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

FPL

January 7, 2005

L-2005-007
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
Third Request for Additional Information Supplement
WCAP-9272 Reload Methodology and
Implementing 30% Steam Generator Tube Plugging Limit

Attachment 1 is the Florida Power & Light Company (FPL) response to the third NRC request for additional information (RAI) provided to FPL by NRC email dated January 6, 2005. The supplement was requested by the NRC through a series of phone calls among NRC, FPL, and Westinghouse representatives in December 2004 and January 2005.

In response to discussions with the NRC on December 17, 2004, FPL has proposed an alternative parallel approach for review of the St. Lucie Unit 2 30% Steam Generator Tube Plugging (SGTP) proposed amendment submittal (L-2003-276). The alternative approach is based on a return to the current licensing basis assumptions relative to loss of offsite power (LOOP) timing for pre-trip main steam line break and main feed line break. These assumptions assume LOOP coincident with the reactor trip breaker opening. The appropriate revised licensing report sections for the original licensing submittal of L-2003-276 dated December 2, 2003, are provided in Attachment 2. Attachment 2 only applies to the alternative approach for the review and provides response to RAI Questions 4 and 7 as they apply to the alternative approach.

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).

The radiological consequence analyses performed in support of this proposed amendment used the alternate source term (AST) methodologies. The alternate source term (AST) methodologies were submitted by FPL letter L-2003-220 on September 18, 2003. The original intent was to have AST methodologies fully approved for St. Lucie Unit 2 prior to restart from the SL2-15 refueling outage; however, as the NRC review process progressed it became apparent that complete approval of AST would not be possible prior to the planned unit restart. During a December 17, 2004 teleconference between St. Lucie Plant management and NRC management, it was decided to focus the NRC AST review on those design basis events necessary to support restart, with NRC

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review of the other design basis events to follow at a later time. To this end, the NRC provided FPL with a list of questions via an NRC (Moroney) to FPL (Madden) e-mail dated January 5, 2005. FPL letter L-2005-004 dated January 7, 2005 formally documents the FPL response to that NRC request.

For the 30% SGTP proposed amendment, 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 response to the second NRC request for additional information (RAI) dated November 19, 2004 was submitted by FPL letter L-2004-287 on December 10, 2004. This letter provides the responses to the third RAI.

The 30% SGTP 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 the 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.

As part of the partial implementation of the AST, the reactor coolant system (RCS) operational leakage Technical Specification (TS) change (TS 3.4.6.2) that was originally submitted by FPL letter L-2003-220 dated September 18, 2003 would need to be issued as part of this amendment. Attachment 3 to this letter provides a mark up of the proposed operational leakage TS page 3/4 4-19 and a copy of the retyped TS page 3/4 4-19.

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 23, 2005 to support the reload analyses for St. Lucie Unit 2 Cycle 15 and transition to MODE 5. 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 7 day of JANUARY, 2005
by William Jefferson, Jr., who is personally known to me.

Name of Notary Public - State of Florida

George R Madden
My Commission DD318814
Expires June 17 2008

(Print, type or stamp Commissioned Name of Notary Public)

Attachment 1

Third Request for Additional Information Response

WCAP-9272 Reload Methodology and

Implementing 30% Steam Generator Tube Plugging Limit

Response to Third Request for Additiona Information
NRC E-mail dated January 6, 2005

NRC Request 1: (Jim Lazevnick)

The responses to the NRC second RAI questions 1.a and 1.b provide an analysis for the nonsafety 6.9kV system and equipment using an assumed switchyard degraded voltage of 230kV. The responses to RAI questions 1.c and 1.d on the other hand, provide an analysis for the safety-related 4.16kV system and equipment using an assumed grid breakup event that quickly sends the switchyard voltage to 0 (zero) in 3 to 3.3 seconds. Neither assumption provides an analysis of a potential worst case grid voltage condition. The responses to the four RAI questions should be repeated using an assumed sustained switchyard voltage following trip of the St. Lucie Unit 2 generator that is just above the minimum voltage that the grid surrounding the St. Lucie Plant can support without voltage collapse occurring, or just above the setting of the safety-related loss of voltage (undervoltage) relays (reflected up at the 230kV switchyard), whichever is higher.

The response to RAI question 1.d specifically should assume the switchyard voltage drops to this value and Safety Injection Actuation Signal (SIAS) actuates immediately following the trip of the St. Lucie Unit 2 generator, with delayed loss-of-offsite-power (LOOP) occurring following timeout of the degraded voltage relays. The consequences of the double energization of Emergency Core Cooling System loads and their associated vulnerabilities (identified in RAI question 1.d) that would occur as a result of the delayed LOOP should be a part of that evaluation. The following changes should be made to your treatment of those vulnerabilities in your RAI responses:

a. Provide motor manufacturer endorsement of motors that will be starting outside of their design purchase specification requirements due to degraded voltage double energization, or outside of the National Electrical Manufacturers Association MG-1 standard if the purchase specifications did not define starting criteria. If normally running loads are periodically stopped and started by a process signal they should be evaluated for degraded voltage double energization vulnerabilities.

b. Provide evaluation of potential tripping of motor overload protection (especially those with thermal memory capability such as certain electronic relays and thermal overloads on the motor control center motor starters) due to the degraded voltage double energization.

c. Evaluate the potential for overloading pump motors during the degraded voltage double energization starts with discharge valves in the open position during the second start (NUREG/CR-6538, "Evaluation of LOCA [Loss-of-Coolant Accident] With Delayed LOOP and LOOP With Delayed LOCA Accident Scenarios," Sections 2.2.8 and 7.7 provide background detail).

d. Battery loading during the degraded voltage double energization scenario should be compared to the 1-minute battery capability which is the pertinent measure to use for this high-demand situation. Immediate unavailability of the battery chargers as a result of degraded voltage following St. Lucie Unit 2 generator trip should be evaluated. Additional unavailability of the battery chargers following energization from the emergency diesel generators (EDGs) due to charger ramp-up time should be considered.

e. Evaluation of circuit breaker anti-pumping logic should consider that, typically, removal of a continuous breaker close signal during charging of the breaker closing spring will not reset the anti-pumping logic if the closing signal is reapplied prior to completion of the closing spring charging cycle.

Response 1:

1. The following discussion is to provide the additional requested information:

   The scenario under review in this case consists of a pre-existing degraded voltage on the grid with a unit trip caused by MSLB and subsequent SIAS actuation with EDG start on SIAS. Switchyard voltages are such that following transfer to the Startup transformers, the 4160V and 480V bus voltages are above the degraded voltage only relay dropout setpoints (DV relays, approx. 91.7%). Occurrence of the subsequent SIAS starts the required loads resulting in depression of the voltage and dropout of the degraded voltage with coincident SIAS relays (DV + SIAS relays, approx. 93.3%). In order to meet the conditions as noted, the switchyard voltage will be sufficiently high such that the minimum depressed bus voltages will remain above the loss of voltage relay dropout setpoints. Voltage fails to recover above the degraded voltage + SIAS relay reset setpoints (9 seconds), resulting in timeout of the relays, bus load shed, closure of the EDG breaker, and sequential restart of the SIAS loads with full voltage available for the second motor starts.

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

Time (Sec.)	Events
0-	▪ Pre-existing grid voltage degraded such that without local voltage support from U2 main generator, the switchyard voltage would drop to just above degraded voltage relay dropout setpoints. Note – Unit 1 must be assumed offline. ▪ MSLB 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.
0*	▪ SIAS occurs, SIAS–actuated loads start. These include high pressure safety injection and low pressure safety injection pumps and motor operated valves (MOVs) and other loads. ▪ Bus voltages drop below DV relay dropout setpoints due to voltage drop from starting components; relays start timing (21-second setpoint). ▪ Occurrence of SIAS causes DV+SIAS relays (9-second) to start timing since bus voltage is also below the DV + SIAS relay dropout setpoints. ▪ EDGs start on SIAS.
9	▪ DV+SIAS relays time out and initiate load shed of 4.16kV & 480V switchgear loads. 480V MCC loads drop out when bus voltage goes to zero.
7-10**	▪ EDGs attain rated voltage & frequency, however, 2-second time delay permissive for EDG breaker closure has not timed out. EDG breaker remains open

Time (Sec.)	Events
11	▪ 2-second time delay permissive for EDG breaker closure is satisfied, 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.

* Time from unit trip depends on size of main steam line break.
** Fastest time from EDG start to breaker closure, per testing, is approximately 7 seconds. Technical Specification requirement is 10 seconds maximum.

It should be noted that for the above scenario, the 6.9kV loads, consisting of the reactor cooling pumps and main feedwater pumps, automatically transfer to the startup transformers following turbine trip. Since the bus voltage remains above the 6.9kV bus loss of voltage relay setpoint and no loads are started on the 6.9kV busses due to SIAS, the voltage remains fairly constant and the RCPs and MFW pumps continue to run.

For comparison, the degraded voltage and loss of voltage relay setpoints are shown below:

		Dropout Setpoint		**Time Delay**
Relay Function	**Logic**	**V**	**%**	**(sec.)**
4.16kV Busses 2A3/2B3 DV + SIAS	2/3	3881.5 (±17.5V)	93.31% of 4160V	9 (± 0.1)
4.16kV Busses 2A3/2B3 LV	2/2	3297.0 (±17.5V)	79.25% of 4160V	1 (± 0.1)
480V Bus DV (Busses 2A5/2B5)	2/3	440.00 (± 2.0)	91.67% of 480V	21 (± 0.7)
480V Bus DV (Busses 2A2/2B2)	2/3	434.80 (± 0.8)	90.58% of 480V	21 (± 0.7)
480V Bus LV (all 480V Busses)	2/3	363.60 (± 2.0)	75.75% of 480V	1.5 (± 0.4)

DV = Degraded Voltage, LV = Loss of Voltage

In a case where the bus voltages are depressed below the 4.16kV bus loss of voltage relay setpoints during SIAS-actuated component starting, bus load shed would initiate at 1 second (instead of 9 seconds). Re-energization of the busses via EDG breaker closure would occur when the EDGs attain rated frequency and voltage at 10 seconds (maximum). Total time for loss of voltage in this case is 9 seconds (10 – 1), plus whatever sequencing time is required for each component. This case is bounded by evaluations for a simultaneous LOOP/SIAS scenario that requires 10 seconds for EDG breaker closure, plus individual component sequencing times.

a. Nuclear safety-related motors operating on the 4160V system were procured with a 75% voltage starting requirement (Ref. Section 8.3.1.1.3 of the Unit 2 UFSAR). Further evaluation of these motors for starting at a lower voltage is not required since the 4.16kV bus loss of voltage relays are set at 79.25%; therefore, motor operation at a lower voltage is prevented by bus load shed.

   Nuclear safety-related motors operating on the 480V system were procured with a 90% voltage starting rating, per NEMA MG-1, with the exception of the charging pumps, which have a 75% voltage starting rating. An existing evaluation of motor starting for the 480V loads started on SIAS has shown that there is adequate capability to start at voltages that are just above the 480V bus loss of voltage relay setpoint of 75.75%.

480V Motors	Min Req'd Terminal Voltage (@460V)	Equivalent percentage @480V	Accel. Time (Sec.)
480V Switchgear			
2HVS-4A/4B*	80%	76.67%	7
480V MCC			
2HVE-13A/13B	78%	74.75%	3.8
2HVS-1A/1B/1C/1D (Low Speed)	75%	71.87%	6.4
Boric Acid Makeup Pump 2A/2B	75%	71.87%	5
Hydrazine Pump 2A/2B	77%	73.79%	18.4
2HVE-9A/9B	78%	74.75%	11.5
2HVE-6A/6B	78%	74.75%	5.2

Therefore, it is expected that the SIAS-actuated fan and pump loads will successfully start.
The current degraded voltage calculations assume motor operated valves stall for an initial 6.5 seconds, due to low voltage, and commence valve stroke when bus voltages recover. This has been evaluated to be acceptable with respect to valve operation and motor thermal capability considerations.

b. Potential tripping of motor overload protection for running motors has already been evaluated with respect to the degraded voltage relay setpoints. The conclusion is that none of the operating motors would trip on overload at 75% voltage before the degraded voltage relays dropout.

Components listed in the table above, plus the HPSI pumps, LPSI pumps, CS pumps and charging pumps, could experience two starts within a relatively short time period. The first start for the given scenario would be at degraded voltage upon receipt of SIAS. The second start would be during sequential loading of the EDGs. There are other loads that are normally running during plant operation that also receive a SIAS start signal; these loads are not affected since they would only have one start during load sequencing on the EDGs at full voltage.

The charging pump breakers are not tripped upon load shed; however, the charging pumps would lose power for approximately 2 seconds between bus load shed and EDG breaker closure. The overload protective devices consist of a solid-state trip device on the 480V switchgear breaker. These devices do not have a "thermal memory" property and, therefore, would consider each start as an individual event and would not be expected to trip prematurely.

The four Containment Cooler Fans, 2HVS-1A/1B/1C/1D, normally operate with three fans running. Upon receipt of SIAS, the running fans switch from fast to slow speed and the idle fan starts in slow speed. Following bus load shed, all four fans start 3 seconds after EDG breaker closure (5 seconds after bus load shed). It is expected that the fans would coastdown after loss of power at bus load shed; however, the fans would still be turning when sequenced on the EDG. Therefore, since the fans would be turning when power is restored, starting current would be greatly reduced from locked rotor and thus overload trip would not be expected. Additionally, review of the control circuit shows that the thermal overload protection for slow speed operation of the containment cooler fans is alarm-only. Therefore, premature trip of the overload protection would not prevent start of any of the containment cooler fans.

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 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 are not seen as a concern for safety-related component operability. This also applies to those components that are normally controlled by automatic operations and thus may see multiple starts. It should be noted that starts at degraded voltage have reduced locked rotor current (constant-impedance motor model). Therefore, resultant heating of the motor windings would be less.

2HVS-4A/4B are the Reactor Auxiliary Building supply fans; one of which is running at all times. SIAS starts the idle fan, which has an acceleration time of 7 seconds. These are powered from 480V switchgear circuit breakers with overload (long time) protection time delay set for approximately 10 seconds. Therefore, the starting fan should accelerate to full speed at reduced voltage without tripping the overload protection. Additionally, the overload devices do not have a "thermal memory" property and, therefore, would consider each start as an individual event and would not be expected to trip prematurely.

Normal selection of thermal overload heaters results in a rated trip current somewhat higher than normal running current to prevent spurious trips during operation. Also, since motors are modeled as constant impedance during starting, the locked rotor current at reduced voltage would be less than that at rated voltage. Therefore, there is reasonable assurance that starting the 480V MCC loads at degraded voltage would not result in overload trips at degraded voltage.

The only overload devices with "thermal memory" that could cause premature trip due to two successive starts are the devices installed in the 480V MCCs. Two successive starts could reduce the overload trip time for the second start due to the residual heating of the thermal overload heater element from the first start. It should be noted that in all cases, there is some time delay before the second start that would allow for some cooling, via radiative and convective heating to the air and conductive through the copper cable connections, before the second start. The loads affected are reviewed below.

Motor operated valves actuated by SIAS are not expected to trip prematurely since the thermal overload (TOL) function is bypassed and generally provides an alarm-only function.

A review of motor characteristics, motor starting time calculations and TOL ratings for 480V MCC-powered components fans HVE-13A/13B, Boric Acid Makeup Pumps 2A/2B and fans HVE-6A/6B shows that the minimum trip time at locked rotor exceeds twice the calculated acceleration time at degraded voltage. For the given scenario, the first start is at degraded voltage, with resultant longer acceleration time and lower locked rotor current (motors modeled as fixed impedance for locked rotor). The second start would be at full voltage following EDG breaker closure, with faster acceleration time and higher locked rotor current. Therefore, it can be concluded that these components would not trip as a result of two starts in succession, one at degraded voltage and the second at full voltage.

Due to a relatively long acceleration time at degraded voltage and shorter TOL trip time at locked rotor, it is possible the Hydrazine Pumps could trip on the second start. The Hydrazine Pumps function to inject hydrazine into the suction of the CS pumps as part of the iodine removal system to enhance the containment spray system's ability to remove airborne fission products from the containment atmosphere following a LOCA or CEA ejection event. In the given scenario, containment spray may actuate due to high-high containment pressure with SIAS. However, as a LOCA or CEA ejection event is not postulated, the iodine removal function of the Hydrazine Pumps is not required. Therefore, trip of the Hydrazine Pumps in the given scenario would not affect plant response and subsequent manual reset of the TOL relay and restart of the pumps, if desired, would be acceptable.

Fans HVE-9A/9B function to reduce the spread of radioactivity within the Reactor Auxiliary Building following a Design Basis Accident/LOCA by ensuring airflow from areas of low potential radioactivity to areas of progressively higher potential radioactivity. They have an acceleration time of approximately 11.5 seconds at reduced voltage; therefore they would be almost at full speed when bus load shed occurs. Each fan is loaded on its respective EDG in the 24-second load block; therefore it would be without power for 26 seconds following bus load shed. As noted in the discussion for the Hydrazine Pumps, above, a LOCA is not postulated as part of the scenario under discussion and radiation in the Reactor Auxiliary Building is not expected to increase. Therefore, trip of the fans in the given MSLB/SIAS event would not affect plant response and subsequent manual reset of the TOL relay and restart of the fans, if desired, would be acceptable. Additionally, testing has shown that these fans have a coast-down time of greater than 90 seconds. Therefore, the fans would still be rotating when the second start occurs, resulting in a lower starting current and reduced possibility of TOL relay trip.

c. The only major pumps that start on SIAS consist of the HPSI pumps, LPSI pumps, charging pumps and Boric Acid Makeup Pumps. Starting the HP & LPSI pumps and charging pumps with discharge valves open does not affect pump start or operation since the pump discharge would be at RCS pressure; therefore, pump runout, with associated higher currents, would not occur. The Boric Acid Makeup Pumps discharge to the suction of the positive displacement charging pumps which represents a fixed hydraulic resistance; therefore, pump runout would not occur.

d. The effects on battery loading of a Station Blackout (SBO) with previous SIAS and Auxiliary Feedwater Actuation Signal (AFAS) have been addressed in the existing St. Lucie Unit 2 safety-related battery calculation. Trips of the major accident mitigation pumps (HP & LP Safety Injection, Containment Spray and Auxiliary Feedwater) were noted to occur, in addition to trip of other normally-operating loads, upon bus load shed. The conclusion reached was that the additional loading is not significant and the peak first-minute load remains below the battery procurement specification first-minute load. Also, it was determined that the worst-case battery loading scenario, with respect to battery terminal voltages, occurs during an SBO event, not the LOOP/LOCA event. This is due to the extended battery discharge period during the SBO with an assumed EDG start using the battery during the last minute of discharge.

The initial closing of switchgear breakers for accident-mitigation loads occurs upon receipt of SIAS. In the given scenario, this would occur during degraded bus voltage prior to bus load shed. It should be noted that the battery chargers are capable of operation, at reduced current, with input voltage as low as 75%. Therefore, the initial SIAS actuations would be with the battery chargers active and would not be a battery load. However, for purposes of this evaluation, it is assumed that the pre-existing degraded voltage condition results in voltages below the operating range for the battery chargers and therefore the initial SIAS actuations are considered battery loads. The SIAS actuations would be followed approximately 9-seconds later by bus load shed initiated by the degraded voltage + SIAS relays and actuation of various other DC loads. IEEE 485-1997 states: "If a discrete sequence can be established, the load for the period should be assumed to be the maximum load at any instant." Since several seconds elapse between the SIAS start of loads and subsequent LOOP and bus load shed, a discrete sequence is established. Battery loading due to bus load shed is greater than battery loading due to start of SIAS-actuated equipment. Therefore, it is not necessary to consider the total of both loads within the first minute calculation and the battery loading for this scenario is bounded by the existing calculations that assume the DC current applicable to the 4.16kV and 480V bus load shed is maintained for the entire first minute duration. Additionally, the assumption in the battery sizing calculations that breaker trip solenoid loading exists on the battery for a full minute is very conservative as each load is actually momentary (less than a second).

The effects of battery charger ramp-up are not considered significant and are bounded by the existing battery calculations that assume the battery load remains for four hours before AC voltage is restored. The battery chargers are re-energized approximately 27 seconds after EDG breaker closure. Ramp-up to full capacity would be expected before one minute has elapsed; therefore, the existing battery calculation is bounding.

e. A review of the circuit breaker internal closing circuit shows that removal of a continuous start signal at any time causes the anti-pump relay to de-energize, resulting in reclosure of its associated normally-closed contact. However, the limit switches associated with the spring charging operation would remain open until the spring is recharged and the ratchet is latched. If a breaker close signal came in before the springs are recharged and the ratchet latch check switch is closed, the breaker will not close and the anti-pump relay would energize and seal-in. This would prevent any further breaker close attempts. Spring charging occurs after breaker closure and takes approximately 6 seconds after breaker close. It can be assumed that those switchgear loads that are normally running during plant operation are not required to start for SIAS and that sufficient time has elapsed such that the springs are fully charged and all limit switch contacts closed. Therefore, the subsequent breaker closure as part of sequencing on the EDGs would not be blocked.

Switchgear breakers that closed for SIAS (e.g. LPSI pump), would be blocked from reclosing should the second breaker closure signal occur before spring recharging has completed. The initial breaker closure for SIAS-actuated components would occur at time 0 per the scenario described above. This would start the spring recharge cycle. Load shed would occur at 9 seconds, followed by bus re-energization at 11 seconds. The first switchgear breaker to sequence on the EDG is the LPSI pump at 3 seconds (Component Cooling Water Pumps and charging pumps do not trip on load shed). Therefore, a total of 14 (11+3) seconds would elapse between initial breaker closure for SIAS and the second breaker closure for sequencing on the EDG. This would provide sufficient time for the spring recharge cycle to complete and the associated limit switches to close. The conclusion is that the second breaker closure would not be blocked and the anti-pump relay would reset.

NRC Request 2:. (James Lazevnick)

Describe the interface agreement that St. Lucie Unit 2 has with its transmission system operator, to be notified of periods of inadequate post-trip switchyard voltages given a contingency trip of St. Lucie Unit 2. What is the switchyard contingency post-trip voltage value that the transmission system operator uses as the point at which to notify St. Lucie Unit 2? How does this value compare to the required switchyard voltage necessary to preclude actuation of the St. Lucie Unit 2 degraded voltage relays? How often does the transmission system operator's contingency analysis program (that is used for identification of the inadequate contingency post-trip voltages) update? How quickly is the transmission system operator required to notify St. Lucie Unit 2 operators once he learns of inadequate contingency post-trip voltages?

Response 2:

Interface agreements have been established between FPL's Power Supply Division (Transmission System Operator - TSO) and St. Lucie Nuclear Plant (NPP). The Switchyard Voltage Limit agreement specifies the minimum and maximum allowable switchyard voltages and the communication requirements when off-normal grid conditions exist. If conditions exist or are forecasted to exist where the switchyard voltage limits cannot be maintained, the Power Supply Load Dispatch Office would contact the St. Lucie Control Room and inform them of the nature of problem and expected remedial actions.

The TSO operates the grid using an on-line Contingency Analysis software program that continuously calculates the NPP switchyard voltage assuming various "contingencies" occur, such as, a plant trip or transmission line or substation fault. When the NPP switchyard voltage (actual or post-contingency) approaches the specified limits (within 1 kV), an alarm is initiated to alert the TSO to take corrective action and notify the NPP within 5 minutes. The TSO Contingency Analysis program updates every 10 minutes, worst case.

The Switchyard Voltage Agreement specifies the minimum and maximum allowable switchyard voltages. The minimum switchyard voltage is 230 kV and maximum is 244 kV when both units are connected to the switchyard via the auxiliary transformer and 241 kV maximum voltage if either unit is connected to the switchyard via the startup transformer. The nominal switchyard voltage is maintained at 240 kV. The minimum contingency voltage (i.e. unit post-trip) is maintained above the minimum 230 kV value by continuous monitoring of the Contingency Analysis program.

The minimum switchyard voltage limit is the basis for calculations to meet NRC Branch Technical Position PSB-1 "Adequacy of Station Electric Distribution System Voltages. The worst case accident loading has been evaluated assuming the minimum switchyard voltage to ensure that safety related equipment would not be damaged and would function as required when connected to offsite power. The minimum switchyard voltage will not result in degraded voltage relay actuation following a unit trip. The maximum voltage limits ensures the NPP loads are not subjected to excessive high voltages, particularly during light load conditions when the unit is shutdown.

Offsite power operability is assured by verifying correct breaker alignment and indicated power availability in accordance with Technical Specifications. Offsite power is also considered inoperable if the TSO notifies the NPP that the switchyard voltage cannot be maintained above the minimum value assumed by the PSB-1 degraded voltage analysis.

If the response to NRC Request 1 (SIAS with degraded grid) is not considered adequate, then the NRC will accept the three compensatory actions until further electrical system analysis is completed. The three compensatory actions are listed below with a brief discussion on how the actions would be implemented.

1. The St. Lucie nuclear unit operator shall contact the transmission system operator once a shift (every 12 hours) to confirm adequate voltages exist at St. Lucie to accommodate a unit trip while starting emergency loads.

   This will be implemented by adding this requirement to plant procedure OP-2-0010125, "Schedule of Periodic Tests, Checks, and Calibrations".

2. The transmission operator shall notify the nuclear plant if their contingency analysis program becomes inoperable. Upon receipt of this notification St. Lucie shall perform an operability assessment.

   This will be implemented by revising the current switchyard voltage limit agreement that specifies the notification requirements for degraded switchyard voltage. The time limit for notification will be 30 minutes to allow for normal maintenance (i.e. rebooting) of the associated computers. The switchyard voltage limit agreement will be added as an attachment to ADM-16.01, "PSL Switchyard Access/Work Control". Procedure 2-ONP-53.01, "Main Generator" will be revised to specify that an operability assessment be performed when notified by the TSO that the CA program is inoperable.

3. Subsequent to any St. Lucie reactor trips, the resultant switchyard voltages shall be verified to be bounded by the same voltages predicted by the contingency analysis program under the same conditions.

   This will be implemented by adding this requirement to plant procedure 0030119, "Post Trip Review." The post trip voltage would be compared to the worst case contingency event at the time of a unit trip.

NRC Request 3: (Paul Clifford)

The St. Lucie Unit 2 Updated Final Safety Analysis Report (UFSAR) Chapter 15 feedwater line break (FWLB) analysis requires consideration of the limiting single failure (SF). The St. Lucie Unit 2 license amendment did not include such a case. At the July 2004 meeting at the NRC headquarters (HQ), the NRC staff stated that a FWLB with failure of fast-bus-transfer (FFBT) would need to be evaluated. This scenario includes a two-reactor coolant pump (RCP) coastdown at reactor/turbine trip. In response to an RAI question 6.a, FPL stated that credit for an earlier low steam generator level (LSGL) reactor trip would ensure that the calculated peak pressure is bounded by the submitted FWLB case (which credits a low steam generator pressure trip). The NRC staff does not accept credit for a level induced trip signal. Further, the potential credit for the LSGL trip was already cited as a conservative assumption to compensate for uncertainties in the RETRAN steam generator model. In addition, regulations require that the limiting case be identified and presented in sufficient detail. As such, the FWLB with FFBT case must be fully evaluated to ensure that the acceptance criteria is met. If this case turns out to be more limiting than the case without FFBT, then the FWLB with FFBT case must be presented in the future UFSAR update. The NRC staff expect that the FWLB calculation will address:

a. Detailed sequence of events and input assumptions for the FWLB case and FWLB with FFBT case.

b. Identify limiting case and demonstrate satisfaction of acceptance criteria.

c. Justification for any delay between reactor trip and turbine trip which promotes a more benign transient.

Response 3:

In response to this RAI, Westinghouse has assumed a failure of the fast bus transfer for the FWLB event. The failure of the fast bus transfer (FFBT) is assumed to occur at the time of reactor trip breaker opening. There are no other single failures of the protection system that would result in a more limiting transient, as the event is terminated by a reactor trip.

