, it is not the modeling of the timing of the turbine trip that is important to the analyses results, rather it is the timing of the loss of offsite power since this affects when the reactor coolant pumps begin coasting down. With respect to the MSLB and the FWLB events, the analyses for these events assume a loss of offsite power delay which supports a 3-second delay from the time of reactor trip breaker opening until loss of offsite power occurs.

<u>NRC Request 4.d:</u> With regard to Variable High Power - Excore Power Signal, the response to the previous RAI question 13.d.3 states that "the trip signal is only assumed to be operable for 60 seconds after the break initiation . . . ." For an inside containment break, containment would quickly experience an increase in temperature, humidity, pressure, and radiation levels (small increase due to secondary side only). This submittal credits a limited availability of this instrumentation. Please provide further information on the environmental qualification (EQ) status for harsh environment of instrumentation and cables supporting this trip function.

<u>FPL Response 4.d:</u>

As noted previously, the Variable High Power - Excore Power Signal credited in the mitigation of pre-trip inside containment steamline break cases for up to 60 seconds after break initiation, is consistent with the previous assumption used in the calculations supporting the current St. Lucie Unit 2 licensing basis analyses. The actual time where this trip is credited is less than 60 seconds. Therefore, crediting this function in the mitigation of the pre-trip inside containment steamline break cases is not a new assumption which has been made in support of the St. Lucie Unit 2 30% Tube Plugging / WCAP-9727 Reload methodology transition project nor is it considered to be a deviation from the previous licensing basis analysis assumptions.

<u>NRC Request 4.e:</u> For the inside containment MSLB and FWLB events, the new methodology credits a Low RCS Flow reactor trip function. Even though containment would quickly experience an increase in temperature, humidity, pressure, and radiation levels (small increase due to secondary side only), the submittal states, ". . . there would be insufficient time for the adverse environment to affect the setpoint modeled for the low flow trip." Please provide further information on the EQ status for harsh environment of instrumentation and cables supporting this trip function.

<u>FPL Response 4.e:</u>

For transients, such as the MSLB and the FWLB events, where an adverse environment is created, the design basis for the low RCS flow reactor trip was examined. The assumption in the current case is that the MSLB/FWLB event occurs simultaneous with the loss of offsite

power and that a low RCS flow reactor trip would occur within approximately 2 seconds. Given the location of the flow transmitters relative to the MSLB/FWLB events and based on the very short duration that the function would be required to be operable, it is concluded that the low RCS flow reactor trip function would provide the necessary protection to ensure that the design basis for these events was satisfied. Note that the use of low flow trip function for harsh environment is documented in the UFSAR Table 15.0-18c; however, no harsh environment is expected for the current case at the location of the low flow trip instrumentation.

<u>NRC Request 4.f:</u> The Combustion Engineering (CE) methodology recognizes that the decreasing temperature will produce a change in local power peaking. In past analyses, the local peaking factors have increased during this cooldown event. The response to previous RAI question 13.e lacks any quantification of this effect. Please discuss the change in methodology that allows the exclusion of temperature effects and quantify any change in power distributions.

<u>FPL Response 4.f:</u>

The changed methodology models the HZP SLB statepoint using an ANC model which is generated at nominal operating conditions (the "hot model"). The changed methodology also employs an ANC "cold model" calculation (assuming uniform moderator temperature of 325°F with ARI-WSR) for the purposes of applying a reactivity bias to account for the reactivity difference between the hot model taken to the limiting SLB statepoint and the cold model generated explicitly at the core average temperature of interest during the HZP SLB. A comparison of the core power distribution between the hot model and cold model at a uniform 325°F (the average core temperature at the SLB statepoint) at zero power with ARI-WSR, shows that, in the assembly of interest, the hot model conservatively predicts higher peaking factors than the cold model. For example, for the pre-redesigned Cycle 15 at zero power at a uniform temperature of 325°F, the relative power of the limiting assembly is 15.8, compared with 18.7 using the "hot model." A similar peaking factor difference (17.7 using the explicitly generated cold model compared with 20.6 using the hot model at cold conditions) was observed in the "simulated" Cycle 15 model (which utilized a different loading pattern) used in the preliminary analysis. The peaking factors thus would remain higher in the hot model (compared with using an explicit cold model) at the actual SLB statepoint.