The failure of the fast bus transfer at the time of reactor trip breaker opening results in the coastdown of two-out-of-four reactor coolant pumps. The remaining two RCPs are assumed to coastdown at 3.0 seconds following reactor trip breaker opening due to a loss of offsite power (LOOP). The analyses were performed with all of the remaining assumptions consistent with what was assumed in the St. Lucie Unit 2 30% SGTP licensing submittal. The results of these analyses are presented in Figure RAI3-1. As shown in this figure, the resulting peak RCS pressure remains well below the corresponding limit. For St. Lucie Unit 2, the applicable licensing basis RCS pressure acceptance criteria are 2750 psia (110% of the design pressure) for small feedline breaks (smaller than 0.20 ft^2) with no loss of offsite power, and 3000 psia (120% of the design pressure) for large feedline breaks (greater than 0.20 ft^2) with a loss of offsite power and/or failure of fast bus transfer. [The fast bus transfer failure occurrence frequency is estimated to be less than 1E-2.]

Table RAI 3-1 shown on the following page shows the revised time sequence of events assuming that a fast bus transfer failure occurs at the time of reactor trip breaker opening and the resulting affect on the peak RCS pressure. With respect to the criterion of the DNB design basis, the FWLB is non-limiting and would be bounded by the pre-trip steamline break event with the FFBT. Note that with no FFBT, the table (Table 5.1.12-4) presented in the St. Lucie Unit 2 30% SGTP licensing submittal applies.

With respect to secondary system overpressurization, the St. Lucie Unit 2 30% SGTP licensing submittal analysis results remain bounding with respect to the acceptance criteria identified above.

In addition, the analysis as presented includes conservatisms, without which the 110% of design pressure limit would be satisfied for the feedwater line break cases and/or a failure of the fast bus transfer. The following provides a summary of these conservatisms:

> A review of the feedwater line break analysis performed in support of the St. Lucie Unit 2 30% SGTP licensing submittal indicates that a reactor trip on the low steam generator water level would have occurred well before the low steam generator pressure trip and prevent the RCS pressure from exceeding 110% of design limit. For the limiting break size, with respect to the peak RCS pressure, there is less than 15,000 lbm of total mass (liquid and steam) in the steam generator with the large majority of this inventory being steam (>95% by volume) around the time of reactor trip on low steam generator pressure. Given that the steam generator feedring is located near the lower narrow range pressure tap, it is expected that this would be low pressure point in a FWLB event and given that there is essentially a steam generator full of steam, a low steam generator water level trip would come earlier and prevent the RCS pressure from exceeding the 110% of the design limit. Furthermore, the majority of the steam generator mass would have blown down to the containment (including any mass from the feedwater system up to the time of feedwater isolation) and thus would likely generate a containment pressure reactor trip signal. Although a specific calculation was not performed, it is expected that this reactor trip function would occur prior to the low steam generator pressure trip and prevent the RCS from reaching the 110% of design limit pressure. For breaks outside containment, an adverse environmental penalty would not have to be applied to the low steam generator pressure reactor trip function and the 110% of design limit pressure would be met with the currently assumed conditions. Therefore, based upon the above qualitative argument, the 110% of design pressure limit would be met for the feedwater line break event.

Figure RAI 3-1
Peak RCS Pressure Results for Limiting FWLB Pressure Cases

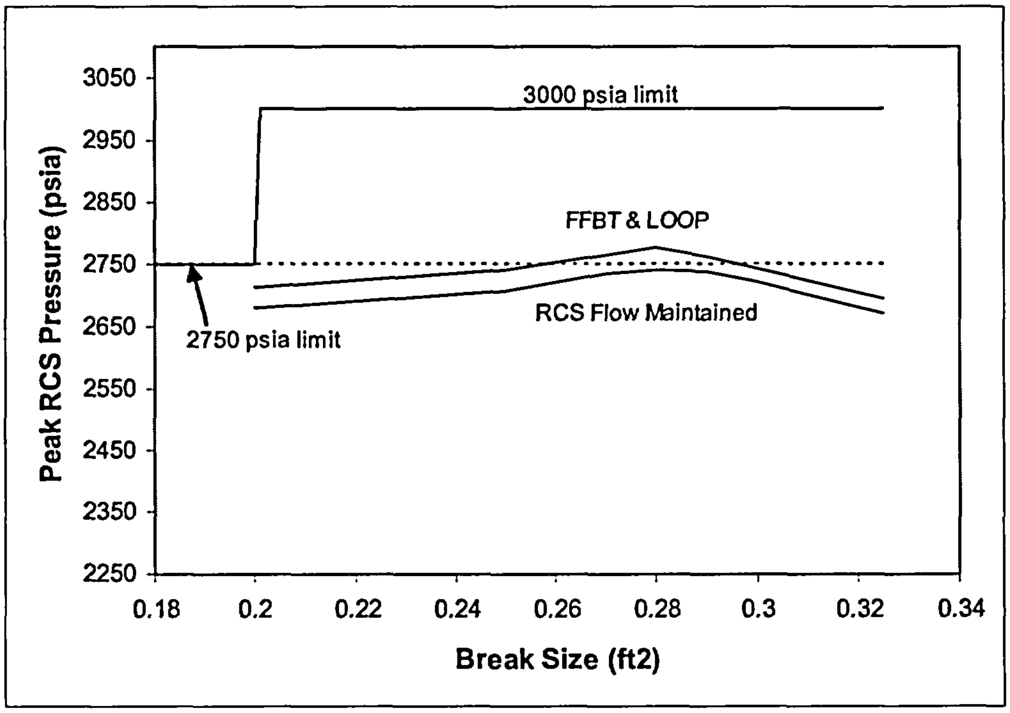


Table RAI 3-1: Sequence of Events and Transient Results for Feedwater Line Break with FFBT		
Without Pressurizer Pressure Control (for Primary RCS Overpressure)		
Event	0.20 ft^2 Time (seconds)	0.28 ft^2 Time (seconds)
Initiation of Event	0.01	0.01
Manual Feedwater Isolation (both loops)	0.01	0.01
Reactor Trip	35.2 (High Pzr Pressure)	30.4 (Low SG Pressure)
Reactor Trip (breakers open)	35.6	30.8
Failure of Fast Bus Transfer (Two RCPs coastdown)	35.6	30.8
Rod Motion Begins (0.74 seconds following breaker opening)	36.3	31.5
Pressurizer Safety Valves Open	36.0	32.4
Time of Peak RCS Pressure	38.2	33.5
Remaining Pumps Trip	38.6	33.8
Peak RCS Pressure	2712 psia	2775 psia
RCS Pressure Limit	2750 psia	3000 psia

NRC Request 4: (Paul Clifford)

During a recent review in support of a Waterford Unit 3 Extended Power Uprate application, the NRC staff acquired a better understanding of a previously unanalyzed condition potentially related to the FWLB event. During an inside containment (IC) FWLB event, an SIAS may be generated on high-containment pressure. Since all charging pumps start on an SIAS, the potential exists that the mass addition due to the charging pumps may exacerbate the transient. The NRC staff has concerns that during an IC FWLB event, the St. Lucie Unit 2 Emergency Operating Procedures (EOPs) may not be adequate to instruct the operators to limit the charging flow. In response to RAI question 6.b, FPL cited 2-EOP-06, "which will be entered on a loss of feedwater event." Please discuss the EOP actions to mitigate the reactor coolant system (RCS) fill-up in the event that a SIAS is generated during an IC FWLB.

Response 4:

In accordance with the current licensing basis, the feedwater line break scenario analyzed in the UFSAR Section 10.4.9A would not result in lifting the pressurizer safety valves (PSVs) in conjunction with the power operated relief valves (PORVs), as the PORVs have opening setpoint lower than that of the PSVs. For a feedwater line break scenario, based on the indications available, operators would enter 2-EOP-05 (Excess Steam Demand). However, either of the procedures, 2-EOP-05 (Excess Steam Demand) and 2-EOP-06 (Total Loss of Feedwater), would require operators to maintain pressurizer level below 68%. In the event of a SIAS, pressurizer level would be controlled not to exceed 68% by controlling charging and HPSI throttling to prevent pressurizer from going solid. Pressurizer fill is thus not a concern.

NRC Request 5: (Paul Clifford)

The UFSAR Chapter 15 Pre-Trip Main Steam Line Break (MSLB) analysis requires consideration of the limiting SF. The St. Lucie Unit 2 license amendment did not include such a case. At the July 2004 meeting at NRC HQ, the NRC staff stated that an MSLB with FFBT would need to be evaluated. This scenario includes a two-RCP coastdown at reactor/turbine trip. In response to RAI question 4.b, FPL stated that the MSLB with FFBT case was more limiting than the MSLB with coincident loss of ac power (LOAC) case and the MSLB with delayed LOAC case. FPL provided a departure from nucleate boiling ratio (DNBR) evaluation based upon the transient minimum DNBR conditions (from the docketed case) with a superimposed two-RCP coastdown. Regulations require that the limiting case be identified and presented in sufficient detail. As such, the MSLB with FFBT case must be fully evaluated to ensure that the acceptance criteria is met. If this case turns out to be more limiting that the case without FFBT, then the MSLB with FFBT case must be presented in the future UFSAR update. The NRC staff expect that the MSLB calculation will address:

a. Detailed sequence of events and input assumptions for the MSLB with coincident LOAC case, MSLB with FFBT case, and MSLB with delayed LOAC case.

b. Identify limiting case and demonstrate satisfaction of acceptance criteria.

c. Justification for any delay between reactor trip and turbine trip which promotes a more benign transient.

d. If a superimposed, composite case is being pursued, justify the two-pump flow characteristics and demonstrate that the composite case bounds the more realistic scenarios.

Response 5:

In response to the above RAI, the following pages present the detailed information on the composite full power steamline break with the failure of the fast bus transfer at a time consistent with turbine trip. The justification for the composite case is primarily based on the fact that the reactivity feedback due to the pumps coasting down would tend to reduce the core power. This benefit is not credited since the full power steamline break and the coastdown of two RCPs were treated as separate events. In addition, the axial power shape used in the DNB analysis was skewed towards the top of the core, which is conservative for DNB considerations, whereas the axial power shape used for the insertion of the trip reactivity was severely skewed towards the bottom of the core at the time of reactor trip. This is worth a considerable amount of DNB margin. This combined with the fact that the steamline break, which is a Condition III/IV event is analyzed to Condition II criteria, demonstrates that the DNB design basis is satisfied.

Pre-Trip Steam System Piping Failure With Failure of the Fast Bus Transfer

Accident Description

A rupture in the main steam system piping from an at-power condition creates an increased steam load, which extracts an increased amount of heat from the RCS via the steam generators. This results in a reduction in RCS temperature and pressure. In the presence of a strong negative moderator temperature coefficient, typical of end-of-cycle life conditions, the colder core inlet coolant temperature causes the core power to increase from its initial level due to the positive reactivity insertion. The power approaches a level equal to the total steam flow. Depending on the break size, a reactor trip may occur due to overpower conditions or as a result of low steam generator pressure.

The purpose of this section is to describe the analysis of a steam system piping failure occurring from an at-power initial condition and to demonstrate that core protection is maintained prior to and immediately following reactor trip. The analysis assumes the failure of a fast bus transfer to switch the power for two of the reactor coolant pumps at the time of turbine trip resulting in the pumps coasting down. This event is analyzed to demonstrate that the ANS Condition II acceptance criteria, specifically the DNB design basis, are satisfied for this event.

Method of Analysis

The analysis of the steamline rupture is performed in the following stages:

The RETRAN code (References 1 and 2) is used to calculate the nuclear power, core heat flux, and RCS temperature and pressure transients resulting from the cooldown following the steamline break.

The RETRAN code is also used to calculate the primary flow coastdown following reactor trip as a result of the fast bus transfer failure, which results in two-out-of-four of the reactor coolant pumps coasting down.

The core radial and axial peaking factors are determined using the thermal-hydraulic conditions from the transient analysis as input to the nuclear core models. The VIPRE code (see Section 4.2) is then used to calculate the DNBR for the limiting time during the transient.

This accident is analyzed with the revised thermal design procedure. Plant characteristics and initial conditions are provided in Table 5.1.0-2 of the St. Lucie Unit 2 30% SGTP licensing submittal.

The following assumptions are made in the transient analysis:

1. Initial Conditions – The initial core power, reactor coolant temperature, and RCS pressure are assumed to be at their nominal full-power values. The full-power condition is more limiting than part-power in terms of DNBR. The RCS minimum measured flow is used. Uncertainties in initial conditions are included in the DNBR limit as described in Reference 3.

2. Break size – The limiting break size of 3.2 ft^2 is analyzed and trips on the Variable High Power - ΔT reactor trip function.

3. Break flow – In computing the steam flow during a steamline break, the Moody curve (Reference 4) for fL/D = 0 is used.

1. Reactivity Coefficients – The limiting break size is analyzed with a 0.30 Δk/gm/cc moderator density coefficient (MDCs) and otherwise assumes end-of-cycle reactivity feedback coefficients with the minimum Doppler power feedback to maximize the power increase following the break.

5. Protection System – This analysis only considers the initial phase of the transient initiated from an at-power condition. Protection in this phase of the transient is provided by a reactor trip, as discussed in Item 2, above.

6. Fast Bus Transfer - This analysis assumes a failure of the fast bus transfer for one of the two 6.9 kV busses causing two-out-four of the reactor coolant pumps to coastdown. This two pump coastdown is used along with the pre-trip steamline break statepoints for power, pressure and temperature to determine the resulting DNBR, as calculated by the VIPRE code.

7. Control Systems – The results of the analysis would not be more severe as a result of control system actuation. Therefore, their effects have been ignored in the analysis. Control systems are not credited in mitigating the effects of the transient.

Results

The time sequence of events for the limiting case discussed above is shown in Table A.

Conclusions

A detailed analysis to assess both the minimum DNBR and the peak linear heat rate was performed using radial and axial core peaking factors based on the statepoints generated from the limiting case. Because the radial and axial peaking factors are dependent on the cycle-specific loading pattern, the minimum DNBR and peak linear heat rate are verified to meet their respective limits on a cycle-specific basis through the WCAP-9272 reload process. The initial analysis supporting the implementation of the WCAP-9272 reload process for St. Lucie Unit 2 concludes that both the DNB design basis and the peak linear heat rate limit are met for the limiting case. Although the steamline break accident is classified as an ANS Condition III or IV event, the analysis demonstrates that the acceptance criteria for an ANS Condition II event are satisfied for all ruptures occurring from an at-power condition.

In addition, the conclusions in the original licensing report Section 5.1.5 that the DNB design basis is satisfied apply to cases where offsite power is maintained and therefore continues to satisfy Condition II criteria and bound the Condition II events of Sections 5.1.2 (Inadvertent Opening of Steam Generator Safety Valve/Atmospheric Steam Dump) and 5.1.4 (Increase in Main Steam Flow).

For responses to NRC Requests 5.c and 5.d, see response to NRC Request 9 for analysis conservatism's.

References

1. WCAP-14882-P-A, Rev. 0, *RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses*, April 1999.

2. EPRI NP-1850-CCM, Rev. 6, *RETRAN-02-A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems*, December 1995.

3. WCAP-11397-P-A, *Revised Thermal Design Procedure*, April 1989.

4. Moody, F. S., *Transactions of the ASME Journal of Heat Transfer*, Figure 3, page 134, February 1965.

Table A
Steamline Break Analysis Sequence of Events

Event	Time (sec)	Value
MSLB Transient Initiated	0.01	
Variable Overpower – ΔT Power Setpoint Reached	10.13	112.2 %
Reactor Trip Signal Generated	10.53	0.40 sec. delay from setpoint
Turbine Trip on Reactor Trip	10.78	0.25 sec. delay from reactor trip
Fast Bus Transfer Failure Occurs - Two RCPs Coastdown	10.78	FFBT assumed prior to breaker opening
CEA Release	11.27	0.74 sec. delay from reactor trip
Minimum DNBR Reached	12.60	1.372
Safety Analysis Limit DNBR (SAL DNBR)	N/A	1.32[1]
Peak Linear Heat Rate Reached	12.60	21.23 kW/ft
Peak Heat Flux Reached	12.60	131.0 %
Loss of Offsite Power/RCP Trip - Remaining Two RCPs Coastdown	13.78	3.0 sec delay from turbine trip

1 The SAL DNBR of 1.32 meets the 95/95 DNB design criterion.

Pre-Trip Steam System Piping Failure with Coincident Loss of Offsite Power

Accident Description

The purpose of this section is to describe the analysis of a steam system piping failure occurring from an at-power initial condition coincident with a loss of offsite power.

- The rupture in the main steam system piping from an at-power condition creates an increased steam load, which extracts an increased amount of heat from the RCS via the steam generators. This results in a reduction in RCS pressure and reduction of primary side steam generator and cold leg temperatures. If the rupture occurs inside containment, the adverse environment is considered for their effects on protection system setpoints.

- The loss of offsite power simultaneous with the steam system piping failure results in the coastdown of all reactor coolant pumps. With the reactor at power at the time of the accident, the immediate effect of loss-of-coolant flow is a rapid increase in the coolant temperature in the core. This increase could result in DNB with subsequent fuel damage.

Method of Analysis

The analysis rupture is performed in the following stages:

The RETRAN code (References 1 and 2) is used to calculate the nuclear power, core heat flux, the primary flow coastdown as a result of the loss of offsite power, and the RCS temperature and pressure transients.

The VIPRE code (see Section 4.2) is used to calculate the DNBR for the limiting time during the transient.

This accident is analyzed with the revised thermal design procedure. Plant characteristics and initial conditions are the same as those provided in Table 5.1.0-2 of the St. Lucie Unit 2 30% SGTP licensing submittal for the complete loss of forced flow case.

The following assumptions are made in the transient analysis:

Initial Conditions – The initial core power, reactor coolant temperature, and RCS pressure are assumed to be at their nominal full-power values. The full-power condition is more limiting than part-power in terms of DNBR. The RCS thermal design flow of 335,000 gpm is used. Uncertainties in initial conditions are included in the DNBR limit as described in Reference 3.

Break size – A break size of 6.3 ft^2 is analyzed.

Break flow – In computing the steam flow during a steamline break, the Moody curve (Reference 4) for fL/D = 0 is used.

Reactivity Coefficients – A conservatively large absolute value of the Doppler-only power coefficient is used, along with the most-positive MTC limit for full-power operation (0 pcm/°F). These assumptions maximize the core power during the initial part of the transient when the minimum DNBR is reached and is used in this analysis since the cooler water from the steam piping rupture does not have sufficient time to result in a core water density increase prior to the reactor trip.

Power Shape – A limiting DNB axial power shape (top peaked) is assumed in VIPRE for the calculation of DNBR. This shape provides the most limiting minimum DNBR for the loss-of-flow events. In the RETRAN analysis, a conservative (bottom peaked) trip reactivity worth versus rod position was modeled in addition to a conservative rod drop time (2.341 seconds from release to full insertion).

Trip Reactivity – A conservatively low trip reactivity value (5.4-percent $\Delta\rho$) is used to minimize the effect of rod insertion following reactor trip and maximize the heat flux statepoint used in the DNBR evaluation for this event. This value is based on the assumption that the highest worth RCCA is stuck in its fully withdrawn position.

Protection System – This analysis only considers the initial phase of the transient initiated from an at-power condition. Reactor trip is provided by a low RCS flow setpoint of 87.9% of the total flow and includes harsh environmental error effects of 4%.

This analysis assumes that a loss of offsite power occurs concurrent with the steamline break event causing the four RCPs to coastdown. The statepoints from this case, that is, power, pressure, temperature and RCS flow are used to determine the resulting DNBR, as calculated by the VIPRE code.

Control Systems – The results of the analysis would not be more severe as a result of control system actuation. Therefore, their effects have been ignored in the analysis. Control systems are not credited in mitigating the effects of the transient.

Results

The time sequence of events for the limiting case discussed above is shown in Table B. Figures RAI 5-1 through RAI 5-6 provide RETRAN transient plots for this event.

Conclusions

The DNBR analysis determined that there is less than 2.5% of the rods-in-DNB, which is less than the value assumed in the radiological dose evaluation submitted in L-2003-220.

For St. Lucie Unit 2, when DNB is determined to occur in the analysis of any Condition III or IV event, the potential effects of DNB propagation are evaluated using the same process used in the current licensing basis. This evaluation has concluded that DNB propagation will not lead to more rod failures than those calculated due to DNB for this event.

References

1. WCAP-14882-P-A, Rev. 0, *RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses*, April 1999.

2. EPRI NP-1850-CCM, Rev. 6, *RETRAN-02-A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems*, December 1995.

3. *WCAP-11397-P-A, Revised Thermal Design Procedure*, April 1989.

4. Moody, F. S., *Transactions of the ASME Journal of Heat Transfer*, Figure 3, page 134, February 1965.

Table B
Steamline Break Coincident With a Loss of Offsite Power Sequence of Events

Event	Time (sec)	Value
MSLB Transient Initiated and Loss of Offsite Power (All RCPs begin to coastdown)	0.01	
Low Flow Reactor Trip Setpoint Reached	1.26	87.9% of Tech Spec Flow
Reactor Trip	1.66	0.40 sec. delay from setpoint
CEA Release	2.40	0.74 sec. delay from reactor trip
Minimum DNBR Reached	3.90	Safety Analysis Limit (SAL) DNBR of 1.39. Any fuel rods with DNBR < SAL DNBR are assumed to fail

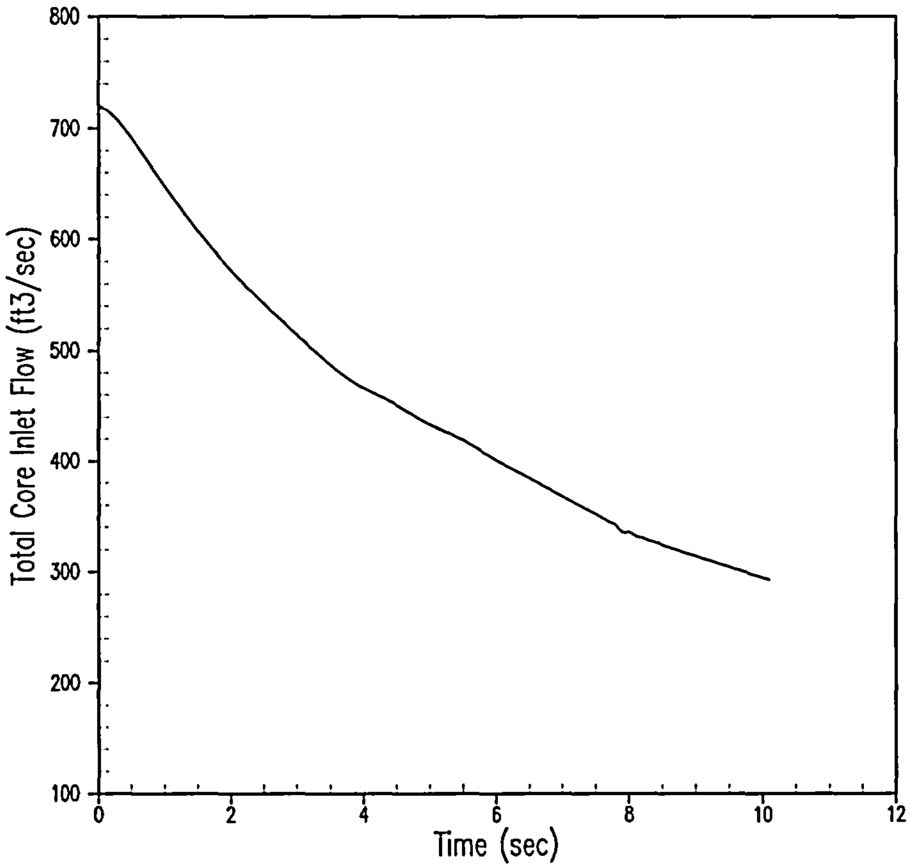


Figure RAI 5-1
Core Flow for Pre-Trip Steam System Piping Failure with Coincident Loss of Offsite Power

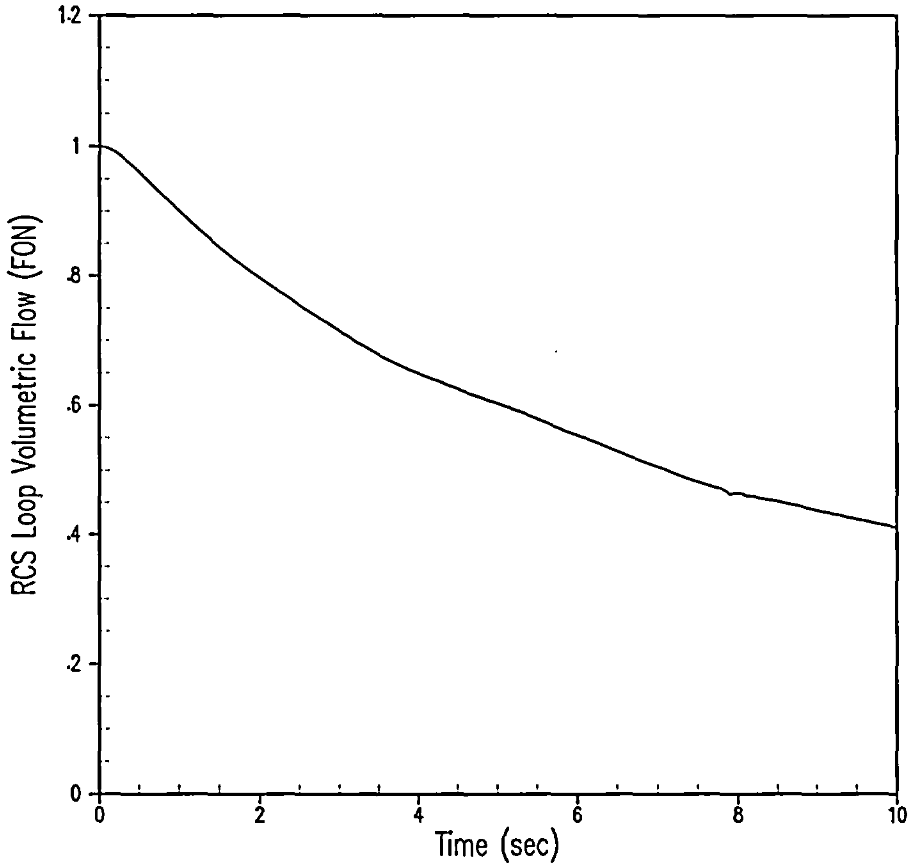


Figure RAI 5-2

Loop Flow for Pre-Trip Steam System Piping Failure with Coincident Loss of Offsite Power