In addition to these conservative peaking factors, the SLB methodology contains other inherent conservatisms, including the assumption that the worst stuck rod in terms of both reactivity and peaking factor effect on the SLB event is stuck out of the core.

<u>NRC Request 5.a:</u> The following questions relate to the Post-Trip return to power (R-t-P) MSLB:

a. The submittal follows established Westinghouse methodology in evaluating only the HZP case without LOAC. This methodology identifies several conservative aspects which it claims make HZP inherently more severe than the hot full power (HFP) case. However, for the CE fleet, the HFP case may approach and sometimes become more limiting than the HZP case. In many cases, fuel management guidelines require preserving control element assembly scram worth (N-1) greater than TS shutdown margin requirements. Further, the R-t-P case is time/path dependent, being influenced by the rates of cooldown, depletion of secondary inventory, and SI boron entry to the core. After reviewing the qualitative responses to previous RAIs, the staff is still not convinced that

the HFP case will not challenge SAFDLs for all future cycles. Therefore, the staff requests that FPL submit an HFP MSLB case clearly defining inputs and assumptions along with minimum HFP–1 scram worth and maximum power peaking factors that will be validated against future core reloads.

FPL Response 5.a:

As noted, the Westinghouse methodology evaluates the HZP steamline break case with offsite power available as the limiting analysis for a post-trip condition, as this condition maximizes the cooldown rate of the reactor coolant system. As noted before, initiation of a SLB event from hot full power to a post-trip condition would not provide a bounding condition due to a number of effects, but primarily due to the presence of decay heat, a significantly lower inventory in the steam generators, and the RCS thick metal masses. To confirm that this conclusion is applicable to the CE-designed St. Lucie Unit 2 plant, the post-trip steamline break double-ended rupture case was analyzed from a full power condition to evaluate the sensitivity of the post-trip transient. The following is a summary of the assumptions used in the evaluation of the post-trip steamline break initiated from a hot full power condition.

- Full power condition
- No decay heat modeled
- No thick metal masses modeled (other than the core)
- No Xenon
- Full power feedwater flow until feedwater isolation
- Conservative end of life reactivity feedback
- Full 6.3 ft^2 double-ended steamline break
- Shutdown margin consistent with the assumption of the most reactive stuck rod
- Most negative end-of-life reactivity feedback

The above case was analyzed from a full power condition to a post-trip condition and the result was that a return to power did not occur because of dryout of the faulted steam generator that occurred prior to minimum approach to criticality. Sufficient negative reactivity is inserted into the core via the drop of the CEAs to preclude a return to power even in the presence of a large, most negative end-of-life reactivity feedback condition. Therefore, the Westinghouse assumption that the HZP steamline break case with offsite power available is the most limiting analysis for a post-trip condition is appropriate for the CE-designed St. Lucie Unit 2 plant.

Note that the Westinghouse reload process confirms for each reload cycle that with the most reactive CEA stuck out of the core, there is sufficient reactivity in the rods to trip the reactor from a full power condition to no-load (hot zero power) conditions and ensure that the reactor is subcritical by the Technical Specification shutdown margin.

NRC Request 5.b: FPL requests a change from the current licensing basis for the timing of LOAC. The response to previous RAI question 8.e states that the accident analyses consider the possibility of the LOAC occurring "simultaneously with the pipe break," "during the accident," and "offsite power may not be lost." In the submittal and in response to RAIs, FPL provides justification that the Post-Trip MSLB without LOAC case is more limiting than Post-Trip MSLB with a coincident LOAC. However, the submittal provides no justification for