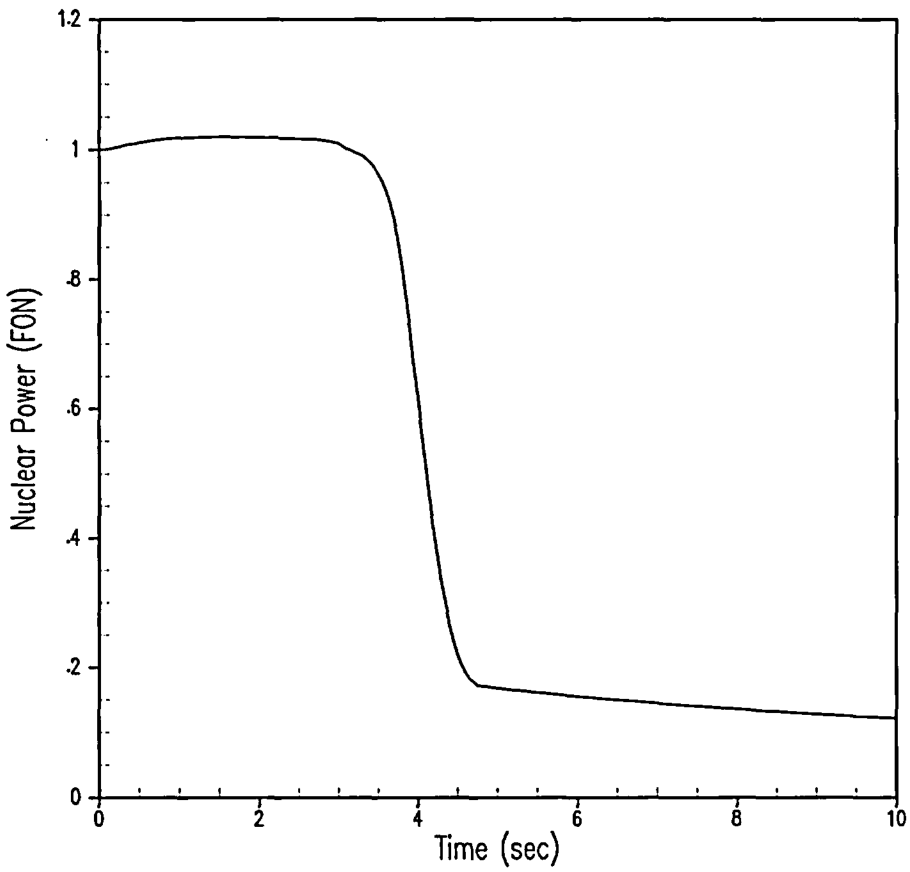


Figure RAI 5-3
Nuclear Power for Pre-Trip Steam System Piping Failure with Coincident Loss of Offsite Power

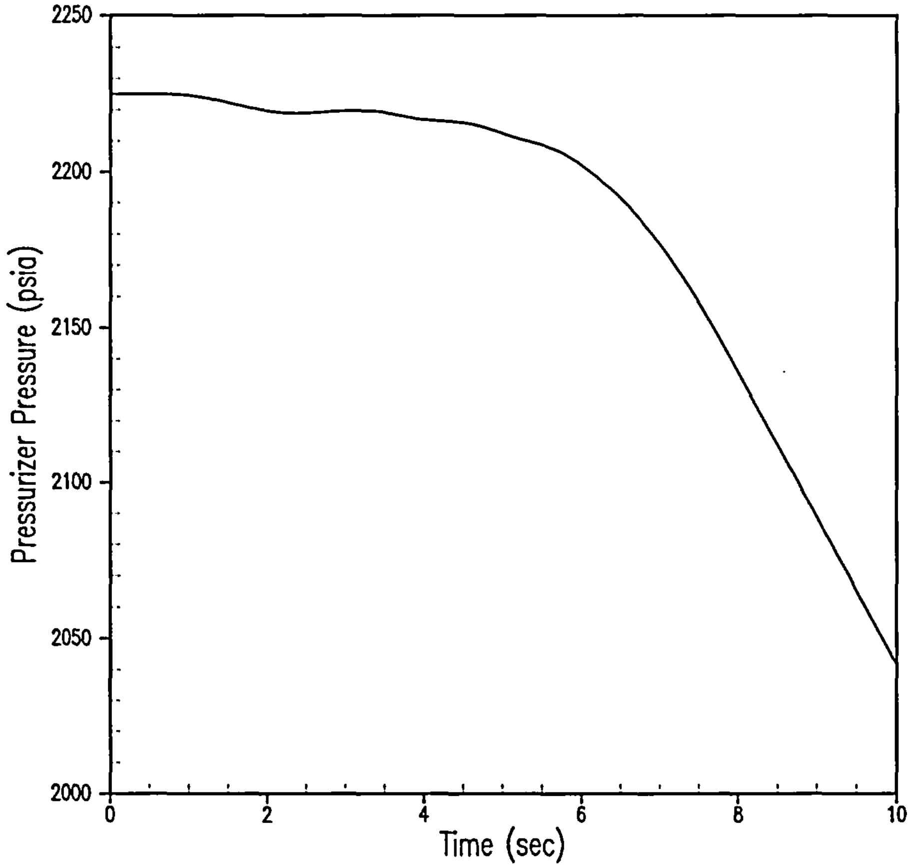


Figure RAI 5-4
Pressurizer Pressure for Pre-Trip Steam System Piping Failure with Coincident Loss of Offsite Power

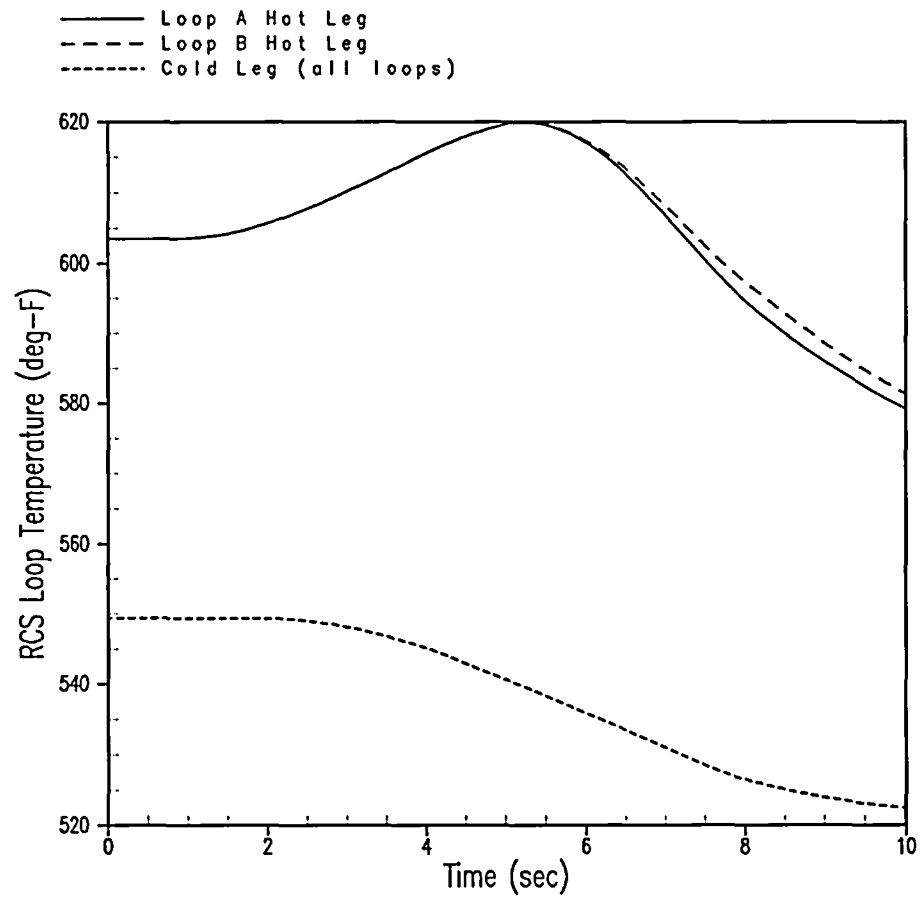


Figure RAI 5-5
RCS Loop Temperatures for Pre-Trip Steam System Piping Failure with Coincident Loss of Offsite Power

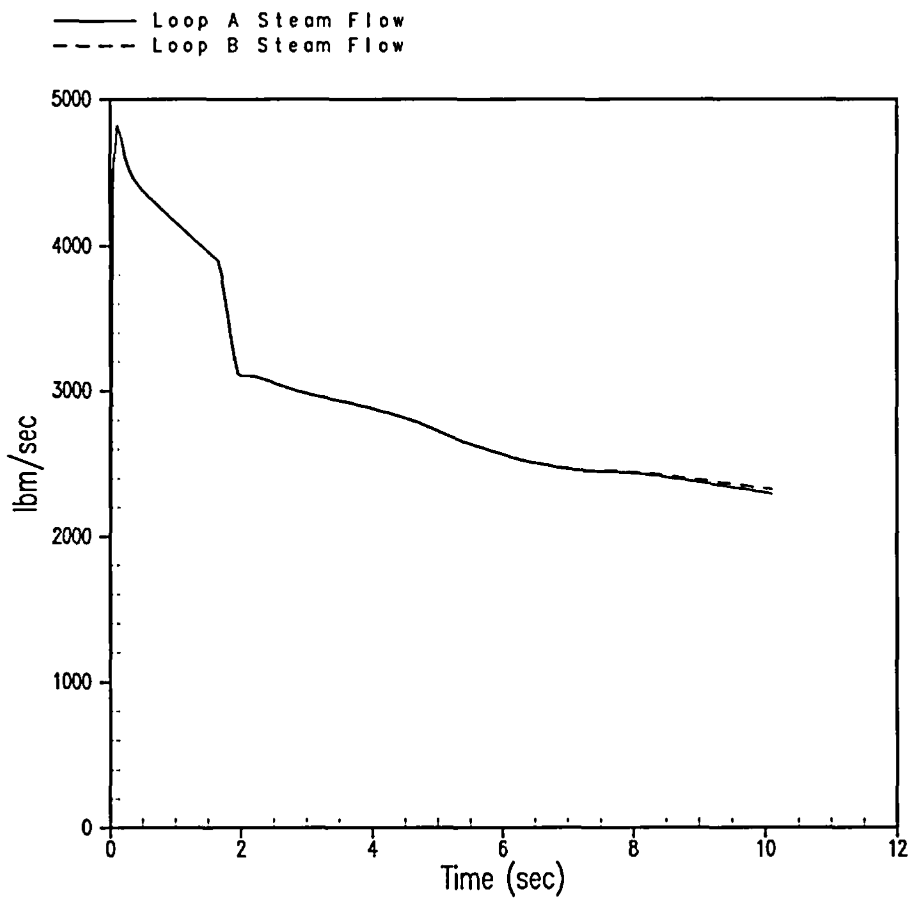


Figure RAI 5-6
Steam Generator Steam Flow for Pre-Trip Steam System Piping Failure with Coincident Loss of Offsite Power

NRC Request 6: (Paul Clifford)

The NRC staff issued RAI questions 4.d and 4.e, regarding the environmental qualification (EQ) status of the excore power and low RCS flow instrumentation and cables, respectively. These reactor trip signals are credited for the IC MSLB scenario and any delay in their response would promote more severe departure from nucleate boiling degradation during the event. For an IC high energy line break, the containment environment would quickly experience an increase in temperature, humidity, and pressure. FPL relies upon a limited operability of these instruments. Further, no harsh environment effects are included in the low RCS flow trip setpoint. The NRC staff position is that these instruments need to be qualified for 1 hour beyond any actual time credited, this position is consistent with NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment," Rev. 1.

a. Detail the EQ status of the instruments and cables associated with the excore power and low RCS flow trip functions.

b. Justify the deviation from UFSAR Table 15.0-18c whereby no harsh environmental effects are included in the low RCS flow analytical setpoint.

Response 6:

<u>The environmental qualification status of the Unit-2 RCS low flow channels may be summarized as follows:</u>

1. All in-containment portions of the RCS low flow channels (PDT-1111A,B,C,D & PDT-1121A,B,C,D) are on the EQ list and are fully qualified for post-accident harsh conditions.

2. The RCS low flow channels utilize Rosemount model 1154HH6 transmitters, Namco model EC210 conduit seals, and Kerite cable.

3. The environmental qualification of transmitters PDT-1111A,B,C,D and PDT-1121A,B,C,D is documented in the EQ Doc Pac. The qualification reflects the full containment DBA temperature/pressure profiles (peak temperature 420^0F, peak pressure > 44 psig) and an operating time of ≥180 days.

4. Similarly, the environmental qualification of the conduit seals and in-containment cable associated with transmitters PDT-1111A,B,C,D and PDT-1121A,B,C,D is documented in the EQ Doc Pac.

For steamline breaks with concurrent loss of offsite power (at time =0 seconds), the low flow trip signal will occur within approximately 2 seconds. The peak temperature/ pressure for worst steamline breaks occur at times beyond 15 seconds.

<u>The environmental qualification status of the Unit 2 linear power range UIC excore detectors may be summarized as follows:</u>

1. In accordance with Combustion Engineering Specification, the Westinghouse model WL-24131 UIC detectors are qualified for a maximum normal operating temperature of

250^{0}F. They are also qualified for a post accident operating time of 10 minutes in a DBA temperature/pressure profile with a peak temperature of 370^{0}F and a peak pressure of 60 psig.

2. In accordance with the design drawings, all in-containment connectors associated with the UIC excore detectors are covered with Raychem heat shrink tubing.

3. In accordance with the design drawing, the in-containment cable associated with the UIC excore detectors is qualified for the MSLB environment. Rockbestos type RSS-6-111 cable is used for this application, and its qualification is documented in the EQ Doc Pac.

The use of excore power instrumentation for 30% SGTP analysis is consistent with the current design basis assumption used in the current analysis of record documented in the UFSAR.

<u>Harsh Environment uncertainty for low flow trip transmitters:</u>

The following quantifies the post-accident uncertainty of RCS Low Flow transmitters PDT-1111A,B,C,D and PDT-1121A,B,C,D following an in-containment MSLB:

1. The subject transmitters are mounted on open instrument racks located near the steam generator cubicle walls on floor elevation 62 feet (the uppermost containment floor elevation or operating floor). Based on this location, no credit is taken for pressure/temperature profile mitigation or delay effects due to building geometry.

2. The subject transmitters are Rosemount model 1154HH6 instruments. All transmitter accident uncertainty effects are taken from revision AA (June 1999) of Rosemount Bulletin 00813-0100-4631 "Model 1154 Series H Alphaline Nuclear Pressure Transmitter."

3. The accident radiation effect is specified as +/- (0.25% URL + 0.75% Span) during the first 30 minutes. The Upper Range Limit (URL) for a range code 6 transmitter is 100 psid, and the span of the RCS Low Flow channels is 50 psid. Therefore, the 30 minute accident radiation effect for the RCS Low Flow channels is: +/- 1.25% Span. Use of this specification is very conservative since the transmitter accumulated dose in first 3 seconds of the accident would be insignificant.

4. The accident pressure/temperature effect is specified as +/- (1% URL + 1.0% Span) during the first 24 hours. The upper range limit (URL) for a range code 6 transmitter is 100 psid, and the span of the RCS low flow channels is 50 psid. Therefore, the 24-hour accident pressure/temperature effect for the RCS low flow channels is: +/- 3.0% Span. Use of this specification is very conservative since the temperature change experienced by the electronic circuits internal to the transmitter housing during the first 3 seconds of the accident would be insignificant.

5. The accident radiation and pressure/temperature effects are random and independent. Therefore, square root sum of squares (SRSS) methodology is appropriate for combination of these effects. The combined transmitter accident effect is SRSS (1.25% + 3.0%), which equals +/- 3.25% Span or 1.63 psid.

1.63 psid is conservatively correlated to the RCS flow to be equivalent to less than 4% of the new TS RCS flow of 335,000 gpm.

Using an additional penalty of 4% for the harsh environment effect to the analytical normal low flow trip value of 91.9%, the harsh environment low flow trip value becomes:

$$91.9\% - 4\% = 87.9\%.$$

NRC Request 7: (Paul Clifford)

This question is related to RAI question 5.a. In past reloads, the MSLB *initiated from* hot-full-power (HFP) conditions was as limiting as the case initiated at hot-zero-power (HZP) conditions. The St. Lucie Unit 2 license amendment did not include such a HFP case. At the July 2004 meeting at NRC HQ, the NRC staff requested that FPL submit the limiting HFP case so that the NRC staff would be convinced that it was no longer limiting relative to the HZP case. The NRC staff expect that the MSLB calculation will address:

a. Comparison between the UFSAR analysis of record case and the new HFP MSLB case.

b. Detailed sequence of events and input assumptions for the HFP MSLB case.

c. Comparison between cycle-specific scram worth and shutdown margin (SDM) assumed in the case.

   i. Reload Process confirmation of scram worth.

   ii. Comparison between SDM requirements assumed in analysis and St. Lucie Unit 2 operating procedures for ensuring compliance to Technical Specification SDM.

Response 7:

Historically, Westinghouse has not analyzed the full power steamline break (SLB) to a post-trip condition, as it is bounded by the post-trip steamline break initiated from hot zero power conditions. As stated previously, a SLB event from hot full power to a post-trip condition is not a limiting condition due to a number of effects, including the presence of decay heat, a significantly lower inventory in the steam generators and the energy stored in the RCS thick metal mass. However, *in response to this RAI, the event was analyzed to demonstrate that it is* indeed non-limiting. The event was analyzed with the following assumptions.

- Full power initial condition
- No decay heat
- No metal masses other than the core and steam generator tubes
- 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

The above case was analyzed from a full power initial condition for the post-trip transient. The result was that the reactor did not return to a critical condition. Sufficient negative reactivity is inserted into the core via the drop of the CEAs to preclude a return to criticality. The tables on the following pages present the input assumptions and a detailed time sequence of events used in the UFSAR analysis of record (AOR) and those used in the analysis performed in response to the RAI. This is followed by plots for the core heat flux, core temperatures, RCS pressure, SG pressure, and reactivity. A brief discussion on differences in the UFSAR plots versus the RAI analysis plots is also provided.

Regarding the question on the scram worth and shutdown margin, the following is presented. The Westinghouse safety analyses can model either the insertion of a total minimum scram worth or the Technical Specification shutdown margin. The scram worth needed to establish the Technical Specification shutdown margin is based on:

- the reactivity needed to overcome the Doppler reactivity feedback for the fuel temperature being reduced to the no-load temperature plus
- the reactivity needed to overcome the reduction of the core coolant density from the plant initial conditions down to the RCS no-load temperatures at nominal pressure conditions.

The approach of using the negative reactivity required to just meet the shutdown margin ensures that the safety analyses support the Technical Specifications. The Westinghouse reload methodology confirms that there is sufficient negative reactivity in the rods when satisfying the Technical Specification Rod Insertion Limits at the associated power level to overcome the Doppler reactivity effect and moderator changes in going from a full power condition to a zero power condition and to take the reactor subcritical by the Technical Specification value. This calculation assumes that the most reactive rod is stuck out of the core and is checked to ensure that there is sufficient negative reactivity to meet the shutdown margin at any time in the cycle.

This process is performed each cycle and helps ensure that the safety analyses remains bounding with respect to the shutdown margin requirement. Rod worth measurements are performed at the beginning of each cycle to ensure that the measured rod worths are within the rod worths, including uncertainties, determined in the core design calculations. This verification ensures that the core design calculations for the shutdown margin meet the Technical Specification requirements and safety analysis assumptions.

Comparison of the Current Licensing Basis Steam System Piping Failure Hot Full Power - Post-Trip Event to the Westinghouse (W) RAI Analysis

	Current License	W RAI Response	Comments
Analysis Assumptions:			
Reactor Power	2754 Mwt	2700 Mwt	2% power uncertainty
Tinlet	554°F	535.5°F	W assumes lower Tavg of 563.0°F
RCS Flowrate	363,000 gpm	341,400 gpm	
MTC (End of Cycle)	-32 pcm/F	More negative than -32 pcm/F	W assumes an MTC consistent with the assumption of N-1 rods in the core.
CEA Worth	-7.3 %Δρ	Worth Required To Meet TS SDM	W assumes sufficient trip reactivity to just meet TS SDM
Inverse Boron Worth	115 ppm/%Δρ	111 ppm/%Δρ	Safety Injection boron worth
Break Size	Full Double-Ended Rupture ($6.358\ ft^2$)	Full Double-Ended Rupture ($6.305\ ft^2$)	Slight difference due to conversion of diameter to area.
SG Pressure	949 psia	817 psia	Difference due to different initial Tavg assumed
SG Mass	156521 lbm	141013 lbm	Difference due in part to the different initial Tavg assumed
Feedwater flow	Full Power Feedwater flow to FWI	Full Power Feedwater Flow to FWI	
SI Flow	Minimum Flow From One Pump	Minimum Flow From One Pump	SI is initiated in both cases on low PZR pressure

Comparison to UFSAR Table 15.1.4.3-8
Sequence of Events for the Post-Trip Steam Line Break Event, Inside Containment, at Hot Full Power, without Loss Of Offsite Power and with HPSI Pump Failure

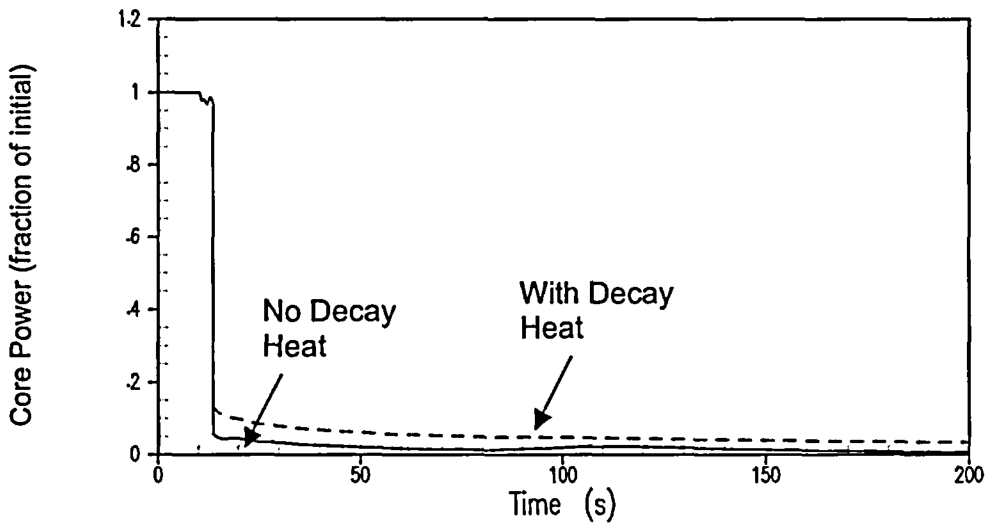
Event	UFSAR Time (Setpoint)	RAI Response Time (Setpoint)
Guillotine break of main steam line inside containment	0 seconds	0 seconds
Low steam generator pressure trip signal	3.50 seconds (540 psia)	2.49 seconds Note 1 (546 psia)
Main Steamline Isolation Signal is Generated	3.80 seconds (520 psia)	2.78 seconds (520 psia)
Reactor Trips	4.65 seconds	3.63 seconds
Main Steam and Feedwater Isolation Valves begin to close	4.95 seconds	7.83 seconds Note 2
CEA's Drop into the core	5.45 seconds	4.63 seconds
Main Feedwater Isolation Valves are Fully Closed (5.15 seconds)	8.95 seconds	7.93 seconds
Main Steamline Valves are Fully Closed (6.75 seconds)	10.55 seconds	9.53 seconds
Steam Generator Differential Pressure setpoint is reached	11.47 seconds (360 psid)	Not assumed
Pressurizer empties	19.62 second	49.00 seconds
Safety Injection Actuation Signal generated on low pressurizer pressure	19.97 seconds (1578 psia)	31.81 seconds (1646 psia) Includes harsh environ. error
Ruptured steam generator empties (<5000 lbm)	48.91 seconds	~185 seconds Note 3
High Pressure Safety Injection Pump reaches full speed	49.97 seconds	51.81 seconds
Power (at/near peak post-trip reactivity)	51.80 seconds (10% of 2700 MWt including decay heat)	~90 seconds Note 3 (~3.4% of 2700 MWt with no decay heat) (~6.8% with maximum decay heat)
Maximum post-trip reactivity	53.85 seconds (-0.6171%$\Delta\rho$)	~110 seconds (~-0.600%$\Delta\rho$)
Safety injection, boron enters the core	104.3 seconds	~100 seconds

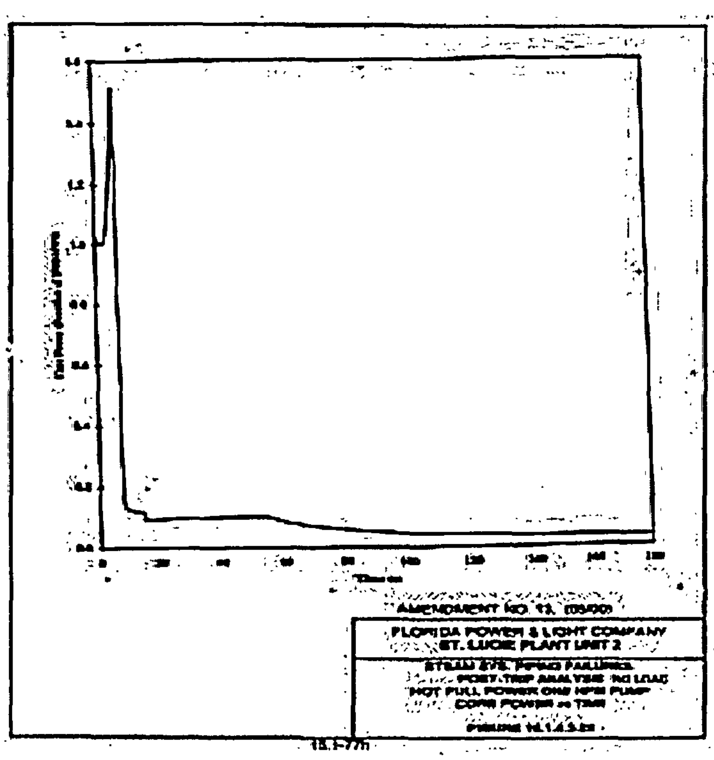
Note 1 The low steamline pressure setpoint is reached sooner in the RAI response because of the lower initial SG pressure.

Note 2 The RAI response assumes that the isolation valves remain fully open until the last 0.1 seconds where it is assumed that the valves rapidly close.

Note 3 The UFSAR analysis model of the steam generator tube bundle heat transfer artificially forces a full heat transfer coefficient till there is 5000 lbm of inventory in the steam generator. The licensing submittal/RAI responses model the heat transfer coefficients based upon the conditions in the tube bundle.

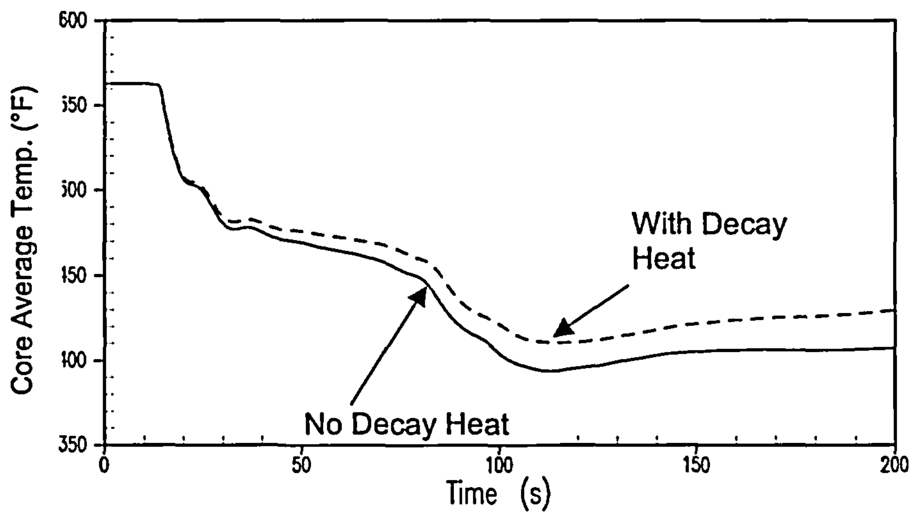
Figure RAI 7-1:
HFP SLB Results Comparison
Core Power Versus Time RAI Analysis
(With and Without Decay Heat) vs. UFSAR AOR
(UFSAR *Figure* 15.1.4.3-23)

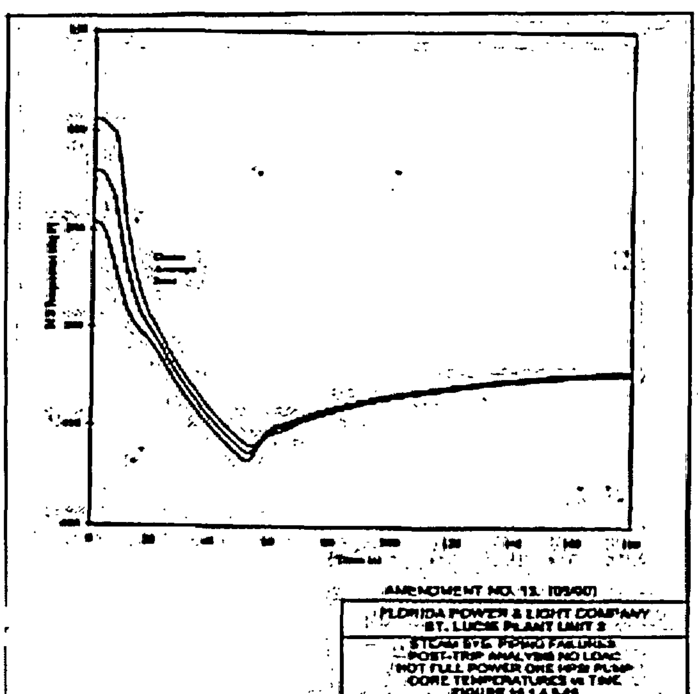




Note that in the RAI Analysis curves, there is no increase in the core power just beyond the time of event initiation, as observed in the UFSAR plot. This is due to the fact that a low steam line pressure trip is generated and the rods begin to fall into the core before the colder water from the SG can reach the core. The power increase is non-conservative, as it adds additional energy to the RCS and helps retard the eventual cooldown of the RCS following the reactor trip.