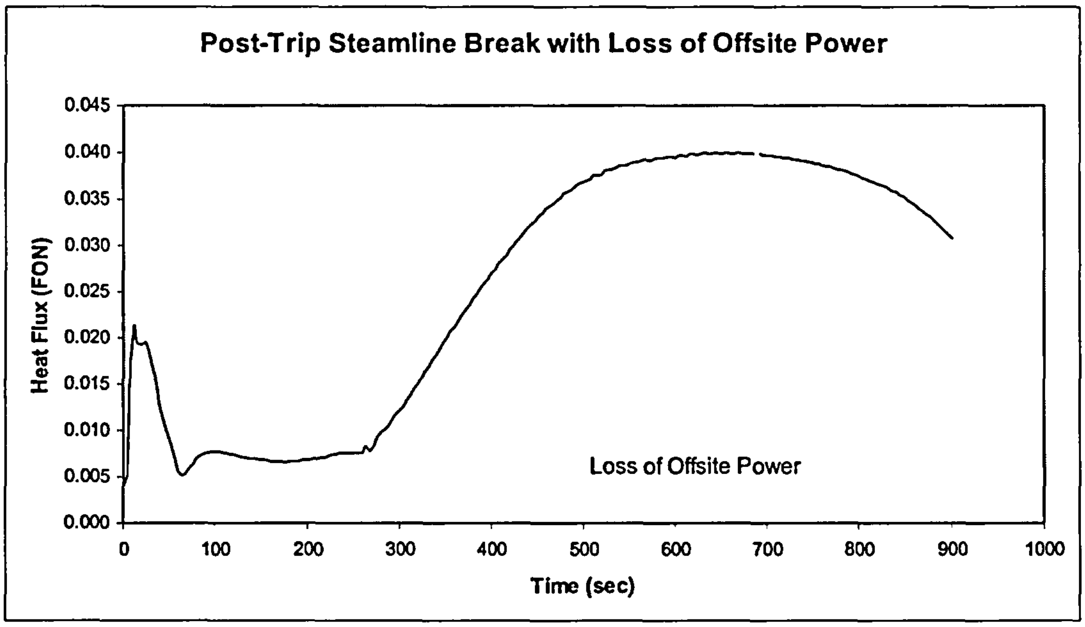
the case where LOAC occurs during the accident. The staff requests that FPL submit justification that a LOAC occurring beyond 3.3 seconds post-trip (since this time interval has been addressed separately) would not further challenge the SAFDLs. The sensitivity study should include a LOAC occurring near the peak R-t-P heat flux.

FPL Response 5.b:

As noted in the response to 5a., the steamline break from hot full power conditions analyzed to a post-trip condition did not result in a return to criticality. Therefore, the timing of the loss of offsite power beyond 3 seconds has no bearing on the results for the post-trip steamline break event. For the HZP steamline break case, which is the limiting case for a post-trip condition, the turbine is not on-line as insufficient power is generated to drive the turbine. Therefore, a reactor trip from a HZP condition is not expected to cause a disturbance on the grid which could cause a loss of offsite power to the reactor coolant pumps. However, sensitivities were run assuming that a loss of offsite power occurred at 0 seconds, 3 seconds, and 12 seconds following reactor trip. In each of these cases, the safety injection signal on a low pressurizer pressure signal occurred following the loss of power signal and within a window of 4 seconds. This is shown by the results presented in the table shown below. For the post-trip steamline break event with LOAC, the limiting point in the transient occurs around 650 seconds. It is around 650 seconds where the peak heat flux occurs, as shown in the figure, which is the limiting condition with respect to the DNB design basis. The effect of a difference in the timing of the loss of offsite power and the initiation of safety injection has essentially a negligible effect on the limiting point in the transient which, as described in Appendix A of the licensing report, is non-limiting compared to the post-trip steamline break case with offsite power available.

Sequence of Events for the Post-Trip Steamline Break with Loss of Offsite Power

Sequence of Events	Offsite Power Avail.	Loss of Offsite Power at 12 sec	Loss of Offsite Power at 3.0 sec	Loss of Offsite Power at 0.0 sec
Break occurs	0 sec	0 sec	0 sec	0 sec
Low SG Pressure SLI/FWI Signal	3.36 sec	3.36 sec	3.36 sec	3.34 sec
Low Pressurizer Pressure SI Signal	13.71 sec	13.73 sec	15.90 sec	17.42 sec
Peak Heat Flux (time of minimum DNBR)	~650 sec	~650	~650 sec	~650 sec



<u>NRC Request 6.a:</u> The following questions relate to the FWLB Event:

a. At the July 2004 meeting at NRC HQ, the staff stated that a FWLB with FFBT would need to be evaluated. This case results in a two-RCP coastdown at reactor/turbine trip. The submittal does not address this case. Therefore, the staff requests that FPL submit the limiting FWLB with FFBT case clearly defining inputs and assumptions.