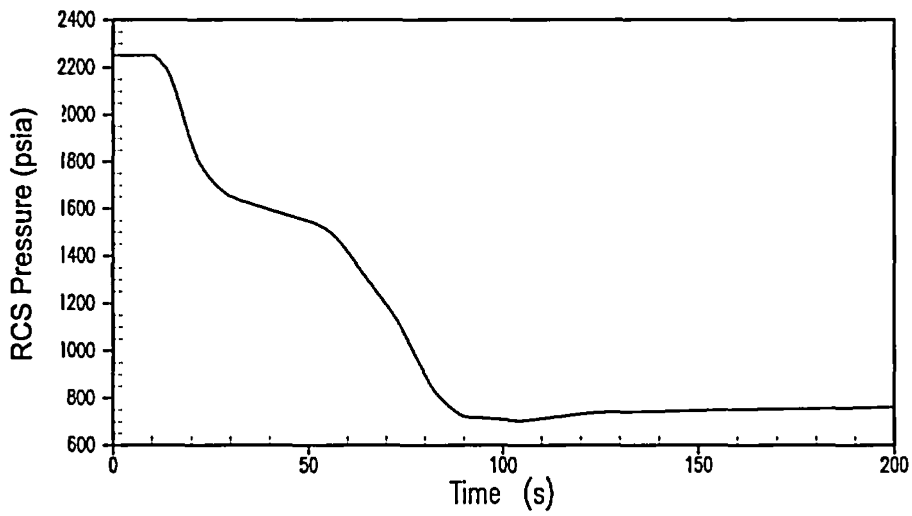
Figure RAI 7-2:
HFP SLB Results Comparison
Core Average Temperature Versus Time
RAI Analysis (With and Without Decay Heat) vs. UFSAR AOR
(UFSAR Figure 15.1.4.3-25)

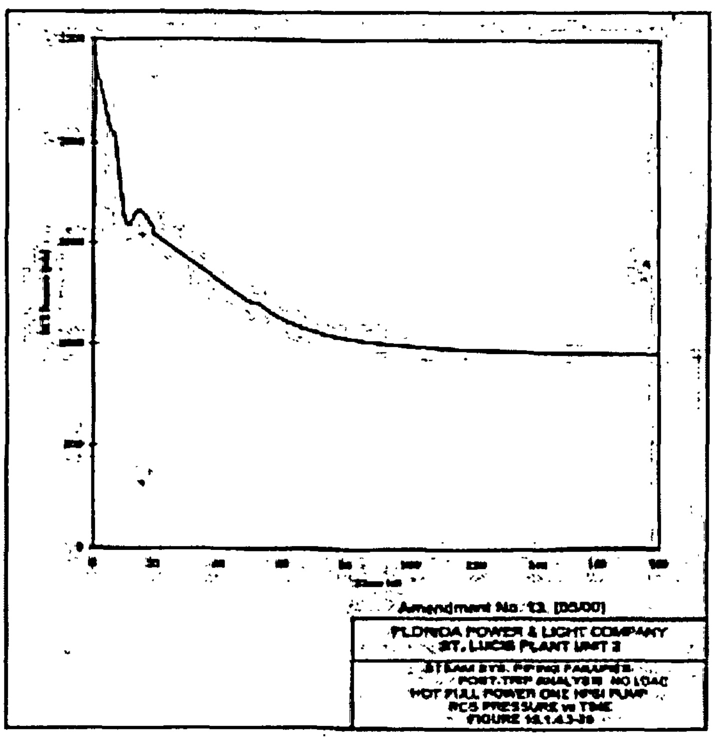




Note that the RAI analysis curves drop slower compared to the UFSAR plot. The reason for this is that the UFSAR analysis assumes full heat transfer in the steam generator until the mass reaches 5000 lbm. A heat transfer coefficient consistent with the mass in the steam generator is assumed in the RAI analysis.

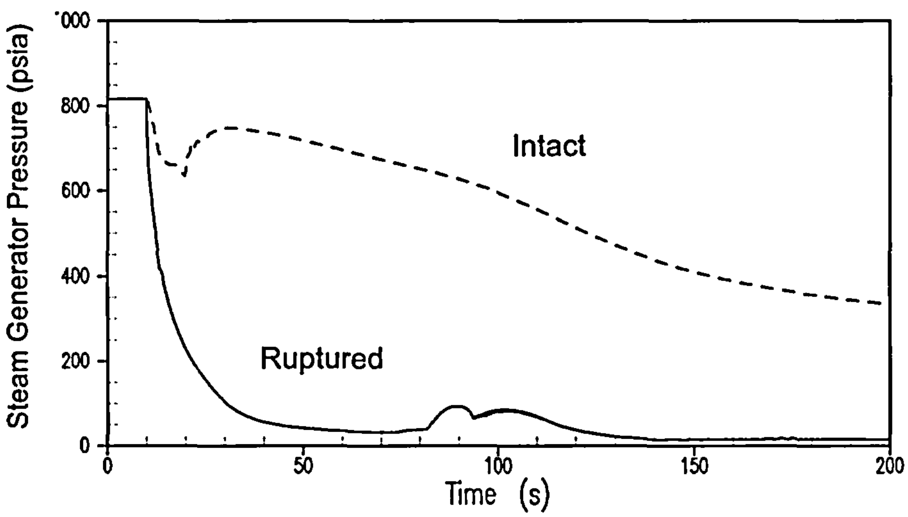
Figure RAI 7-3:
HFP SLB Results Comparison
- RCS Pressure Versus Time -
RAI Analysis vs. UFSAR AOR
(UFSAR Figure 15.1.4.3-26)





Note that the RAI analysis curve drops slower compared to the UFSAR plot. The reason for this is that the UFSAR analysis assumes full heat transfer in the steam generator until the mass reaches 5000 lbm. A heat transfer coefficient consistent with the mass in the steam generator is assumed in the RAI analysis. Also note that the minimum pressure in the RAI analysis is significantly lower than that of the UFSAR analysis.

Figure RAI 7-4:
HFP SLB Results Comparison
- Steam Generator Pressure Versus Time -
RAI Analysis vs. UFSAR AOR
(UFSAR Figure 15.1.4.3-27)



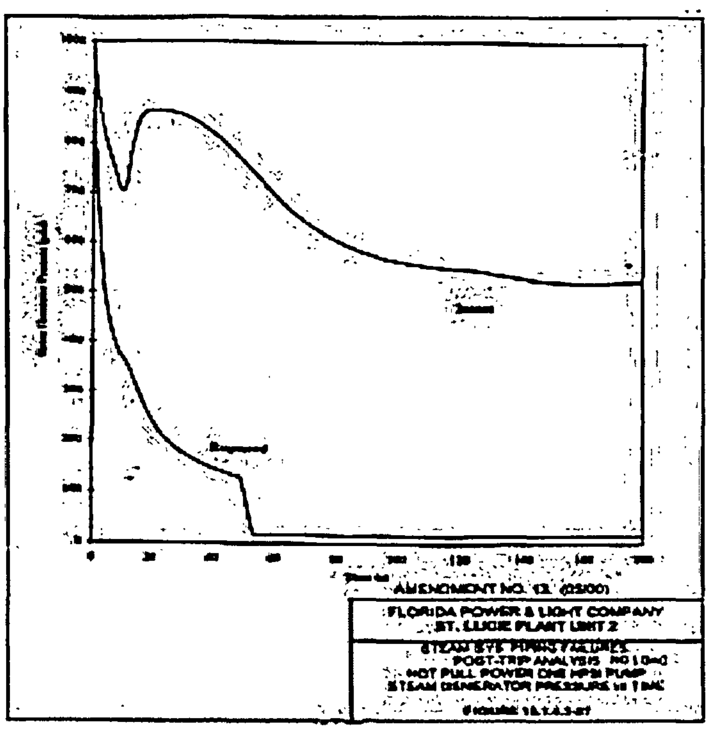
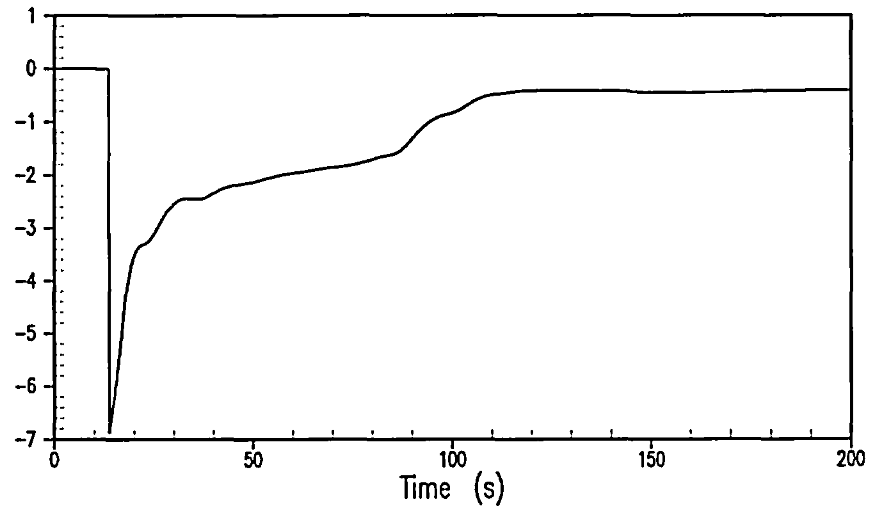
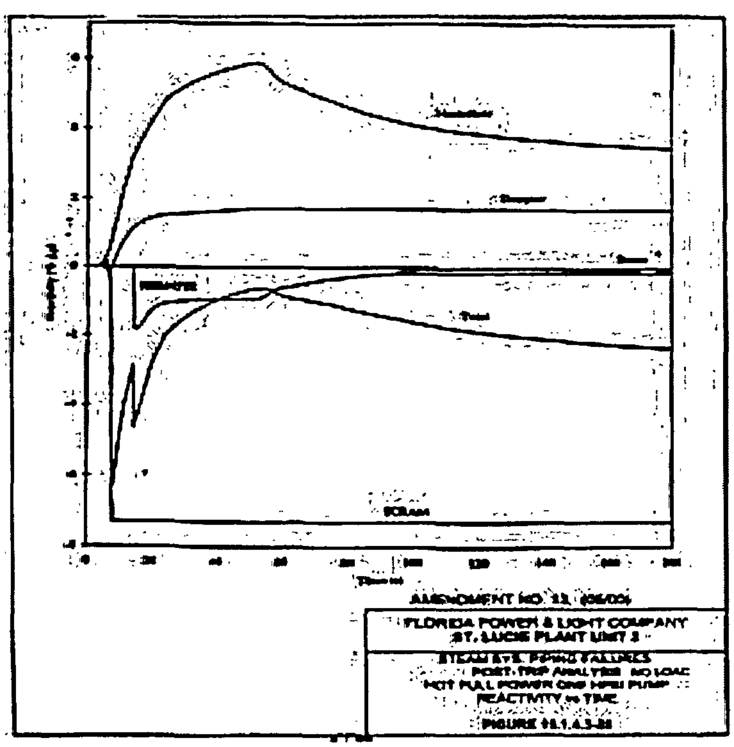


Figure RAI 7-5:
HFP SLB Results Comparison
- Reactivity Versus Time -
RAI Analysis vs. UFSAR AOR
(UFSAR Figure 15.1.4.3-28)





Note that the negative reactivity added in the RAI analysis is comparable and the approach to criticality is approximately the same magnitude as the UFSAR analysis. The approach to criticality is slower due to the reasons stated previously for the RCS temperature (Figure RAI 7-2) and pressure (Figure RAI 7-3).

NRC Request 8: (Summer Sun)

In response to RAI question 1.e, FPL referred its response to the RAI question 1.f response, which further referred to the RAI question 5 response. It is not clear to the NRC staff that the licensee has directly addressed the RAI question 1.e. This RAI question requested that FPL demonstrates that "a LOOP at any time in excess of 3-second will not lead to insufficient borated water from the SI [safety injection] 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 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."

In order to address this question satisfactorily, please provide the following information:

a. An analysis to justify whether the double sequencing phenomenon (as defined in RAI question 1.e) during MSLB events is applicable to St. Lucie Unit 2 or not. The analysis should use assumptions for the LOOP delay time that are consistent with St. Lucie Unit 2 grid stability and electrical design features.

b. Analyses of MSLB events initiated from the HZP and HFP conditions with consideration of the double sequencing effect on the SI system performance, if the double sequencing phenomenon is applicable to St. Lucie Unit 2.

c. An analysis to justify the following statement in the response to RAI question 1.f:

   "As noted previously, the timing of the loss of offsite power is expected to occur in the time frame of 3.0 seconds to 12 seconds from the time of turbine trip."

d. An explanation for the following deviation in the results of the MSLB analysis:

   The response to RAI question 5.a indicated that for the full-power steamline break double-ended rupture case, a return-to-power would not occur. This result is significantly different from the MSLB analysis presented in the UFSAR (page 15.1.44e). The MSLB analysis in the UFSAR showed that for the full power MSLB analyses, the peak return-to-power levels are 10 percent and 7.2 percent for cases with and without ac power available, respectively.

Response 8 Parts a, b, and c:

This response is based on the following assumptions for the loss of offsite power:

- Loss of offsite power could occur between 3 to 12 seconds following reactor/turbine trip, or
- Loss of offsite power could occur 9 seconds following an SIAS.

A safety injection actuation signal (SIAS) can be generated by either a low pressurizer pressure signal or a high containment pressure signal. In either case, a reactor trip/turbine trip will result (either on low pressurizer pressure or high containment pressure) prior to reaching the safety injection signal setpoint.

In order to have a potential for double sequencing, an SI must be initiated before the LOOP occurs. Based upon the most significant grid disturbance possible (initial reactor/turbine operation at full power) a maximum range for a potential loss of offsite power is assumed to be from 3 to 12 seconds following turbine trip. Therefore, for double sequencing to occur, a safety injection signal must occur after turbine trip and before the 12 second maximum delay time for LOOP. This creates, at most, a very limited potential impact on the injected boron in the post-trip analysis of the steamline break. Assuming that an SI signal were generated on a high containment pressure signal within the first few seconds following the break, the SI pumps would be loaded on the buses. The safety injection in the analysis is assumed to begin with a delay of 30 seconds subsequent to the SIAS. If a loss of offsite power were to occur in the time frame of 3 to 12 seconds following reactor trip, the SI pumps would have to be re-sequenced on to the emergency diesel generators (EDG), which would have started on the SI signal. In the worst scenario of loss of offsite power at 12 seconds, the effect of the borated water delivered to the core would be minimally affected. To delay safety injection, the analysis however conservatively does not take credit for the SIAS on high containment pressure and only low pressurizer pressure signal is used to initiate safety injection. Sensitivity calculations were performed to determine the impact on the most severe post-trip SLB analysis.

The scenario, where LOOP occurs at 9 seconds following SIAS, is bounded by the case of LOOP at 12 seconds after reactor/turbine trip stated above.

HZP steamline break sensitivities were run assuming that a loss of offsite power occurred at 0 seconds, 3 seconds and 12 seconds following break initiation and reactor trip, which were assumed to simultaneously occur at the initiation of the event (t=0 seconds). The results are presented in the table shown below. The 0-second sensitivity represents a LOOP case as discussed in Appendix A of the licensing report. The 3-second and 12-second delay cases provide a net impact of the delay of the LOOP from the Appendix A information. For the post-trip steamline break event with LOOP the limiting point in the transient occurs well beyond the point of break initiation. 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. As shown in the table, a variation in the time of SI initiation on the order of 4 seconds has approximately a 1 to 2 ppm effect on the boron in the core at the time of peak heat flux. Therefore, the delay in the timing of loss of offsite power, as mentioned above, is not expected to adversely affect the results, as the boron concentration changes minimally. As described in Appendix A of the licensing report, the LOOP case is non-limiting compared to the post-trip steamline break case with offsite power available.

For the cases shown below, the difference in the borated water at the time of peak heat flux is on the order of a few ppm, which will not change the conclusion that the post-trip analysis of the hot-zero power steamline break with a LOOP is a non-limiting case compared to the case with offsite power available.

Table RAI 8-1
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 12.0 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)	~300 sec	~400	~400 sec	~400 sec
Boron at Time of Peak Heat Flux	~8 ppm	~17 ppm	~16 ppm	~16 ppm

Figure RAI 8-1
Core Heat Flux
For The Post-Trip Steamline Break Event Case
With LOOP at 0 seconds

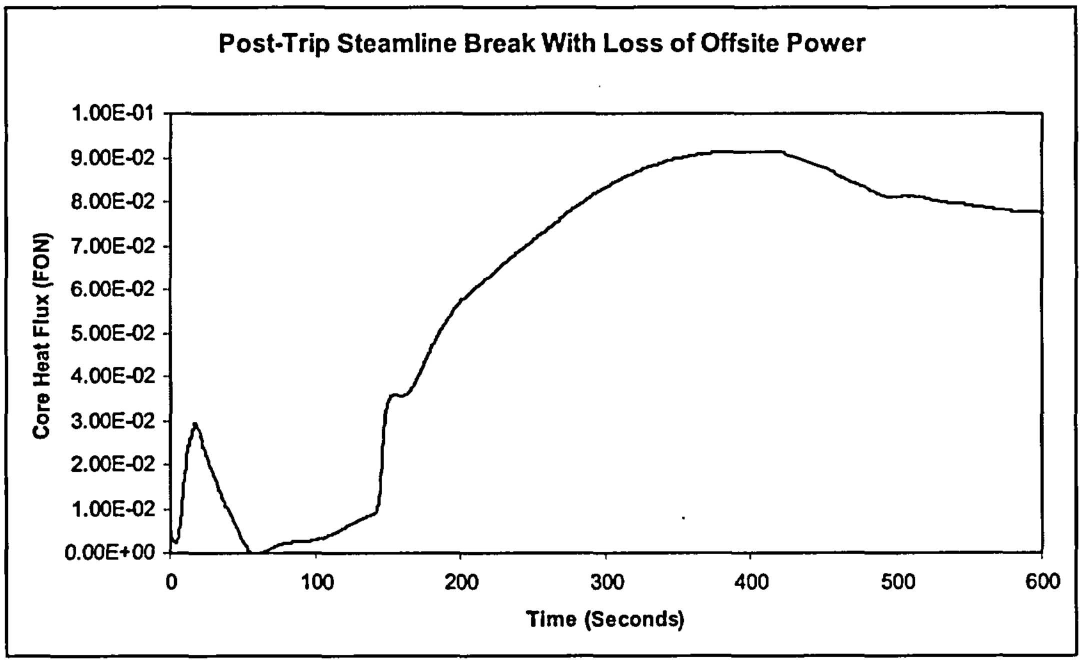
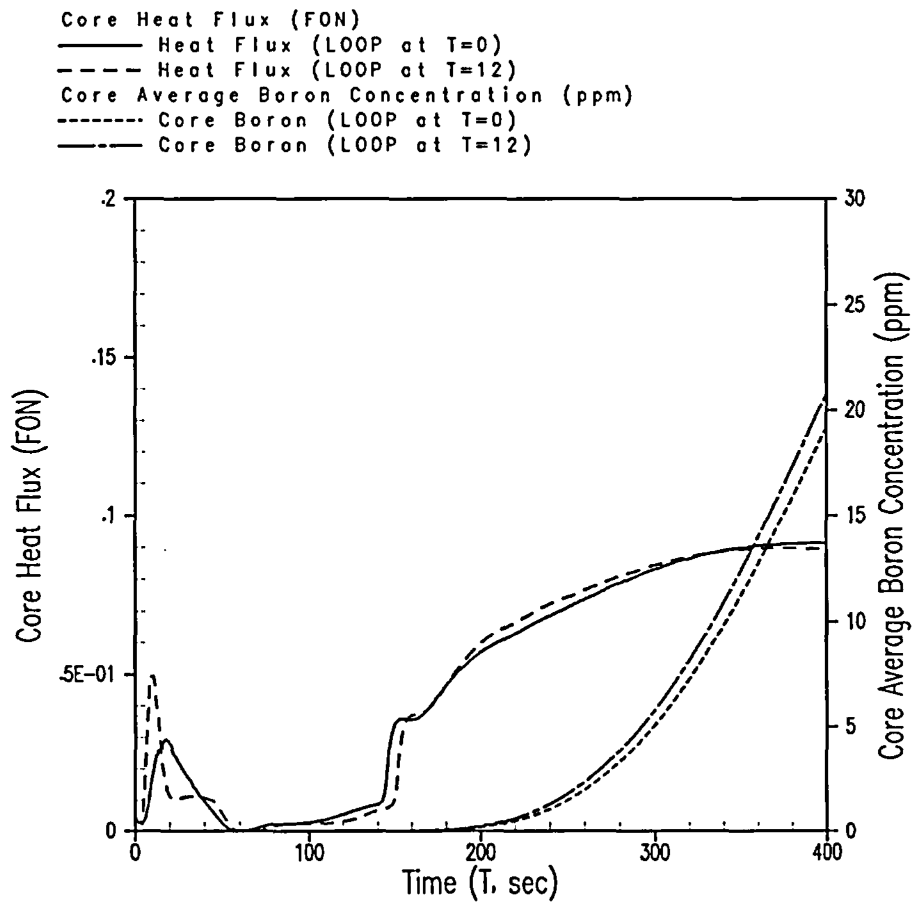


Figure RAI 8-2
Core Heat Flux and RCS Boron Concentration
For The Post-Trip Steamline Break Event Cases
With LOOP at 0 Seconds vs. LOOP at 12 Seconds



Response 8 Part d:

As shown in the response to RAI #7, the UFSAR analysis results and the results from the response to the RAI are very comparable. However, the terminology that should have been used in response to previous RAI Question 5.a noted above should have been that there was not a return to criticality. This is actually the same conclusion that is reached for the current UFSAR analysis. The case as analyzed in response to RAI #7 is less limiting than the hot-zero power case presented in the St. Lucie Unit 2 licensing report for 30% steam generator tube plugging. If one considers the presence of decay heat, the case analyzed in response to RAI #7 is very comparable to the UFSAR case, that is, return to power of 6.8% versus 10%. Therefore, the results are not significantly different and Westinghouse reaches the same conclusion that was reached for the UFSAR case, that is, there is no fuel failure expected.

NRC Request 9: (Paul Clifford)

> The staff is unaware of 2-pump coastdown core flow test data defining inlet flow distribution and cross-flow characteristics. Further, local thermal-hydraulic conditions will be affected by a 2-pump coastdown following 4-pump operation (Pre-Trip MSLB with FFBT) or following 3-pump operation (Locked Rotor with FFBT).
>
> a. Please justify the core-wide and local thermal-hydraulic conditions assumed in the DNBR and local power calculations.
>
> b. If the impact of a 2-pump coastdown on local thermal-hydraulic conditions is not specifically modeled, please discuss conservatisms in the methodology which ensure an overall conservative DNBR calculation and fuel failure estimation.

Response 9:

Westinghouse is also not aware of any 2 out of 4 pump coastdown test data that are applicable to a pre-trip steamline break (SLB) or a locked rotor event with failure of fast bus transfer (FFBT). However, the impact of a 2-pump coastdown on core inlet flow distribution is offset by the following conservative assumptions in the current methodology for the St. Lucie Unit 2 DNBR calculation:

Transient nuclear power does not credit any decrease in the rod drop time due to the flow reduction from the 2-pump coastdown for this case.

For transient nuclear power calculation, the trip reactivity represents the minimum available integrated rod worth following a plant trip signal, based on the most bottom-peaked axial power shape.

The hot assembly with the peak rod at the FR design limit and a low peak-to-average power ratio coincides with the non-peripheral core location having the largest flow reduction.

In estimating rods in DNB, the peak rod power limit from the hot channel is applied to all fuel rods of the core through the rod census curve.

Locked Rotor With FFBT:

A bounding flow reduction from the CE-PWR 1 out of 4 pump coastdown test data is applied to the hot assembly from the beginning of the transient, in addition to the flow coastdown imposed by the FFBT. This value is applicable to St. Lucie Unit 2 and is the same as that assumed in the current licensing basis.

DNBR calculations are based on the most DNB-limiting top-peaked axial distribution for the cycle operation and the peak rod at the design FR (FΔH) limit in the hot assembly. For this case, no reactivity feedback effects were credited from the 2-pump coastdown.

Pre-Trip MSLB With FFBT:

Since it is a cooldown event, a bounding flow reduction from the CE-PWR 4-pump operation test data is applied to the hot assembly from the beginning of the transient, in addition to the flow coastdown imposed by the FFBT. This value is applicable to St. Lucie Unit 2 and is the same as that assumed in the current licensing basis.

DNBR calculations are based on a top-skewed accident-specific axial power shape and an FR tilt factor of 1.02 applied to the design limit of the peak rod in the hot assembly. For this case, no reactivity feedback effects were credited from the 2-pump coastdown. The tilt factor accounts for loop asymmetric effect during the transient.

The above assumptions ensure an overall conservative DNBR calculation and fuel failure estimation, with the 2-pump coastdown in a postulated pre-trip MSLB with FFBT event or a locked rotor with FFBT event.

NRC Request 10: (Paul Clifford)

Provide the details of the limiting Locked Rotor with Single Failure event. If fuel failure is predicted, provide the following:

a. Description of the DNB propagation methodology for current and future reloads.
b. Demonstrate no DNB propagation occurs.
c. Description of the methodology for calculating the number of failed fuel rods for current and future reloads.
d. Demonstrate that the number of failed fuel rods is within the assumptions in the dose calculation previously submitted.

Response 10:

The locked rotor event was reanalyzed with an assumed fast bus transfer failure. The description of the accident and the method of analysis are as described in Section 5.1.15 of the original licensing report, except for the limiting single failure being failure of fast bus transfer. The calculated peak RCS pressure is 2646 psia, which meets the acceptance criterion of 2750 psia. The calculated peak cladding temperature is 1639.4°F, which meets the acceptance criterion of 2700°F. The zirconium-steam reaction at the hot spot is 0.2 percent by weight, which meets the acceptance criterion of 16 percent by weight. The total percentage of fuel rods calculated to experience DNB is 1 percent, which is less than the value assumed in the radiological dose evaluation (13.7 percent) submitted in L-2003-220. The time sequence of events for each case is presented in Table RAI 10-1.

Based on a comparison of results, it is slightly more limiting to assume a fast bus transfer failure in the locked rotor analysis. However, all results continue to satisfy the applicable acceptance criteria. Figures 1 through 9 present transient response of the locked rotor analysis with the failure of fast bus transfer.

Table RAI 10-1:
Sequence of Events – Reactor Coolant Pump Locked Rotor With FFBT

Event	Time (seconds)	
	Rods-in-DNB Case	PCT Case
Rotor on One Pump Locks	0.0	0.000
Low Flow Reactor Trip Setpoint Reached	0.227	0.233
Reactor Trip (Breakers Open)	0.627	0.633
Failure of Fast Bus Transfer (Two RCPs Coastdown)	0.627	0.633
Rod Motion Begins (0.74-Second Following Breaker Opening)	1.367	1.373
Minimum DNBR	2.90	N/A
Maximum Cladding Temperature Occurs	N/A	3.30
Maximum RCS Pressure Occurs	N/A	3.600
Remaining Active RCP Begins Coastdown	3.627	3.633

For St. Lucie Unit 2, when DNB is determined to occur in the analysis of any Condition III or IV event, the potential effects of DNB propagation are evaluated using the same process used in the current licensing basis. This evaluation has concluded that DNB propagation will not lead to more rod failures than those calculated due to DNB for those events.

For St. Lucie Unit 2, when the DNB SAFDL is violated in the thermal-hydraulic analysis for any event, the number of rods in DNB is calculated in accordance with the general approach identified in WCAP-9272. This is consistent with standard Westinghouse process for plants using the Westinghouse reload methodology. Following is an overview of this process:

1. Transient Analysis provides statepoints that cover the most DNB limiting conditions of the transient to Thermal-Hydraulics.

2. Thermal-Hydraulic Design uses the VIPRE code and the applicable DNB correlation to determine the limiting statepoint.

3. If the minimum DNBR at the limiting statepoint is below the DNB SAFDL, Thermal-Hydraulic Design performs additional DNBR calculation using the VIPRE code to determine the $F_{\Delta H}$ value that will satisfy the DNB SAFDL.

4. Physics generates the cycle-specific, burnup-dependent pin census files that are scaled to the Technical Specification FΔH limit at the all rods out (ARO) condition.

5. From this census, the number of rods in DNB (i.e., the number of rod failures for the dose analysis) is identified deterministically as those rods with an FΔH value above the FΔH value that satisfies the DNB SAFDL.

6. For each cycle, this number of rods in DNB is confirmed to be less than the number of rod failures determined in Step 5 as part of the reload safety evaluation.

This process, employed to the analyses supporting the 30% steam generator tube plugging submittal and associated RAIs, has confirmed that the predicted rod failures remain less than the rod failure limit assumed in the doses analyses for the cases for which DNB is predicted:

- Inside containment steamline break (with LOOP at accident initiation and a low flow trip setpoint based on harsh containment environment), and

- Seized rotor (with failure of fast bus transfer)

Figure RAI 10-1:
Locked Rotor PCT/Peak RCS Pressure Case Results with FFBT
Total Core Inlet Flow

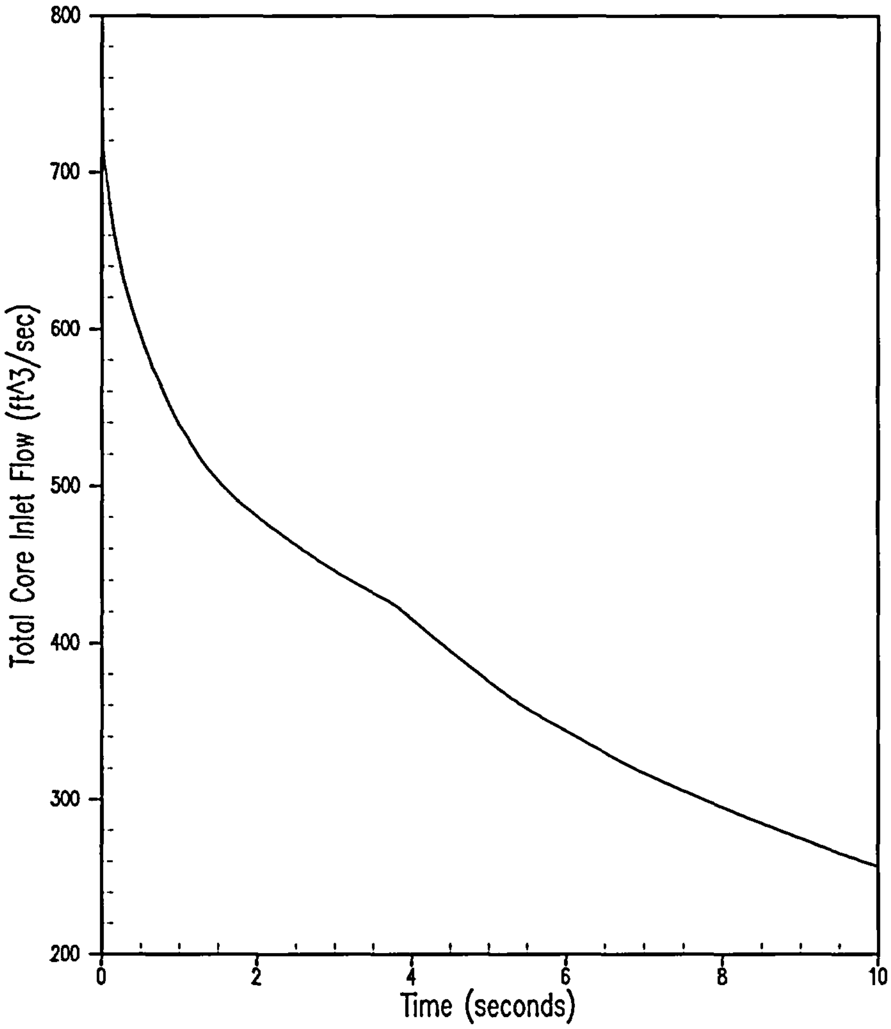


**Figure RAI 10-2:
Locked Rotor PCT/Peak RCS Pressure Case Results
With FFBT RCS Loop Flow**

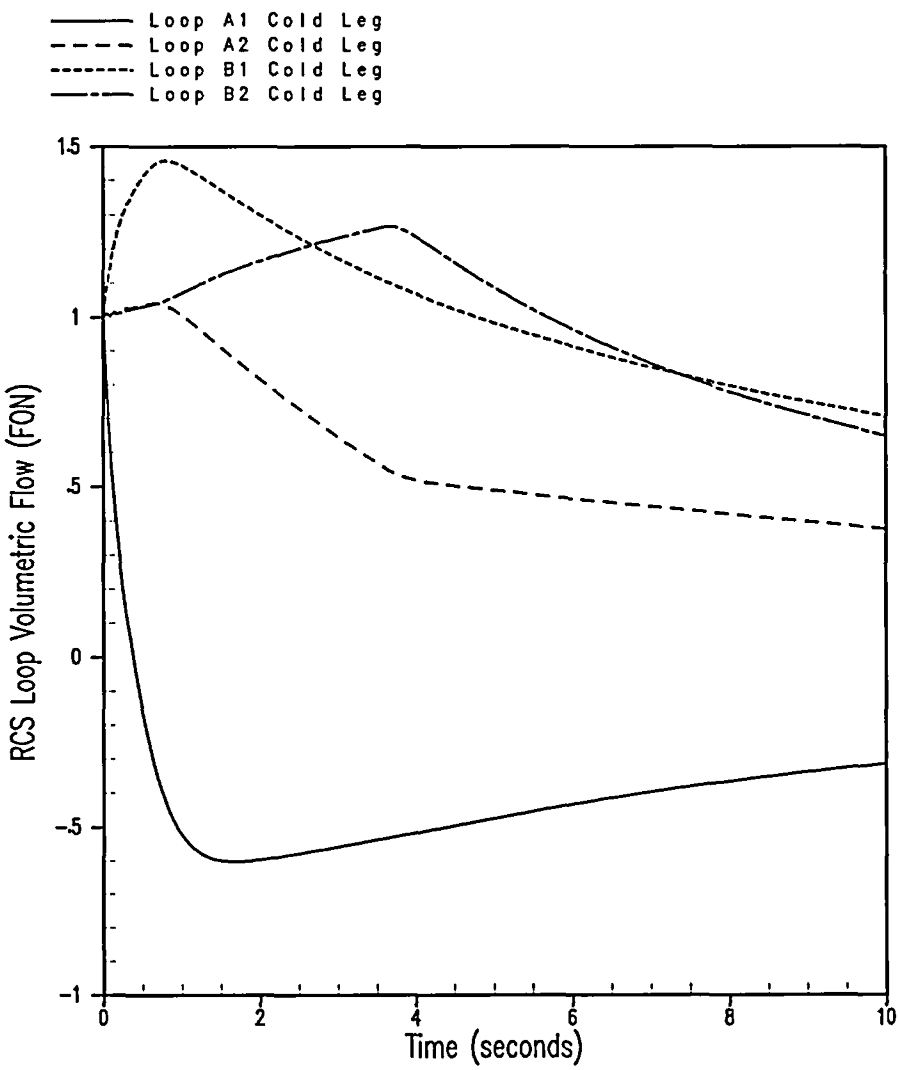


Figure RAI 10-3:
Locked Rotor PCT/Peak RCS Pressure Case Results
With FFBT Nuclear Power

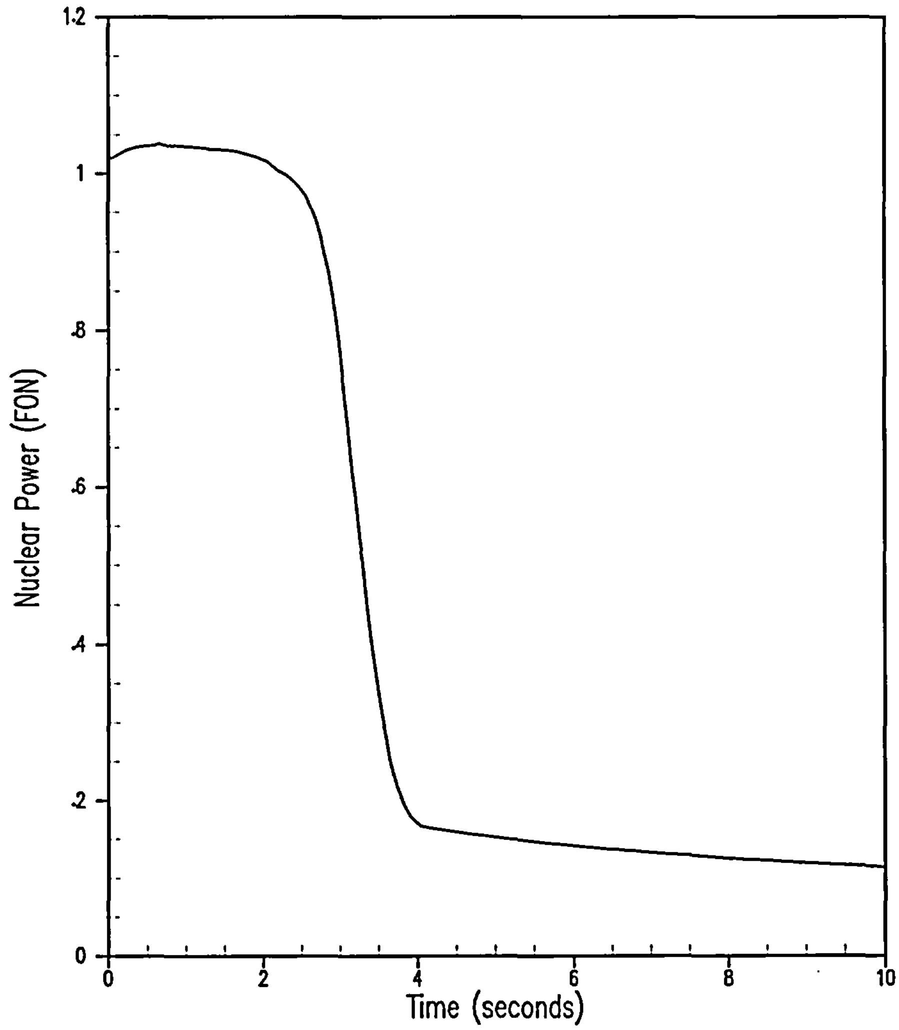


Figure RAI10-4:
Locked Rotor PCT/Peak RCS Pressure Case Results With FFBT
Core Average Heat Flux

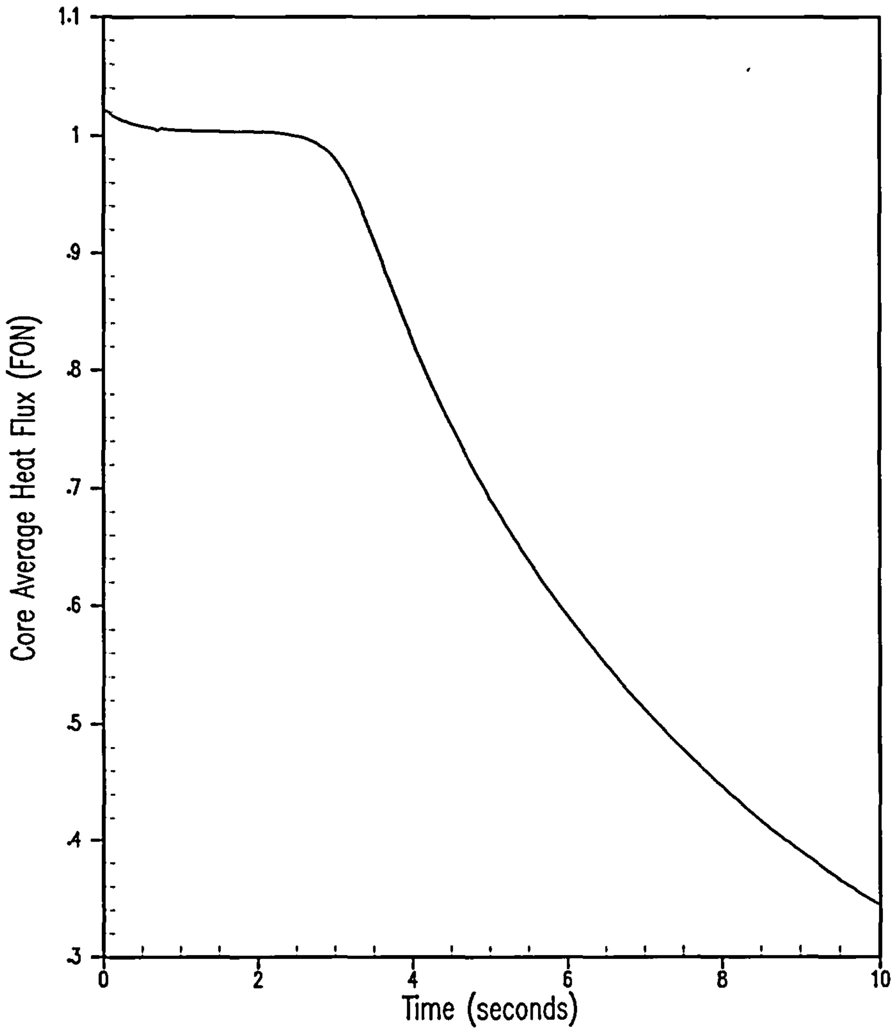


**Figure RAI 10-5:
Locked Rotor PCT/Peak RCS Pressure Case Results With FFBT
Pressurizer Pressure**

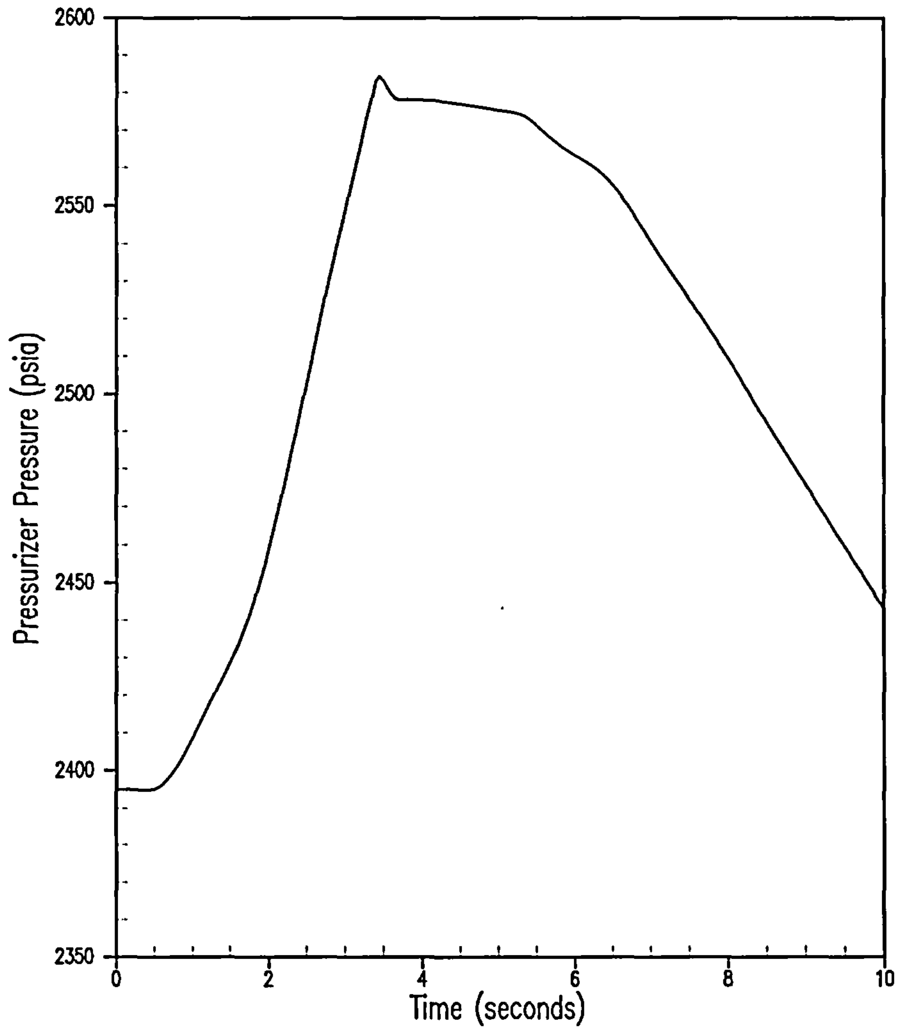


**Figure RAI 10-6:
Locked Rotor PCT/Peak RCS Pressure Case Results With FFBT
Vessel Lower Plenum Pressure**

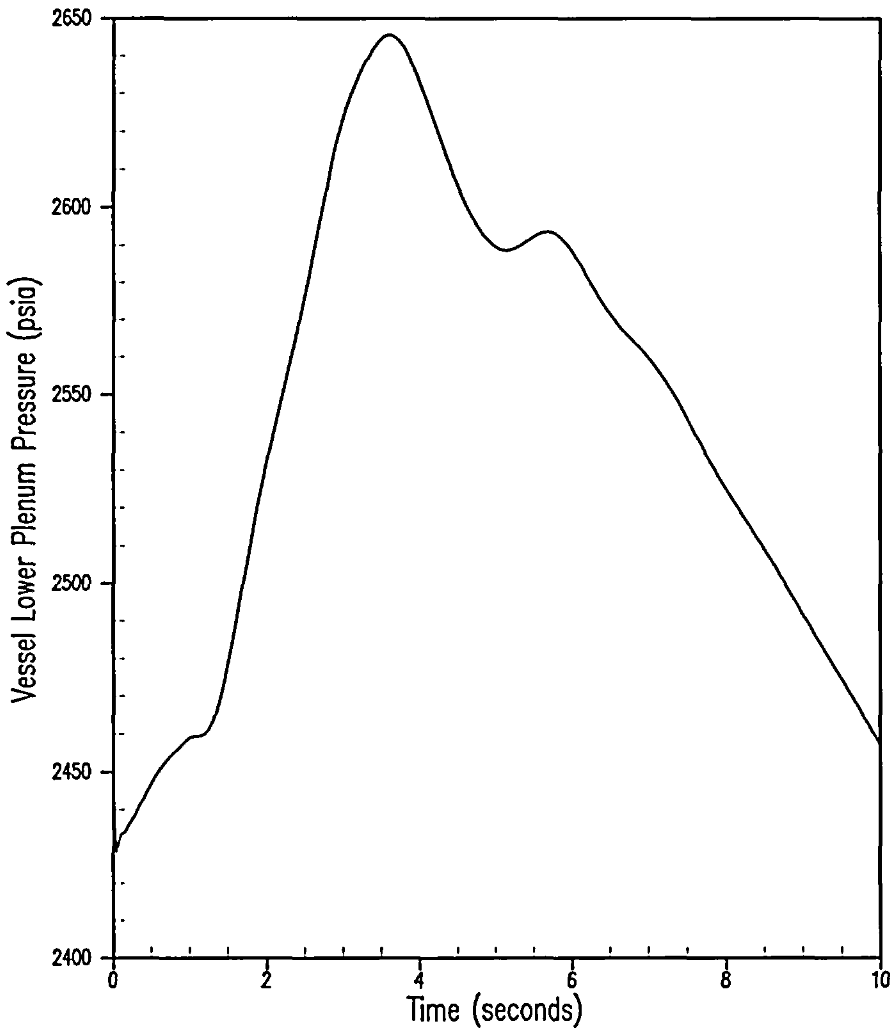


Figure RAI 10-7:
Locked Rotor PCT/Peak RCS Pressure Case Results With FFBT
RCS Loop Temperature

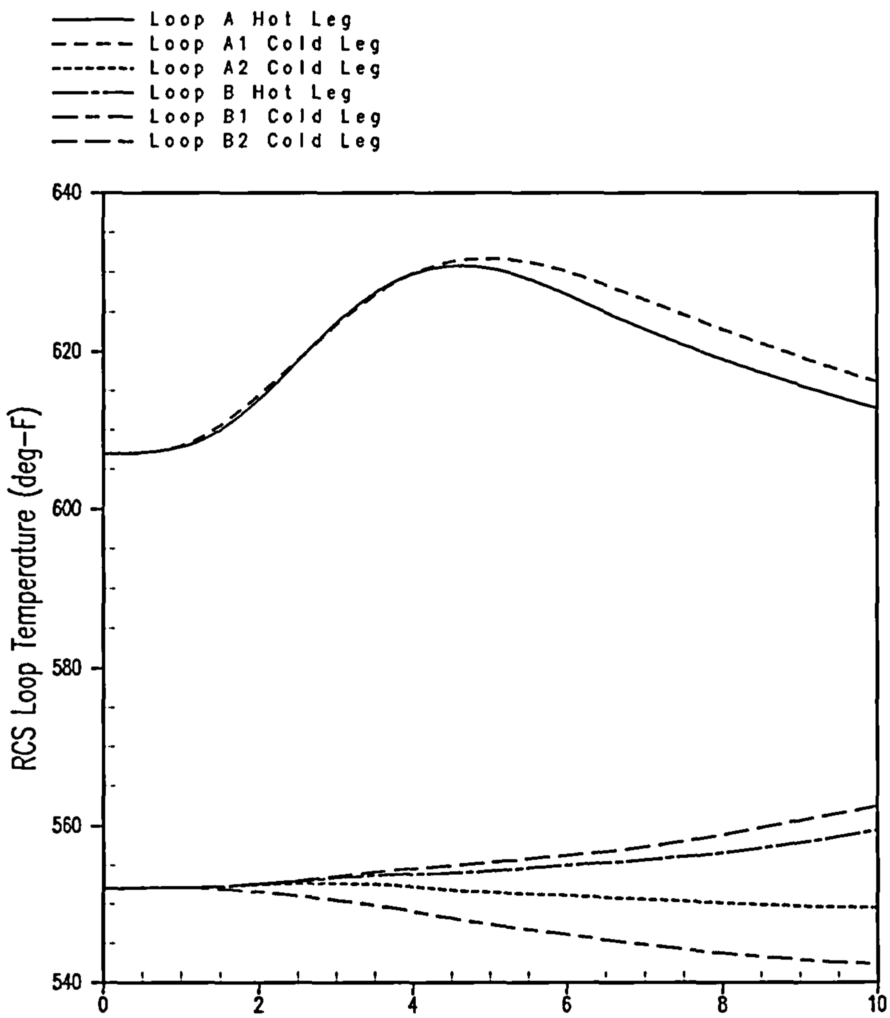


Figure RAI 10-8:
Locked Rotor PCT/Peak RCS Pressure Case Results With FFBT
Hot Channel Heat Flux

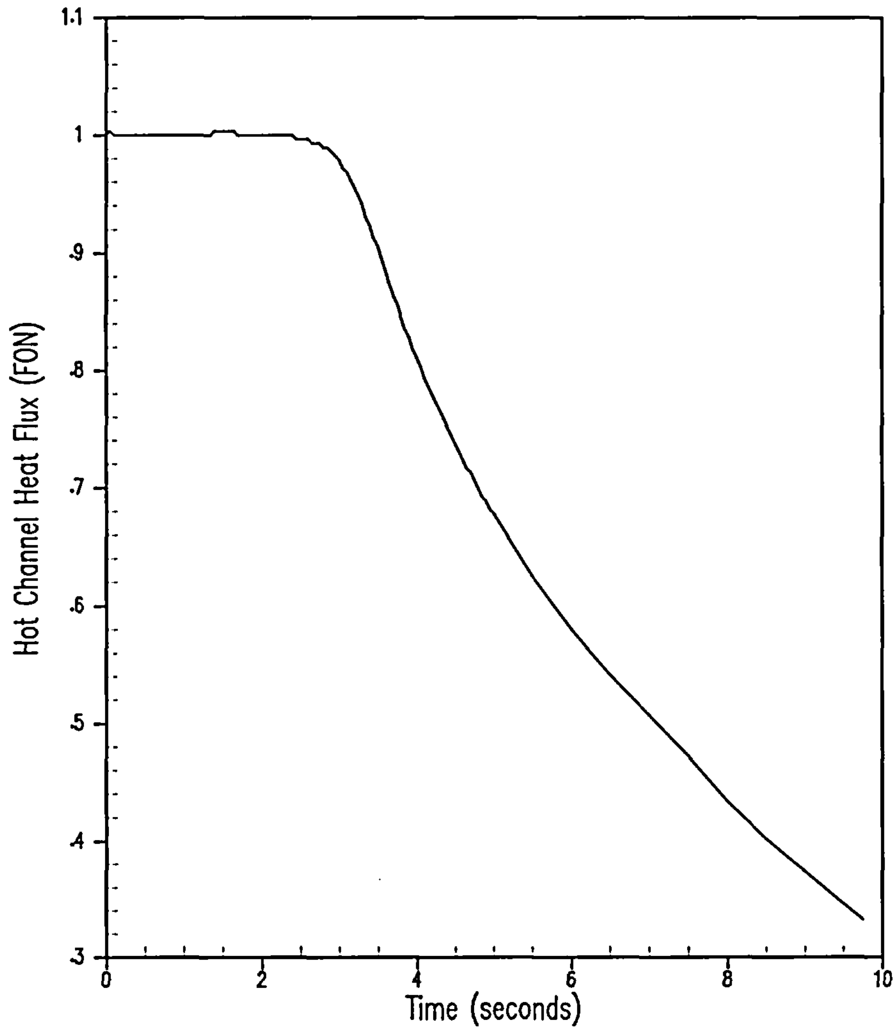
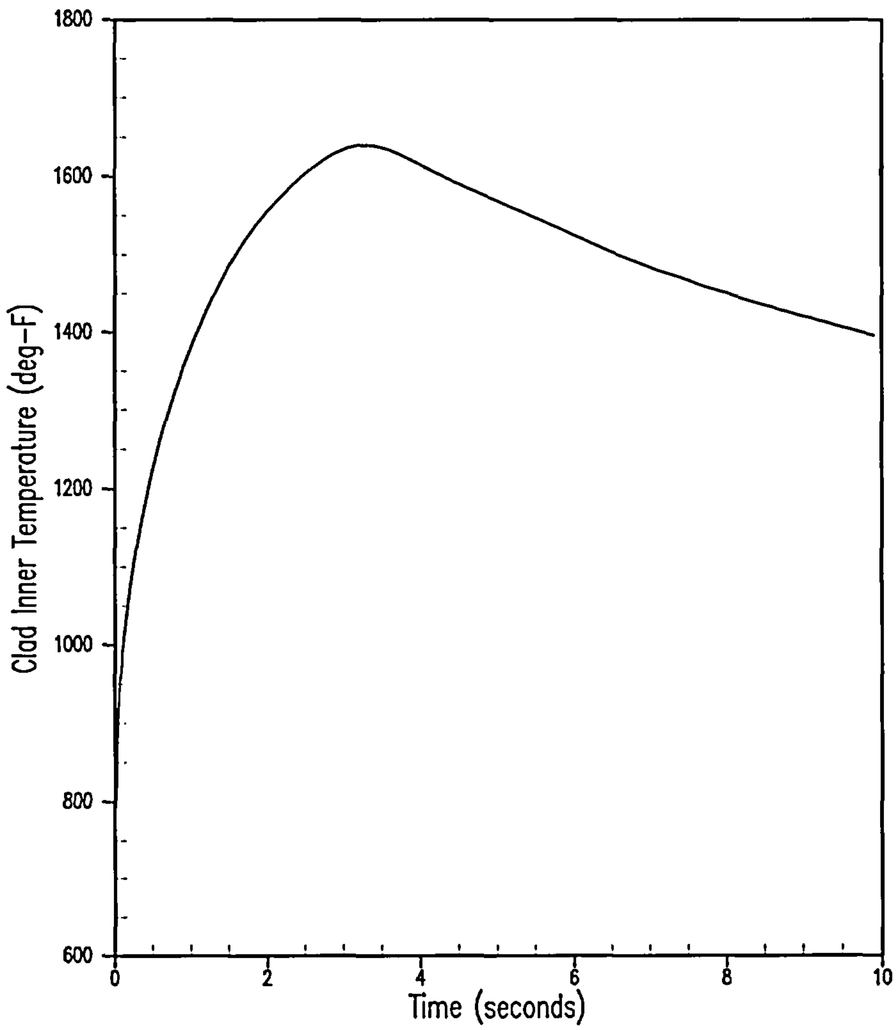


**Figure RAI 10-9:
Locked Rotor PCT/Peak RCS Pressure Case Results With FFBT
Hot-Spot Cladding Inner Temperature**



Attachment 2

Alternative Analysis

Analyses Supporting 0-Second Delay for LOOP Following Turbine Trip

In response to discussions with the NRC on December 17, 2004, FPL has proposed an alternative parallel approach for review of the St. Lucie Unit 2 30% Steam Generator Tube Plugging (SGTP) proposed amendment submittal (L-2003-276). The alternative approach is based on a return to the current licensing basis assumptions relative to loss of offsite power (LOOP) timing for pre-trip main steamline break and main feedline break. These assumptions assume loop coincident with the reactor trip breaker opening. The appropriate revised licensing report sections for the original licensing submittal of L-2003-276 are provided in this attachment. This attachment only applies to the alternative approach for the review and provides responses to RAI Questions 4 and 7 as they apply to this alternative approach.