<u>FPL Response 6.a:</u>

As discussed in response to previous question 18.b.1, the limiting steamline break transient would be expected to bound the effects of a feedwater line break for fuel failure and dose considerations. Refer to the response to question 4.b, above, concerning the steamline break with a 2-reactor coolant pump coastdown at reactor/turbine trip.

With respect to the licensing submittal peak RCS pressure case, a reactor trip on the low steam pressure (for RCS overpressure cases) is assumed as this occurs well after the time at which a low SG water level reactor trip would have occurred. By ignoring the low-low SG water level reactor trip, steam generator tube bundle uncovery occurs that maximizes the RCS heatup/pressurization. The licensing submittal analysis thus will bound the RCS pressure transient for the scenario where a feedwater line break trips on the low SG water level reactor trip function and is followed by the failure of the FBT.

<u>NRC Request 6.b:</u> During an inside containment FWLB event, a Safety Injection Actuation Signal (SIAS) may be generated on high containment pressure. Based on several recent submittals, the staff is now aware of a potential limiting case whereby this SIAS further challenges peak pressure and the requirements of the Three-Mile Island (TMI) Action Plan, item II.D (i.e., preclude liquid discharge from pressurizer safety valves). Specifically, all charging pumps start on an SIAS and this liquid mass addition into the RCS increases pressurizer liquid level. Coupled with a decrease in heat removal (due to the FWLB event), the pressurizer may go solid and/or liquid may be discharged from the pressurizer safety

valves. The staff does not believe that this scenario has been properly addressed for St. Lucie Unit 2. Further, the staff believes that compliance to both peak pressure criteria and TMI requirements needs to address the engineered safety features actuation system actuations, even when those actuations are not beneficial (as is the case when SIAS starts charging pumps). As such, the staff requests that the limiting FWLB scenario for peak pressurizer liquid level and TMI compliance be identified and analyzed. Clearly define initial conditions, assumptions, operator actions, and modeling techniques employed in this case. Consider the most limiting single failure (e.g. failure of steam driven or motor driven Auxiliary Feedwater pumps), a LOOP, and the potential for starting charging pumps on an SIAS on high containment pressure.

FPL Response 6.b:

St. Lucie Unit 2 TMI action plan requirements are addressed in the UFSAR Chapter 10, Section 10.4.9A. The analyses documented in this UFSAR section (which includes feedwater line break event) specifically state on pages 10.4.9A-1 and 10.4.9A-2 that nominal initial conditions are assumed for these best estimate analyses. Additionally, as stated on the UFSAR page 10.4.9A-1, Item 10.4.9A.1.c, one of the design basis requirements is to prevent lifting of the pressurizer safety valves in conjunction with the PORVs. PORVs at St. Lucie Unit 2 open at a lower pressure than the safety valves. Also, per 2-EOP-06, which will be entered on a loss of feedwater event, operators are required to maintain pressurizer level between 10 and 68%. Pressurizer fill and lifting of the safety valves under these conditions is therefore not a concern for St. Lucie Unit 2. This conclusion remains applicable for the case of 30% steam generator tube plugging (SGTP) as this event is dominated by the decay heat and the auxiliary feedwater flow. In general, a lower SGTP level results in a higher initial secondary side pressure, which when coupled with the higher heat transfer rate maximizes the initial release of mass from the secondary side, which tends to reduce the secondary side inventory. In the longer term, the total heat transfer rate from the primary side to the secondary side will be limited by the combination of SGTP and the steam generator secondary side inventory. This combination will result in this event being not very sensitive to the tube plugging levels considered in this submittal. Increased SGTP thus will not have any significant effect on the conclusions of the analysis of record.