Analyses Supporting 0-sec Delay for LOOP Following Turbine Trip

In response to discussions with the NRC, FPL has proposed a parallel approach for review of the St. Lucie Unit 2 30% Steam Generator Tube Plugging submittal (L-2003-276) based on a return to the current licensing basis assumptions relative to Loss of Offsite Power (LOOP) timing. These assumptions are summarized below:

Event	LOOP assumption	Comments
Seized Rotor	3 seconds after reactor trip breaker opening (RTBO)	This is the case presented in the original submittal
Steamline Break (Pre-trip)	Coincident with reactor trip breaker opening (RTBO with 0 seconds delay)	A composite case representing four pump coastdown superimposed on the limiting pre-trip steamline break condition at the time of RTBO
Feedline Break	Coincident with RTBO (RTBO with 0 seconds delay)	Original licensing report Section 5.1.12 revised to include with-LOOP analysis results. The with-LOOP peak RCS pressure results were shown to meet the 120% of design pressure limit (3000 psia). For the original analysis results (without LOOP), all cases were shown to meet the 110% of design pressure limit (2750 psia).

The corresponding revised licensing report sections for the original licensing submittal of L-2003-276 are provided on the following pages.

5.1.5 Pre-Trip Steam System Piping Failure With Loss of Offsite Power at Time of Reactor Trip Breaker Opening

Accident Description

A rupture in the main steam system piping from an at-power condition creates an increased steam load, which extracts an increased amount of heat from the RCS via the steam generators. This results in a reduction in RCS temperature and pressure. In the presence of a strong negative moderator temperature coefficient, typical of end-of-cycle life conditions, the colder core inlet coolant temperature causes the core power to increase from its initial level due to the positive reactivity insertion. The power approaches a level equal to the total steam flow. Depending on the break size, a reactor trip may occur due to overpower conditions or as a result of low steam generator pressure.

The purpose of this section is to describe the analysis of a steam system piping failure occurring from an at-power initial condition and to demonstrate that core protection is maintained prior to and immediately following reactor trip. The analysis assumes a loss of offsite power (LOOP) occurs coincident with the reactor trip breaker opening. The loss of offsite power results in the coastdown of all four reactor coolant pumps. This event is analyzed to demonstrate that the acceptance criteria related to the amount of fuel failures and subsequent radiological consequences are satisfied for this event.

Method of Analysis

The analysis of the steamline rupture is performed in the following stages:

- The RETRAN code (References 1 and 2) is used to calculate the nuclear power, core heat flux, and RCS temperature and pressure transients resulting from the cooldown following the steamline break.
- The RETRAN code is also used to calculate the primary flow coastdown following reactor trip as a result of the loss of offsite power, which results in all four of the reactor coolant pumps coasting down.
- The core radial and axial peaking factors are determined using the thermal-hydraulic conditions from the transient analysis as input to the nuclear core models. The VIPRE code (see Section 4.2 of the St. Lucie Unit 2 30% SGTP Licensing Submittal) is then used to calculate the DNBR for the limiting time during the transient.

This accident is analyzed with the Revised Thermal Design Procedure. Plant characteristics and initial conditions are provided in Table 5.1.0-2. Any fuel rods having DNBR below the Safety Analysis Limit (SAL) DNBR values defined in Section 4.2 are assumed to be in DNB.

The following assumptions are made in the transient analysis:

Initial Conditions – The initial core power, reactor coolant temperature, and RCS pressure are assumed to be at their nominal full-power values. The full-power condition is more limiting than part-power in terms of DNBR. The RCS minimum measured flow is used. Uncertainties in initial conditions are included in the DNBR limit as described in Reference 3.

Break Size – The limiting break size of 3.2 ft^2 is analyzed and trips on the variable high power delta-T reactor trip function. The analysis performed superimposes the four pump coastdown on the limiting statepoints to obtain a conservative composite case. A detailed break spectrum and MDC sensitivity calculations crediting the effect of the flow coastdown following a LOOP on the neutron power would result in less limiting results as compared to the composite case presented here. These sensitivity calculations may be performed in the future to remove this excess conservatism and gain margin.

Break Flow – In computing the steam flow during a steamline break, the Moody curve (Reference 4) for fL/D = 0 is used.

Reactivity Coefficients – The limiting break size is analyzed with a 0.30 Δk/gm/cc moderator density coefficient (MDC) and otherwise assumes end-of-cycle reactivity feedback coefficients with the minimum Doppler power feedback to maximize the power increase following the break.

Protection System – This analysis only considers the initial phase of the transient initiated from an at-power condition. Protection in this phase of the transient is provided by a reactor trip on variable high power delta-T.

Loss of Offsite Power - This analysis assumes a loss of offsite power occurs coincident with the reactor trip breaker opening, causing all four of the reactor coolant pumps to coastdown. This four-pump coastdown is used along with the pre-trip steamline break statepoints for power, pressure and temperature to determine the resulting DNBR, as calculated by the VIPRE code.

Control Systems – The results of the analysis would not be more severe as a result of control system actuation. Therefore, their effects have been ignored in the analysis. Control systems are not credited in mitigating the effects of the transient.

Axial Power Distributions – A DNB-limiting axial power shape (top peaked) without crediting the flow coastdown is used in the DNBR calculation. In the RETRAN analysis, a conservative (bottom peaked) trip reactivity worth versus rod position is modeled in addition to a conservative CEA drop time of 2.341 seconds from release to full insertion.

Results

The time sequence of events for the limiting case discussed above is shown in Table 5.1.5-1. Less than 2.5% of fuel rods were in DNB at the most limiting time step of the transient.

Conclusions

A detailed analysis to assess both minimum DNBR and peak linear heat rate was performed using radial and axial core peaking factors from the existing limiting case, with all pumps coasting down imposed at the reactor trip. Because the radial and axial peaking factors are dependent on the cycle-specific loading pattern, the minimum DNBR and peak linear heat rate are verified to meet their respective limits on a cycle-specific basis through the WCAP-9272 reload process. The initial analysis supporting the implementation of the WCAP-9272 reload process for St. Lucie Unit 2 concludes that both the dose limit for the SLB event and the peak linear heat rate limit are met for the limiting case. Although the steamline break accident is classified as an ANS Condition III or IV event, the analysis demonstrates that the acceptance criteria are satisfied for all ruptures occurring from an at-power condition.

In addition, the conclusions in the original licensing report Section 5.1.5 that the DNB design basis is satisfied apply to cases where offsite power is maintained and therefore continues to satisfy Condition II criteria and bound the Condition II events of Sections 5.1.2 (Inadvertent Opening of Steam Generator Safety Valve/Atmospheric Steam Dump) and 5.1.4 (Increase in Main Steam Flow).

References

1. WCAP-14882-P-A, Rev. 0, *RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses*, April 1999.

2. EPRI NP-1850-CCM, Rev. 6, *RETRAN-02-A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems*, December 1995.

3. WCAP-11397-P-A, *Revised Thermal Design Procedure*, April 1989.

4. Moody, F. S., *Transactions of the ASME Journal of Heat Transfer*, Figure 3, page 134, February 1965.

Table 5.1.5-1 Steamline Break Analysis - Sequence of Events		
Event	**Time (sec)**	**Value**
MSLB Transient Initiated	0.01	
Variable Overpower – ΔT Power Setpoint Reached	10.13	112.2 %
Reactor Trip Signal Generated	10.53	0.40 sec. delay from setpoint
Loss of Offsite Power – All Four RCPs Coast Down	10.53	LOOP assumed coincident with reactor trip
Turbine Trip on Reactor Trip	10.78	0.25 sec. delay from reactor trip
CEA Release	11.27	0.74 sec. delay from reactor trip
Minimum DNBR Reached	12.60	1.39 (SAL DNBR)[2]
Peak Linear Heat Rate Reached	12.60	21.23 kW/ft
Peak Heat Flux Reached	12.60	131.0 %

When you superimpose a complete loss of flow at the time of reactor trip break opening upon the previous transient, the transient plots are identical to those presented in Section 5.1.5 of the original submittal.

2 The SAL DNBR of 1.39 meets the 95/95 DNB design criterion with additional margin as discussed in Section 4.3 of the original submittal.

5.1.12 Feedwater Line Break

Accident Description

A major feedwater line rupture is defined as a break in a feedwater line large enough to prevent the addition of sufficient feedwater to maintain shell-side fluid inventory in the steam generators. Depending upon the size and location of the rupture and the plant operating conditions, the event can cause either a cooldown or a heatup of the reactor coolant system. Since the RCS cooldown resulting from a secondary system pipe break is covered by the steamline break event, only the RCS heatup aspects are emphasized for the case of feedwater line break.

A feedwater line break reduces the capability of the secondary system to remove heat generated by the core from the RCS. The feedwater flow to the steam generators is reduced or terminated, resulting in a decrease in the shell-side fluid inventory. Moreover, fluid from the faulted steam generator can be expelled through the broken pipe, thereby eliminating the capability of the steam generator to remove heat from the RCS. A broken feedwater line may also prevent the addition of main feedwater to the intact steam generator.

The feedwater line break is one of the events which defines the required minimum capacity of the auxiliary feedwater system for removing core residual heat following reactor trip. If sufficient heat removal capability is not provided, core residual heat following reactor trip could raise the RCS coolant temperature to the extent that the resulting fuel damage would compromise the maintenance of a coolable geometry of the core, and result in potential radioactive releases. For St. Lucie Unit 2, the analysis used to justify the auxiliary feedwater requirements for a postulated feedwater line break is presented in UFSAR Chapter 10.4.9A.

A feedwater line break during full-power operation may also cause a short-term pressure increase in both the RCS and main steam system challenging the integrity of the RCS and MSS pressure boundaries.

A feedwater line break is classified as an ANS Condition III or IV event, an infrequent or limiting fault, depending on break size.

Method of Analysis

The feedwater line break analysis assumes a break in a feedwater line at the steam generator inlet nozzle. Such a break results in an uncontrolled discharge of fluid from the steam generator. A break upstream of the feedwater line check valve would affect the RCS only as a loss of normal feedwater.

This accident is analyzed: (1) to confirm that the pressurizer safety valves (PSVs) and MSSVs are adequately sized to prevent overpressurization of the primary RCS and MSS, respectively; and (2) to ensure that the DNB design basis is satisfied. Chapter 10.4.9A of the UFSAR demonstrates the adequacy of the auxiliary feedwater system in removing long-term decay heat.

The feedwater line break transient is analyzed by employing the detailed digital computer code RETRAN (References 1 and 2). The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and MSSVs. The code computes pertinent plant variables including temperatures, pressures, and power level.

The event is analyzed to conservatively meet Condition II acceptance criteria. Four separate cases are analyzed, one ensures that the peak primary RCS pressure remains below 110% of the design limit (2750 psia) for breaks of less than 0.2 ft^2 with no loss of offsite power, one ensures that the peak primary RCS pressure remains below 120% of the design limit (3000 psia) for breaks with a loss of offsite power, one confirms that the peak MSS pressure remains below 110% of the steam generator shell design pressure (1100 psia), and the final case is performed to address DNB concerns. While not required by the licensing basis, all break sizes with offsite power available have been shown to meet 110% of the design limit (2750 psia) for analysis simplification . The major assumptions for these cases are summarized as follows.

In order to give conservative results in calculating the maximum RCS and MSS pressures during the transient, the following assumptions are made:

1. The initial reactor power is assumed to be at its maximum value plus uncertainty, the initial RCS flow rate is assumed at a value consistent with the thermal design flow rate and the initial RCS pressure is assumed at a value consistent with minimum value allowed by the plant technical specifications minus the pressure measurement uncertainty.

2. For maximum RCS pressure, the RCS temperature is assumed to be at low-Tavg conditions minus uncertainty. For maximum MSS pressure, the RCS temperature is assumed to be at high-Tavg conditions plus uncertainty.

3. For maximum RCS pressure, the initial steam generator tube plugging level is assumed to be at the maximum plugging level. For maximum MSS pressure, the initial steam generator tube plugging level is assumed to be at the minimum plugging level.

4. The initial steam generator water level is assumed to be at the minimum water level, consistent with the low-level alarm setpoint minus the steam generator level measurement uncertainty.

5. The high pressurizer pressure and low steam pressure reactor trip setpoints for adverse conditions are assumed. The Low Steam Generator Level reactor trip is not credited.

6. The feedline break is assumed to occur at the physical inlet nozzle location on the steam generator.

7. An fL/D of 0 (zero) is assumed for the break and the blowdown quality is calculated by the RETRAN code.

8. A break size spectrum is analyzed to determine the limiting size with respect to RCS and MSS overpressurization.

9. Minimum reactivity feedback is assumed to maximize the energy input to the primary coolant.

10. No credit is taken for the effect of the pressurizer spray in reducing or limiting primary coolant pressure. Pressurizer safety valves are available, but are modeled assuming a +3% setpoint tolerance. Finally, the PORV is not considered since it would actuate after reactor trip on high pressurizer pressure.

The initial conditions are summarized in Table 5.1.0-2.

In order to give conservative results in calculating the minimum DNBR during the transient, the following assumptions are made:

The initial reactor power and RCS temperature are assumed to be at their nominal values, the initial RCS flow rate is assumed at a value consistent with the minimum measured flow rate and the initial RCS pressure is assumed at a value consistent with the lowest nominal value allowed by the plant technical specifications. Uncertainties in initial conditions are included in determining the DNBR limit value consistent with the use of RTDP (Reference 3).

The initial steam generator tube plugging level is assumed to be at the maximum plugging level. The initial steam generator water level is assumed to be at the minimum water level, consistent with the low-level alarm setpoint minus the steam generator level measurement uncertainty.

The high pressurizer pressure and low steam pressure reactor trip setpoints for adverse conditions are assumed. The low steam generator level reactor trip is not credited.

The feedline break is assumed to occur at the physical inlet nozzle location on the steam generator.

An fL/D of 0 (zero) is assumed for the break and the blowdown quality is calculated by the RETRAN code.

A break size spectrum is analyzed to determine the limiting size with respect to minimum DNBR.

Minimum reactivity feedback is assumed to maximize the energy input to the primary coolant.

Credit is taken for the effect of the pressurizer spray in reducing primary coolant pressure and delaying reactor trip on high pressurizer pressure. Pressurizer safety valves are also available and are modeled assuming a -3% setpoint tolerance. The PORV is assumed to actuate once reaching the high pressurizer pressure reactor trip setpoint.

The initial conditions are summarized in Table 5.1.0-2.

The feedline break methodology also considers the possibility of a loss-of-offsite-power (LOOP) event. For this analysis, the LOOP is assumed to occur coincident with the reactor trip breaker opening. For the RCS pressure cases, peak pressure occurs soon after reactor trip, and assuming the reactor coolant pumps (RCPs) coastdown coincident with the reactor trip breaker opening is limiting. For MSS pressure cases, losing the RCPs retards heat transfer to the intact steam generator, leading to a lower peak secondary-side pressure. For the DNBR case with LOOP, the results of the "Pre-Trip Steam System Piping Failure with Loss of Offsite Power at Time of Reactor Trip Breaker Opening" (Section 5.1.5) analysis are bounding because there would be greater cooling of the RCS with a steamline break, which would result in lower pressure and high power for DNBR evaluation.

Results

The feedwater line break event was analyzed assuming the plant to be initially operating at full power at beginning of cycle (BOC) (minimum feedback reactivity coefficients) with no credit taken for the pressurizer spray to determine the primary RCS pressure response. Further, the low steam generator level reactor trip function was not credited. The break spectrum from 0.25 ft^2 to 0.375 ft^2 was analyzed for cases with offsite power available to assure that the maximum RCS pressure case would be captured. Based on the results of these calculations, it is seen that breaks smaller than 0.25 ft^2 (including 0.2 ft^2) would result in less limiting RCS pressure. Figures 5.1.12-1 through 5.1.12-7 show the transient results for the limiting break case with offsite power available, 0.28 ft^2. In this case, the PSVs are actuated and maintain the primary RCS pressure below 110% of the design value. Table 5.1.12-1 summarizes the results of the break spectrum analysis with offsite power available and Table 5.1.12-4 provides the sequence of events and limiting conditions for the 0.28 ft^2 case with offsite power available. The break spectrum from 0.20 ft^2 to 0.375 ft^2 was analyzed for cases with a loss of offsite power to assure that the maximum RCS pressure case would be captured. Figures 5.1.12-1a through 5.1.12-7a show the transient results for the limiting break case with a loss of offsite power available, 0.28 ft^2. In this case, the PSVs are actuated and maintain the primary RCS pressure below 120% of the design value. The maximum pressure trends also demonstrate that all breaks sizes less than 0.2 ft^2 will remain below 110% of the design value with any flow reduction (including 6.9 kV fast bus transfer failure). Table 5.1.12-1a summarizes the results of the break spectrum analysis with a loss of offsite power and Table 5.1.12-4a provides the sequence of events and limiting conditions for the 0.28 ft^2 case with a loss of offsite power.

Table 5.1.12-2 summarizes the break spectrum results for the feedwater line break event at BOC (minimum feedback reactivity coefficients) assuming 0% SGTP to determine the secondary MSS pressure response. Further, the low steam generator level reactor trip function was not credited. The break spectrum was analyzed from 0.005 ft^2 to 0.375 ft^2 to assure that the maximum MSS pressure case would be captured. The limiting break size was found to be 0.05 ft^2. The MSS pressure increases, resulting in opening the MSSVs, then decreases rapidly following reactor trip. The MSSVs actuate to limit the MSS pressure below 110% of the steam generator shell design pressure. Table 5.1.12-5 provides the sequence of events and limiting conditions for the 0.05 ft^2 case, and Figures 5.1.12-8 through 5.1.12-14 show the transient results. (Note: Due to the small break size, the MSS pressure and break flow response for the 0.05 ft^2 case is much different from those presented for the limiting RCS overpressurization and DNB cases.)

The feedwater line break DNB case is analyzed at BOC (minimum feedback reactivity coefficients) assuming full credit for the pressurizer spray to calculate the transient DNBR response. Further, the low steam generator level reactor trip function was not credited. The break spectrum was analyzed from 0.20 ft^2 to 0.375 ft^2 to assure that the limiting DNBR case would be captured. The limiting break size was found to be 0.25 ft^2. The minimum DNBR remains well above the safety analysis limit value. Table 5.1.12-3 summarizes the break spectrum results, which demonstrates this conclusion. Table 5.1.12-6 summarizes the sequence of events and limiting conditions for the limiting 0.25 ft^2 case. Figures 5.1.12-15 through 5.1.10-22 show the transient responses for the 0.25 ft^2 case.

Conclusion

The results of the analyses show that the plant design is such that a feedwater line break presents no hazard to the integrity of the primary RCS or MSS by meeting all applicable Condition II acceptance criteria. Pressure relieving devices that have been incorporated into the plant design are adequate to limit the maximum pressures to within the safety analysis limits, i.e., 2750 psia or 3000 psia, as appropriate, for the primary RCS and 1100 psia for the MSS. The integrity of the core is maintained by operation of the RPS, i.e., the minimum DNBR is maintained above the safety analysis limit value of 1.42. Thus, no core safety limit will be violated as a result of implementing up to 30% steam generator tube plugging or transitioning to the WCAP-9272 methodology.

References

1. WCAP-14882-P-A, Rev. 0, "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses."

2. EPRI NP-1850-CCM, "Validation and Verification of the MTR-PC Thermohydraulic Package."

3. WCAP-11397, "Revised Thermal Design Procedure," April 1989.

Table 5.1.12-1
Feedwater Line Break RCS Overpressurization Case Results
(With Offsite Power Available)

Break Size (ft^2)	Max RCS Pressure (psia)
0.375	2640
0.35	2651
0.325	2670
0.30	2723
0.29	2736
0.28	2739
0.27	2733
0.25	2706
110% of Design Pressure Limit	2750

Table 5.1.12-1a
Feedwater Line Break RCS Overpressurization Case Results
(With a Loss of Offsite Power)

Break Size (ft^2)	Max RCS Pressure (psia)
0.375	2698
0.35	2704
0.32	2715
0.29	2780
0.28	2788
0.27	2758
0.24	2744
0.20	2730
120% of Design Pressure Limit	3000

Table 5.1.12-2 Feedwater Line Break MSS Overpressurization Case Results	
Break Size (ft^2)	**Max MSS Pressure (psia)**
0.375	991
0.300	1039
0.250	1063
0.200	1070
0.150	1079
0.100	1085
0.050	1090
0.010	1089
0.005	1089
110% of Design Pressure Limit	1100

Table 5.1.12-3 Feedwater Line Break DNBR Case Results	
Break Size (ft^2)	**Min DNBR**
0.375	1.74
0.30	1.64
0.25	1.58
0.20	1.64
MDNBR Limit	1.42

Table 5.1.12-4 Sequence of Events and Transient Results Feedwater Line Break Limiting Break Size = 0.28 ft^2 With Offsite Power Available	
Without Pressurizer Pressure Control (for Primary RCS Overpressure)	
Event	**Time (seconds)**
Initiation of Event	0.01
Manual Feedwater Isolation (both loops)	0.01
Reactor Trip on Low Steam Pressure	30.4
Reactor Trip (Breakers open)	30.8
Rod Motion Begins (0.74 seconds following Breaker opening)	31.5
Time of Peak RCS Pressure	33.2
Peak RCS Pressure	2739 psia
RCS Pressure Limit	2750 psia

Table 5.1.12-4a Sequence of Events and Transient Results Feedwater Line Break Limiting Break Size = 0.28 ft^2 With a Loss of Offsite Power	
Without Pressurizer Pressure Control (for Primary RCS Overpressure)	
Event	**Time (seconds)**
Initiation of Event	0.01
Manual Feedwater Isolation (both loops)	0.01
Reactor Trip on Low Steam Pressure	30.4
Reactor Trip (breakers open)	30.8
Loss of Offsite Power (all four rcps coast down)	30.8
Rod Motion Begins (0.74 seconds following breaker opening)	31.5
Time of Peak RCS Pressure	33.5
Peak RCS Pressure	2788 psia
RCS Pressure Limit	3000 psia

Table 5.1.12-5 Sequence of Events and Transient Results Feedwater Line Break Limiting Break Size = 0.05 ft^2	
Without Pressurizer Pressure Control (for Main Steam System Overpressure)	
Event	**Time (seconds)**
Initiation of Event	0.01
Manual Feedwater Isolation (both loops)	0.01
Reactor Trip on High Pressurizer Pressure	36.7
Reactor Trip (Breakers open)	37.1
Rod Motion Begins (0.74 seconds following Breaker opening)	37.8
Time of Peak MSS Pressure	41.2
Peak MSS Pressure	1090 psia
MSS Pressure Limit	1100 psia

Table 5.1.12-6 Sequence of Events and Transient Results Feedwater Line Break Limiting Break Size = 0.25 ft^2	
With Pressurizer Pressure Control (for Minimum DNB))	
Event	**Time (seconds)**
Initiation of Event	0.01
Manual Feedwater Isolation (both loops)	0.01
Reactor Trip on Low Steam Pressure	40.4
Reactor Trip (breakers open)	40.8
Rod Motion Begins (0.74 seconds following breaker opening)	41.5
Time of Minimum DNBR	60.9
Minimum DNBR Value	1.58
DNBR Limit	1.42

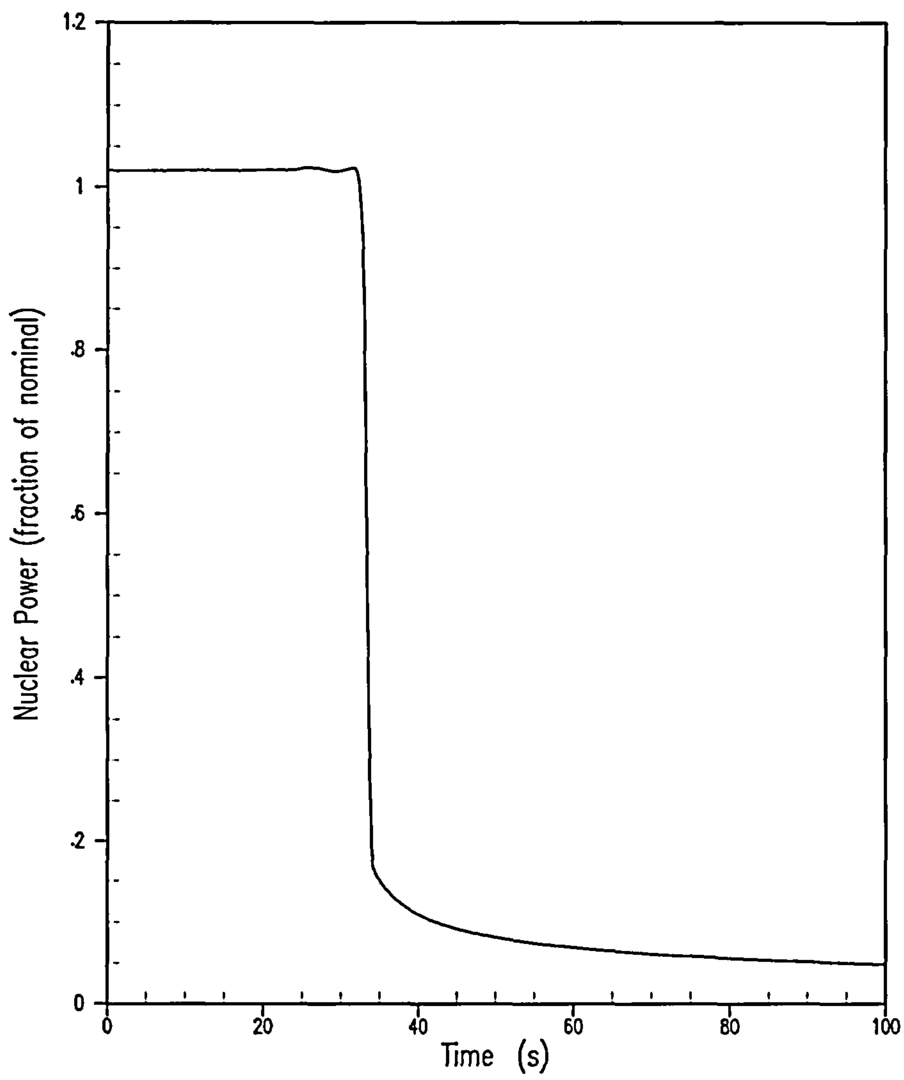


Figure 5.1.12-1 Feedwater Line Break RCS Overpressure Case With No LOOP Limiting Break Size = 0.28 ft^2 Nuclear Power

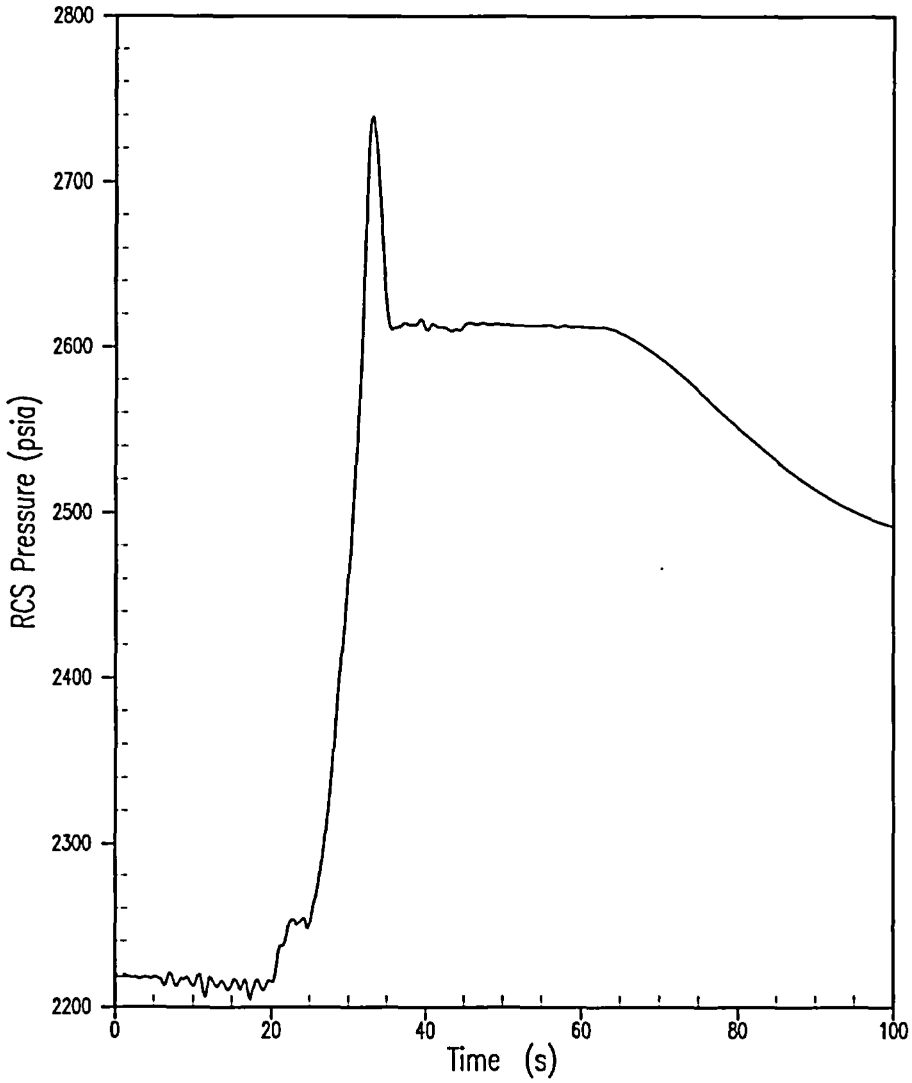


Figure 5.1.12-2 Feedwater Line Break RCS Overpressure Case With No LOOP Limiting Break Size = 0.28 ft^2 RCS Pressure

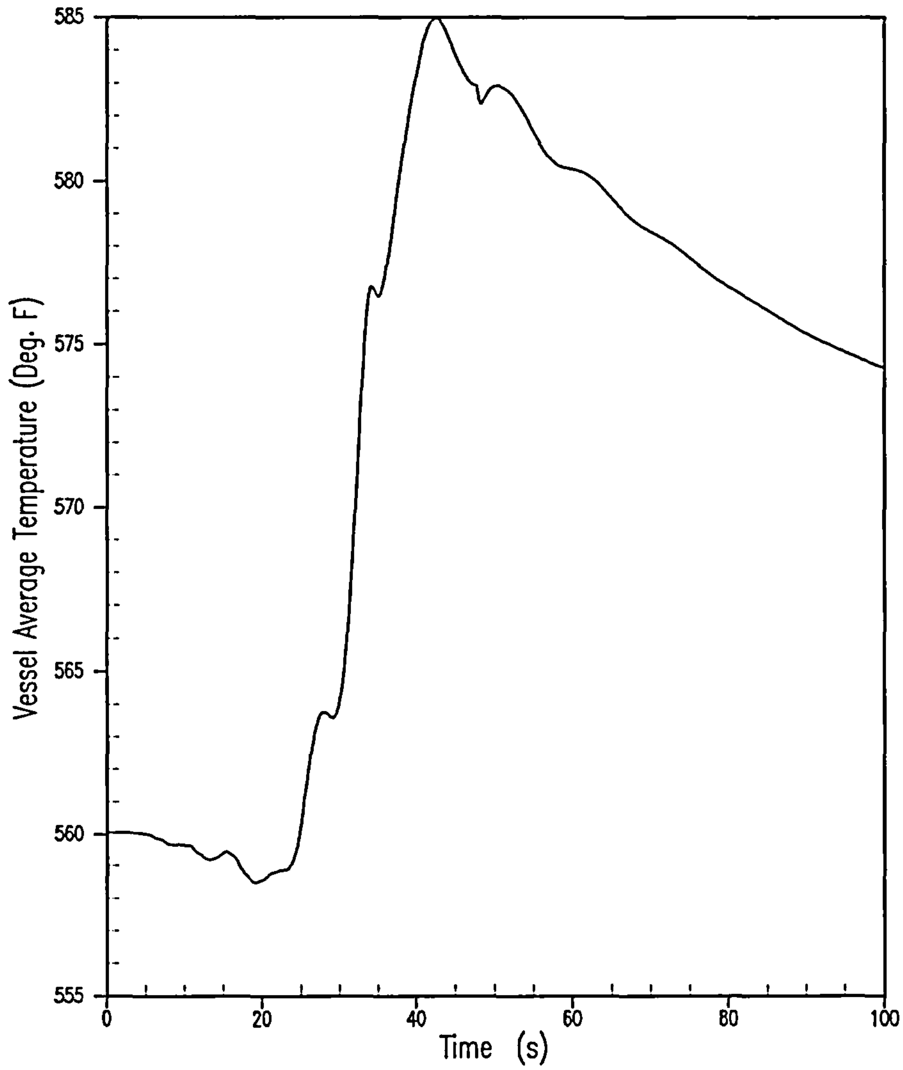


Figure 5.1.12-3 Feedwater Line Break RCS Overpressure Case With No LOOP Limiting Break Size = 0.28 ft^2 Vessel Average Temperature

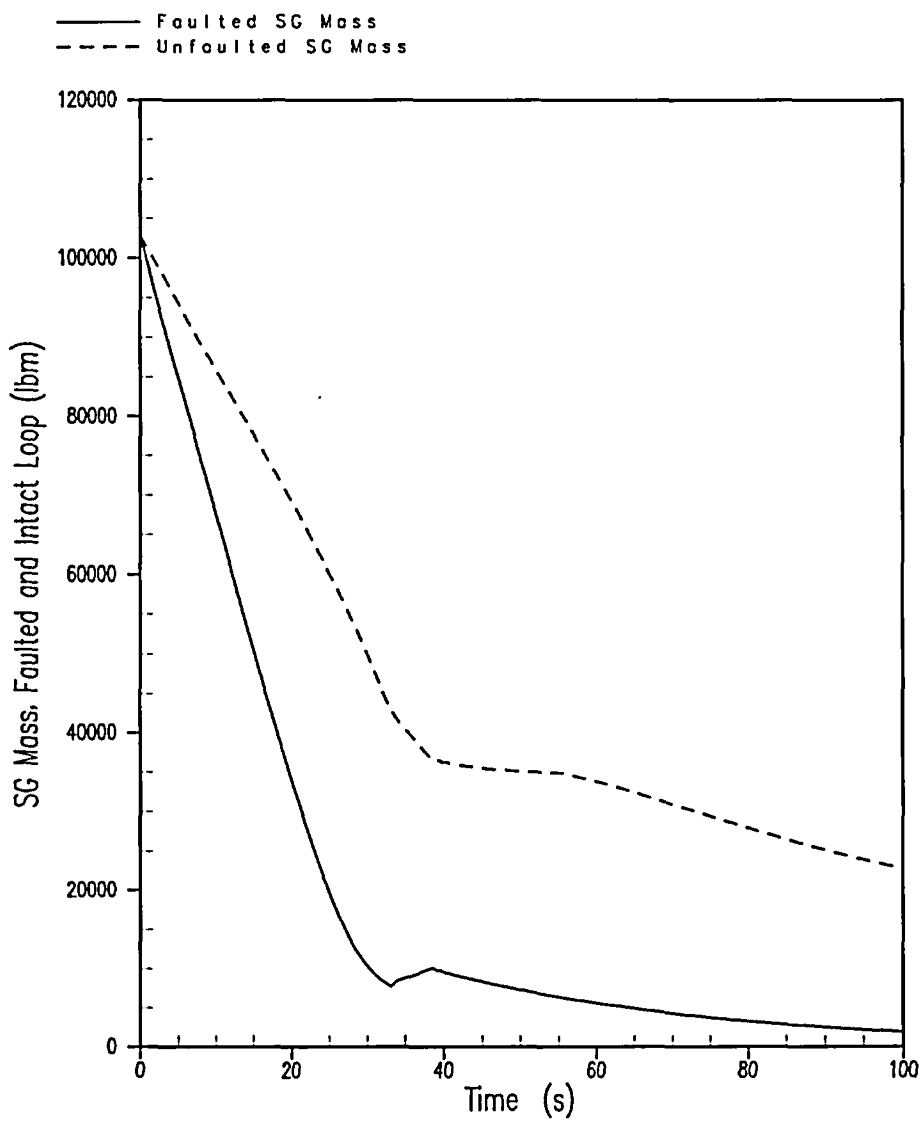


Figure 5.1.12-4 Feedwater Line Break RCS Overpressure Case With No LOOP Limiting Break Size = 0.28 ft^2 SG Mass, Faulted and Intact Loop

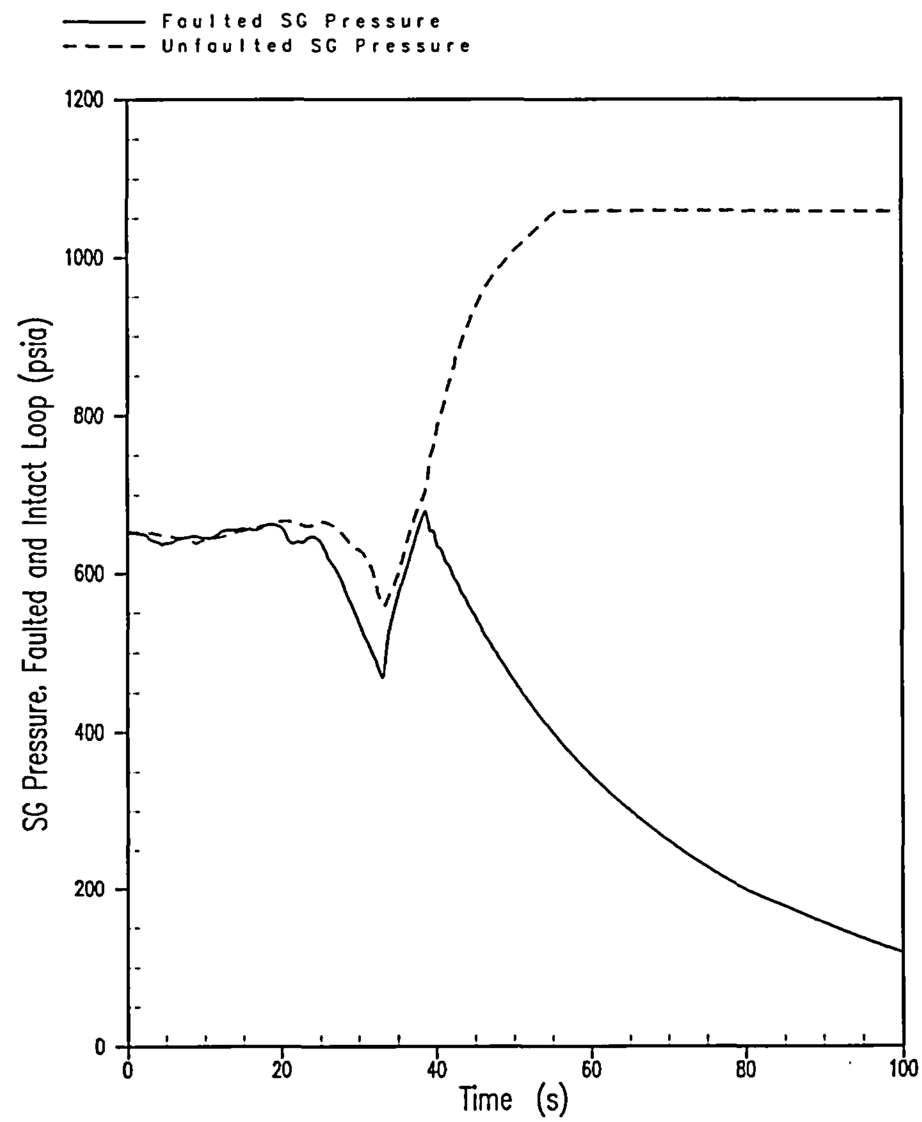


Figure 5.1.12-5 Feedwater Line Break RCS Overpressure Case With No LOOP Limiting Break Size = 0.28 ft^2 SG Pressure, Faulted and Intact Loop

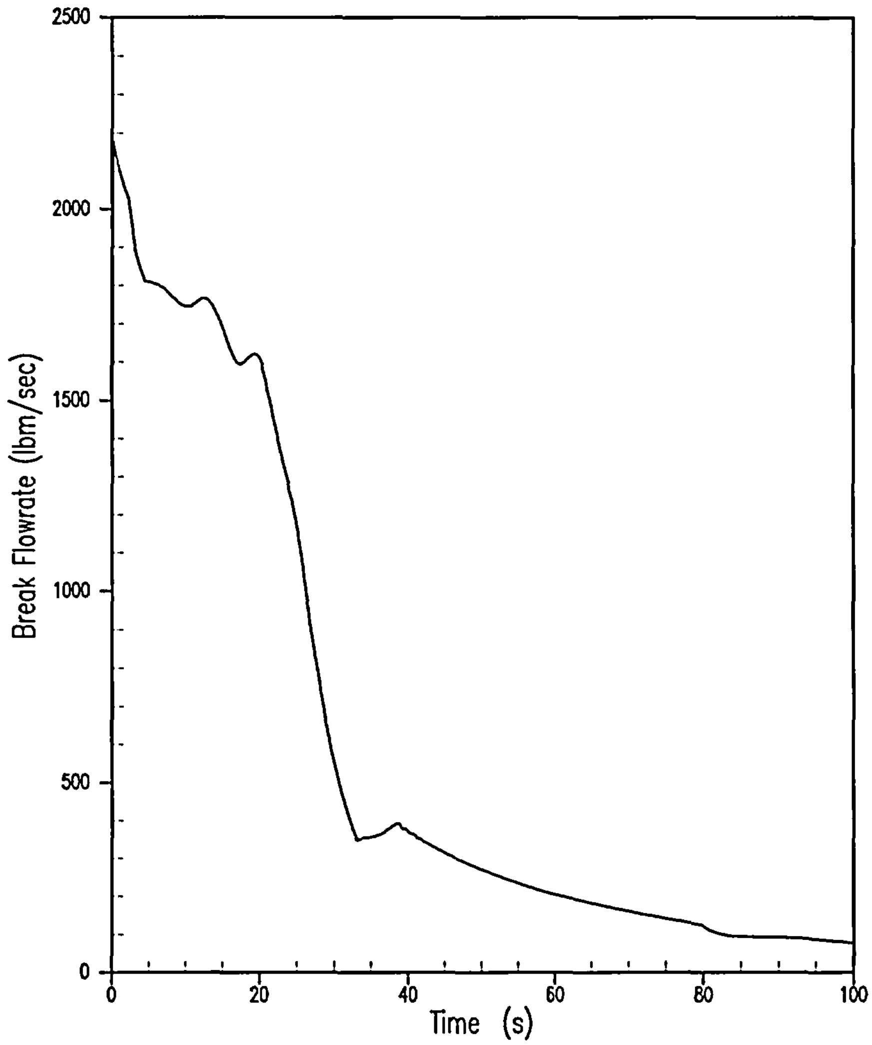


Figure 5.1.12-6 Feedwater Line Break RCS Overpressure Case With No LOOP Limiting Break Size = 0.28 ft^2 Break Flowrate

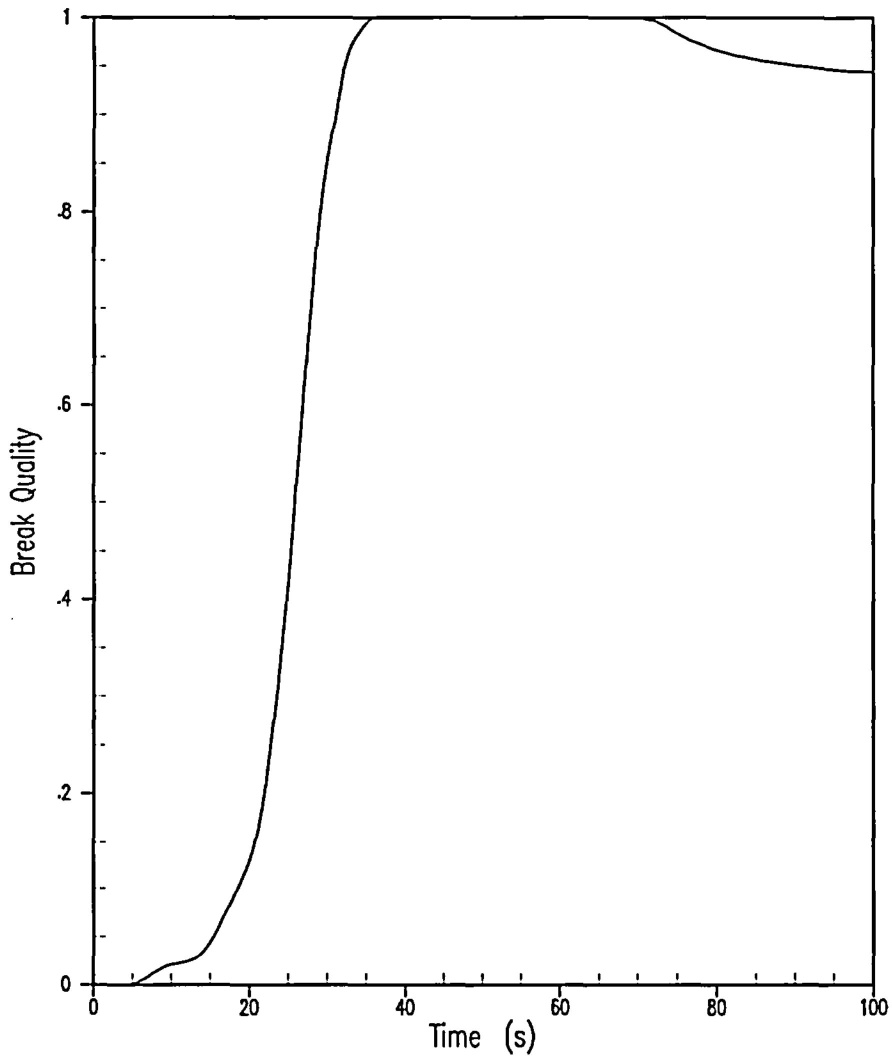


Figure 5.1.12-7 Feedwater Line Break RCS Overpressure Case With No LOOP Limiting Break Size = 0.28 ft^2 Break Quality

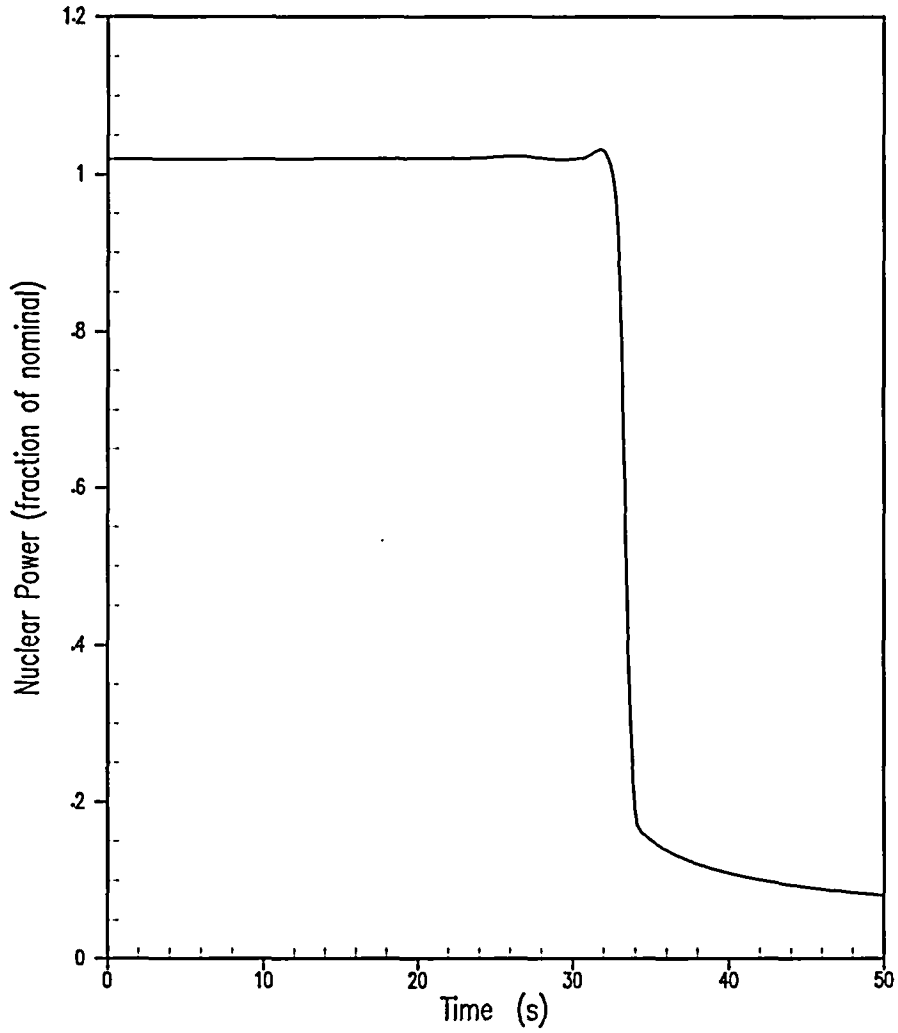


Figure 5.1.12-1a Feedwater Line Break RCS Overpressure Case With LOOP Limiting Break Size = 0.28 ft^2 - Nuclear Power

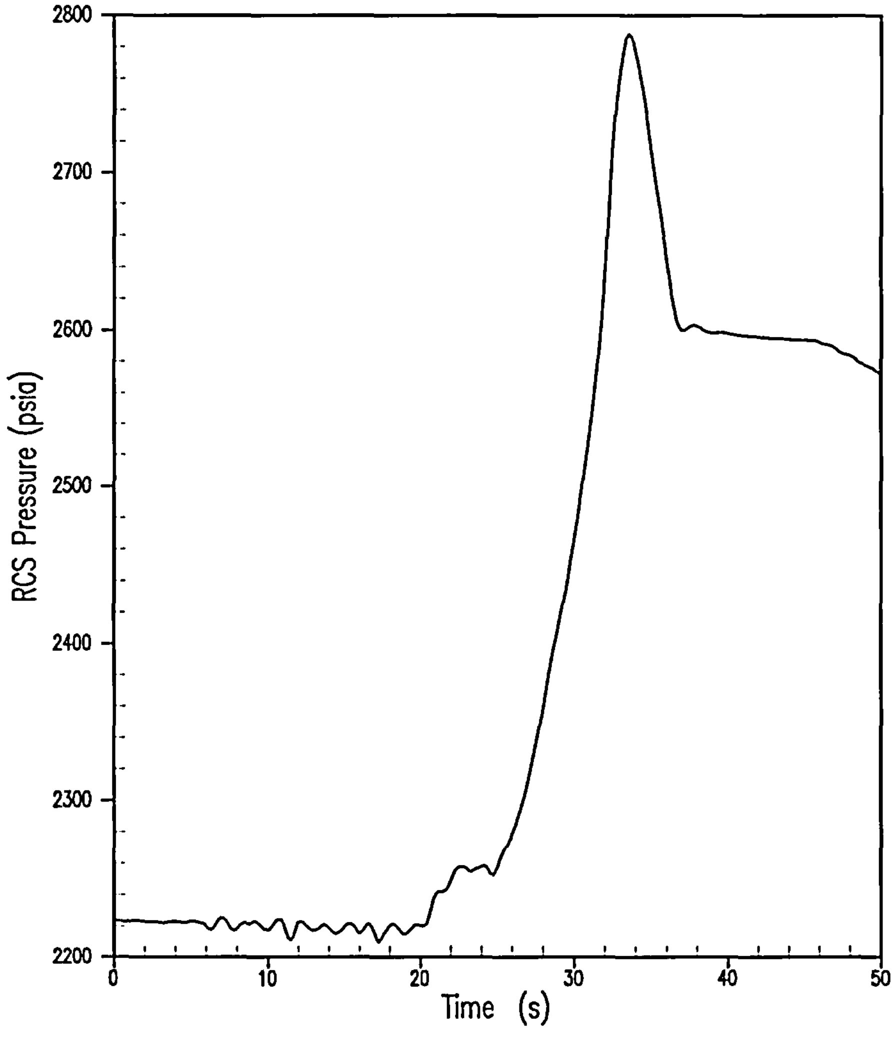


Figure 5.1.12-2a Feedwater Line Break RCS Overpressure Case With LOOP Limiting Break Size = 0.28 ft^2 - RCS Pressure

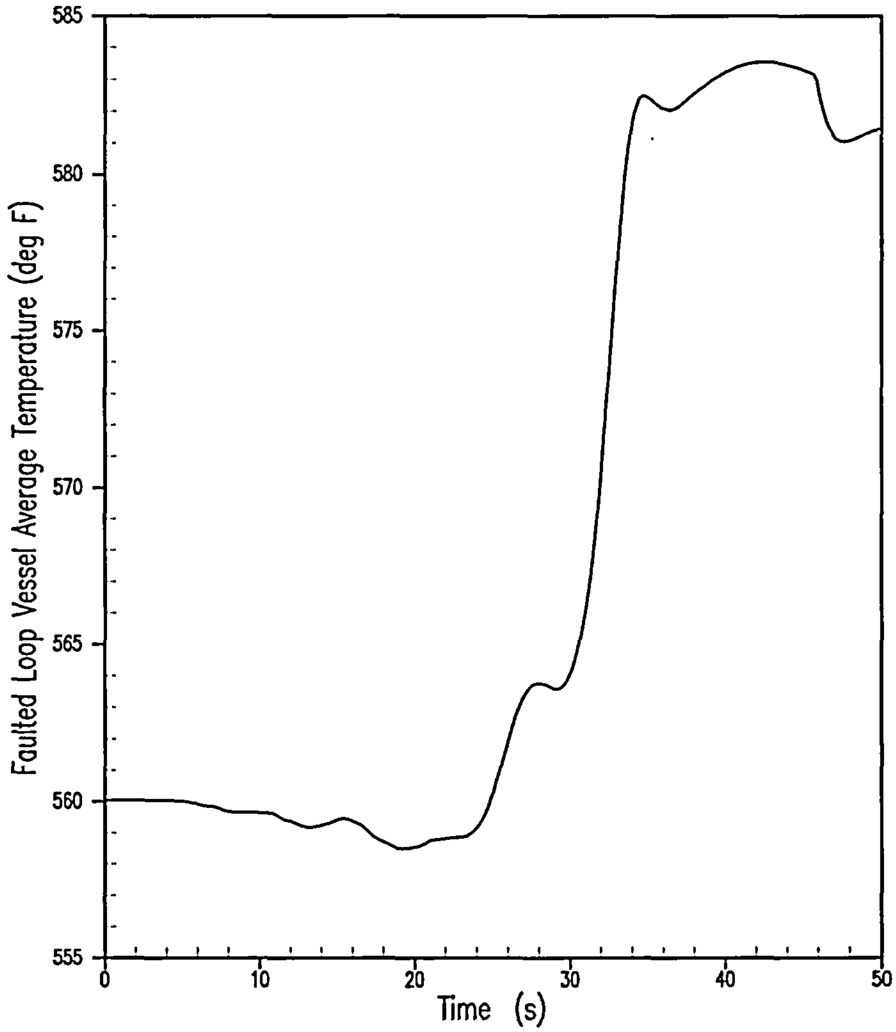


Figure 5.1.12-3a Feedwater Line Break RCS Overpressure Case With LOOP Limiting Break Size = 0.28 ft^2 - Vessel Average Temperature

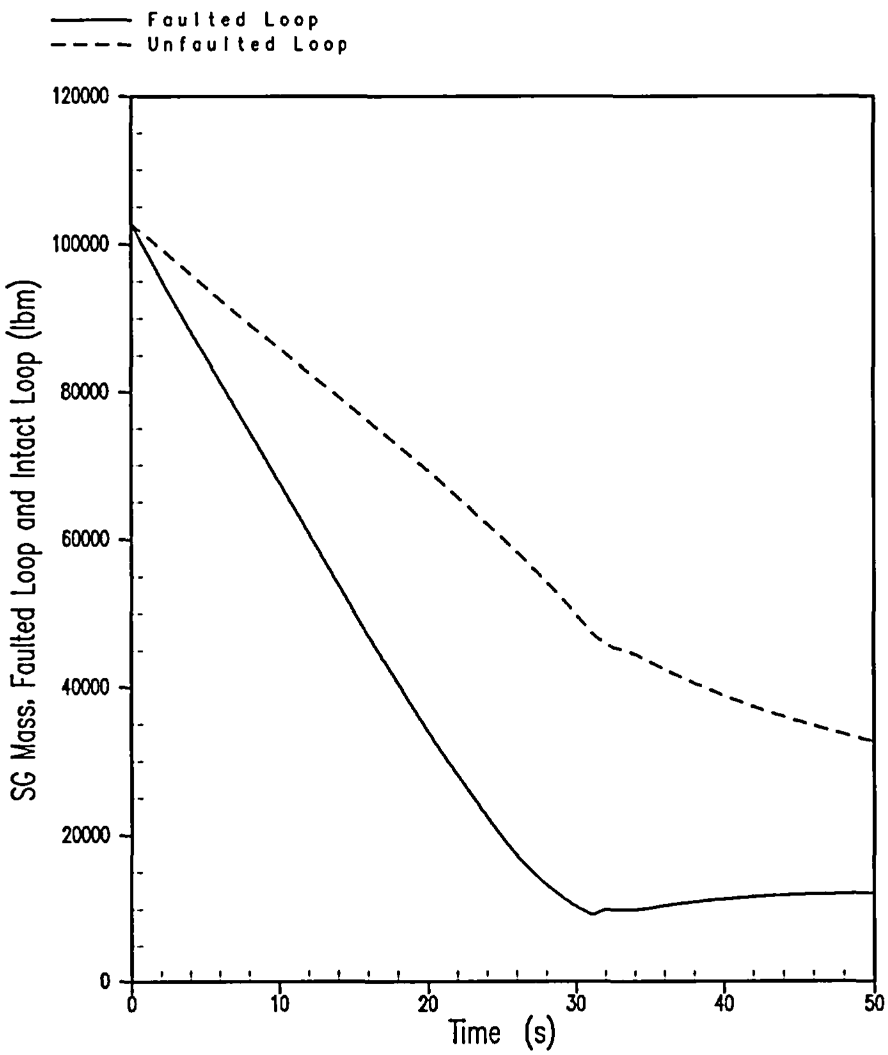


Figure 5.1.12-4a Feedwater Line Break RCS Overpressure Case With LOOP Limiting Break Size = 0.28 ft^2 - SG Mass, Faulted and Intact Loop

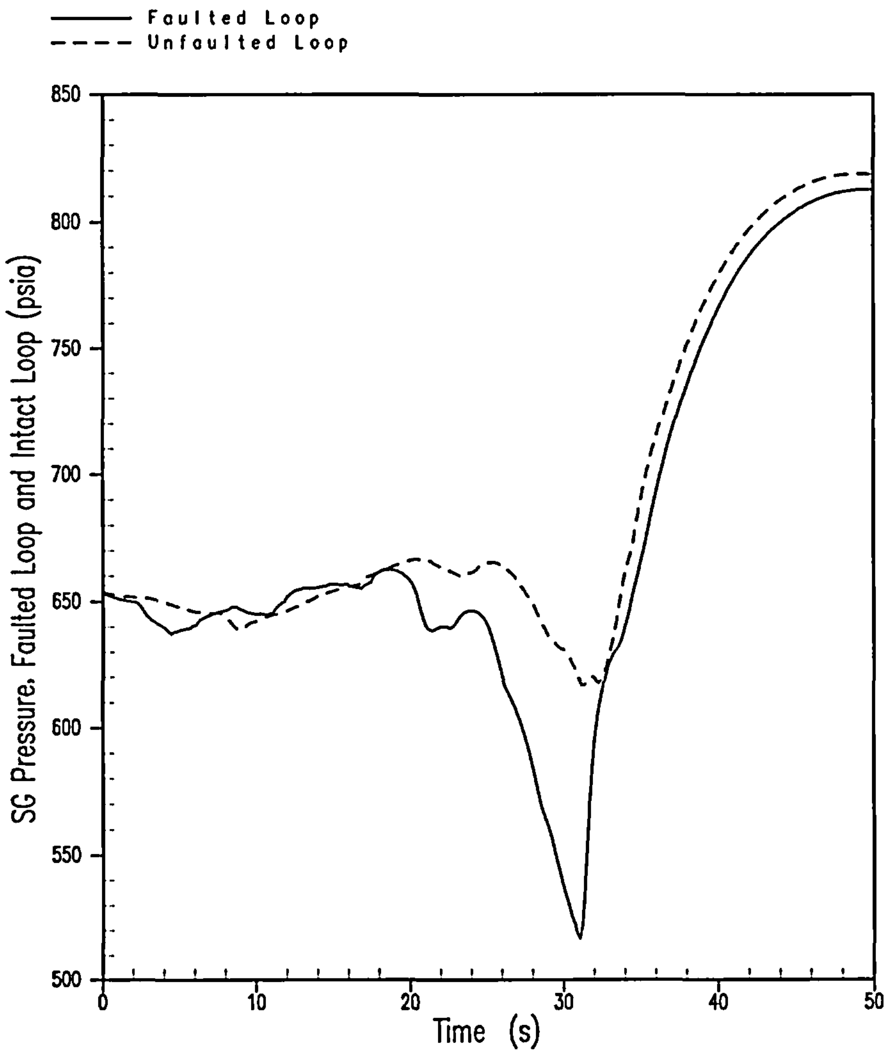


Figure 5.1.12-5a Feedwater Line Break RCS Overpressure Case With LOOP Limiting Break Size = 0.28 ft^2 - SG Pressure, Faulted and Intact Loop

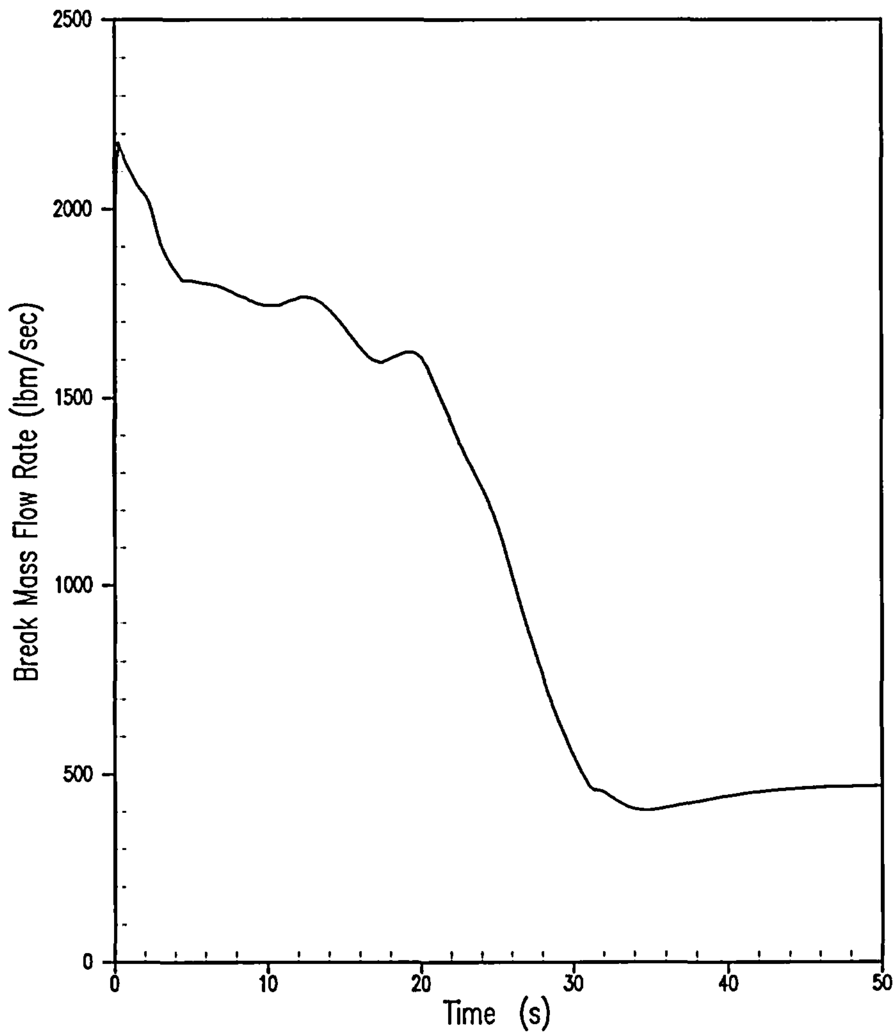


Figure 5.1.12-6a Feedwater Line Break RCS Overpressure Case With LOOP Limiting Break Size = 0.28 ft^2 - Break Flowrate

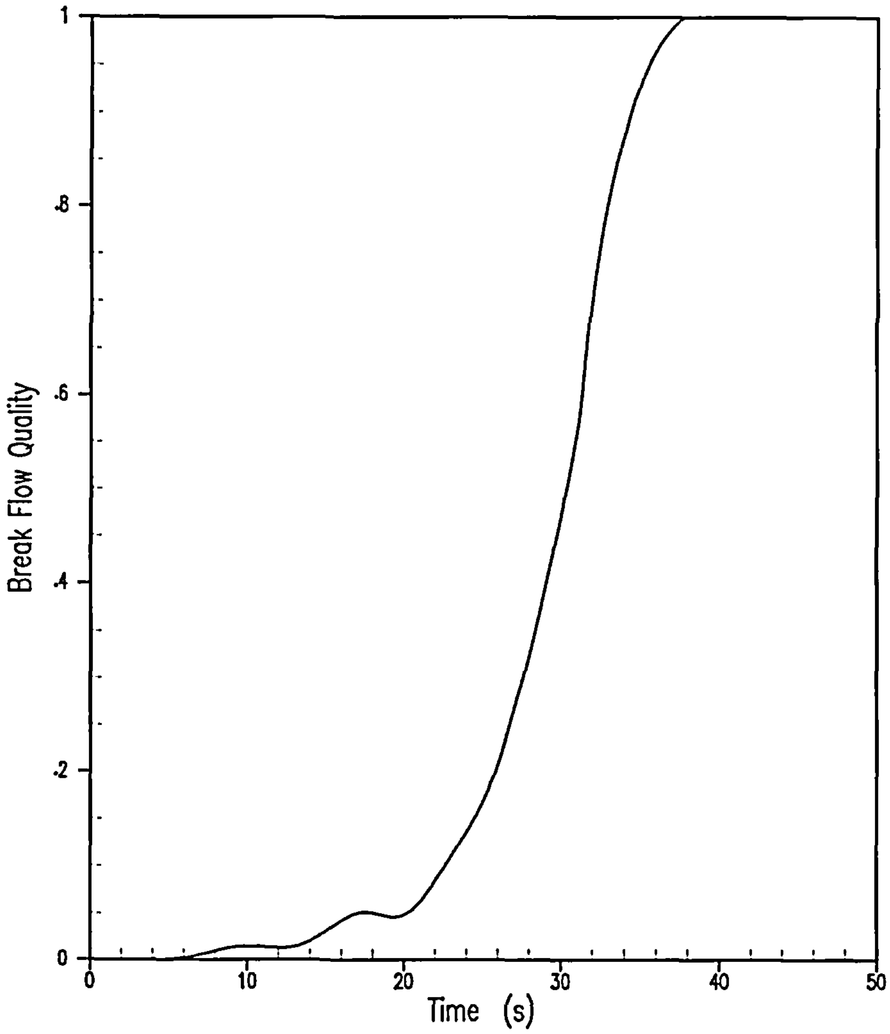


Figure 5.1.12-7a Feedwater Line Break RCS Overpressure Case With LOOP Limiting Break Size = 0.28 ft^2 - Break Quality

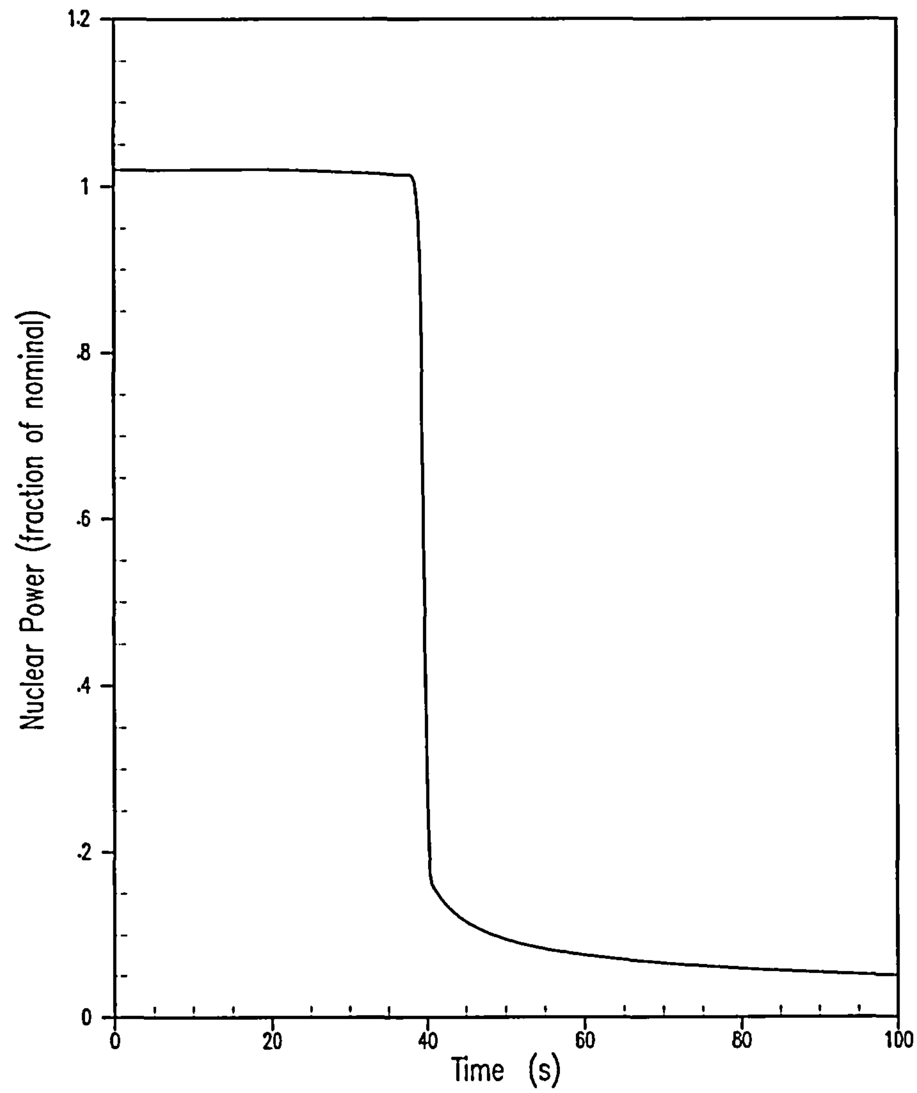


Figure 5.1.12-8 Feedwater Line Break MSS Overpressure Case Limiting Break Size = 0.05 ft^2 Nuclear Power

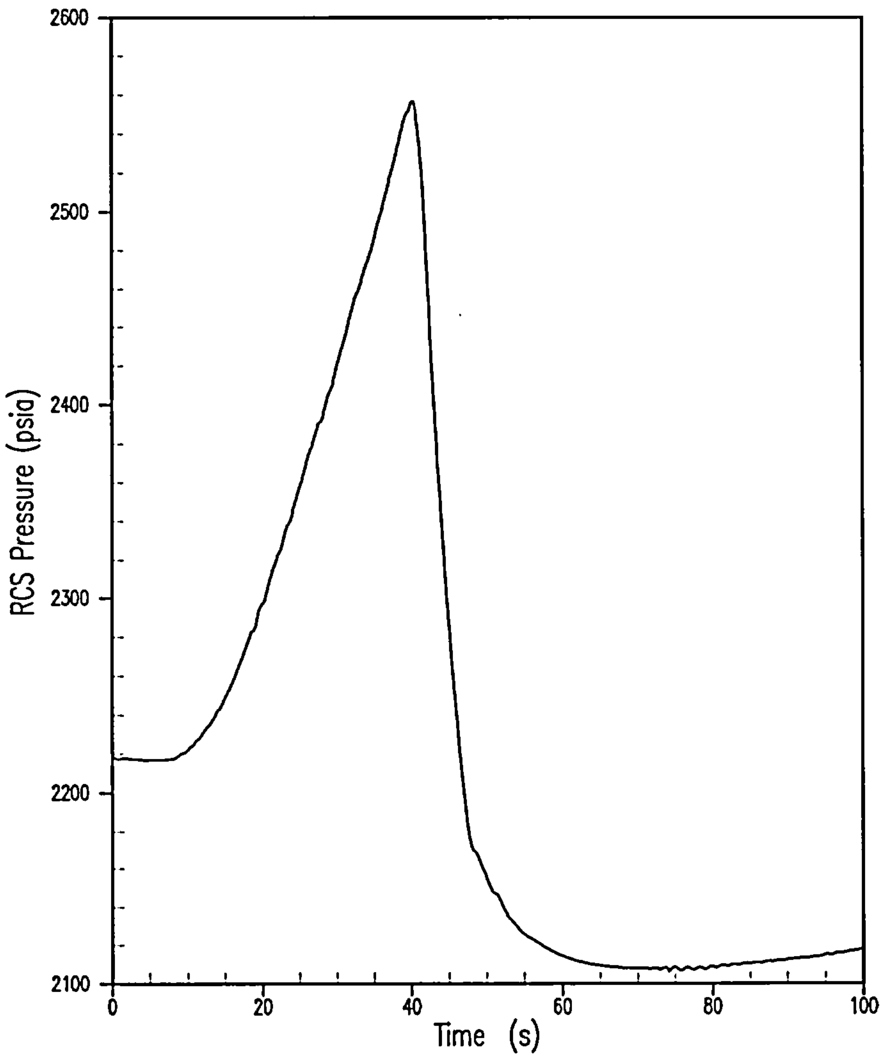


Figure 5.1.12-9 Feedwater Line Break MSS Overpressure Case
Limiting Break Size = 0.05 ft^2 RCS Pressure

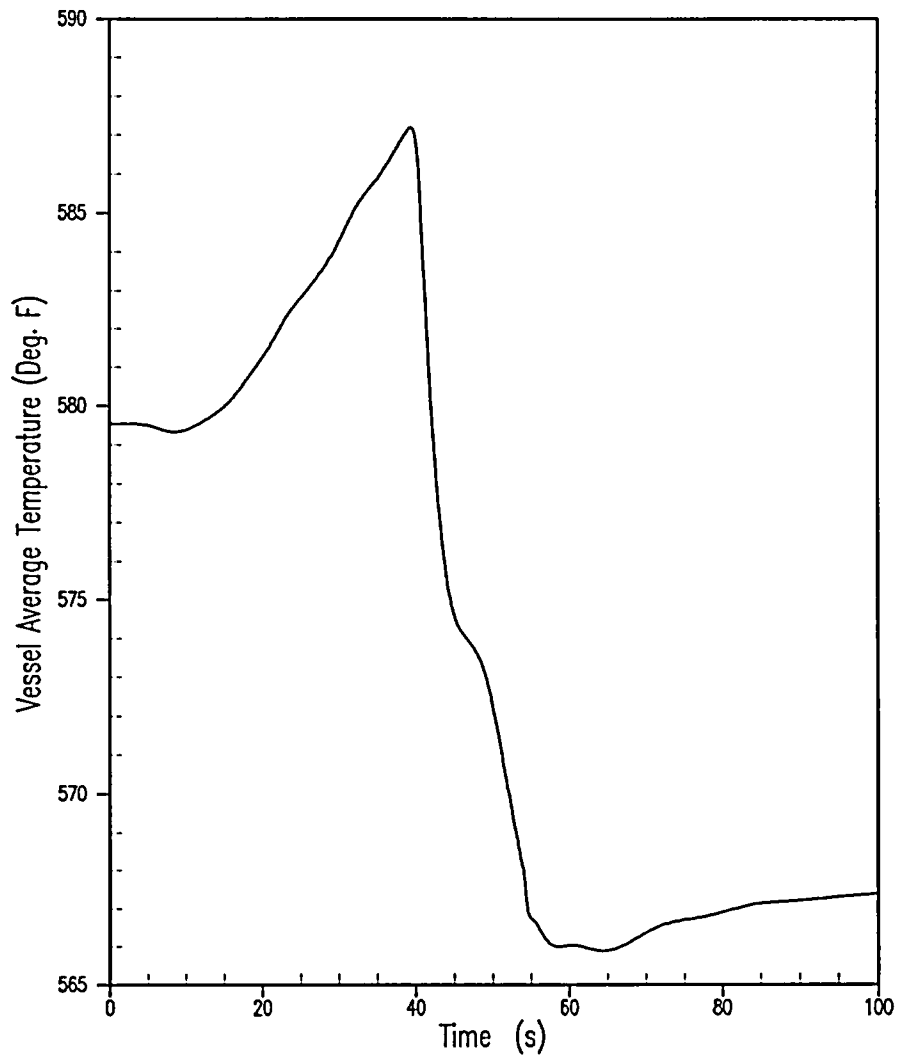


Figure 5.1.12-10 Feedwater Line Break MSS Overpressure Case Limiting Break Size = 0.05 ft^2 Vessel Average Temperature

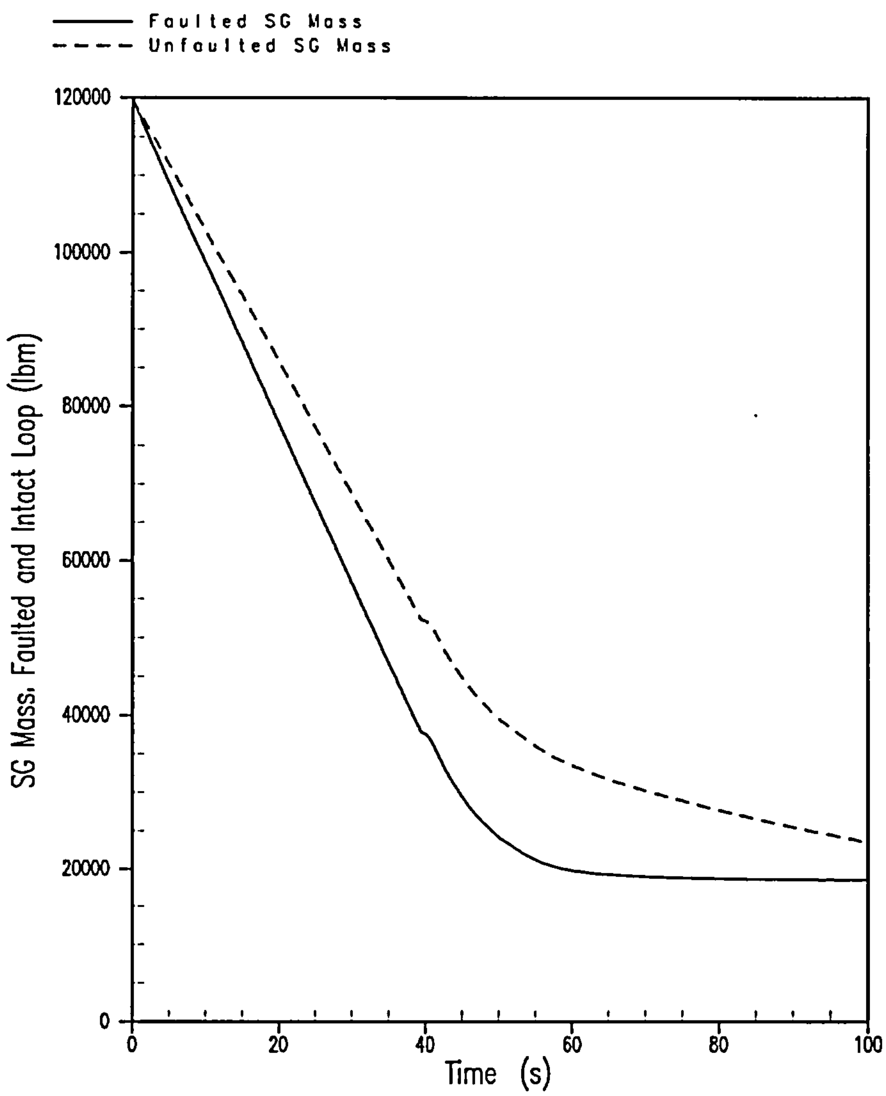


Figure 5.1.12-11 Feedwater Line Break MSS Overpressure Case Limiting Break Size = 0.05 ft^2 SG Mass, Faulted and Intact Loop

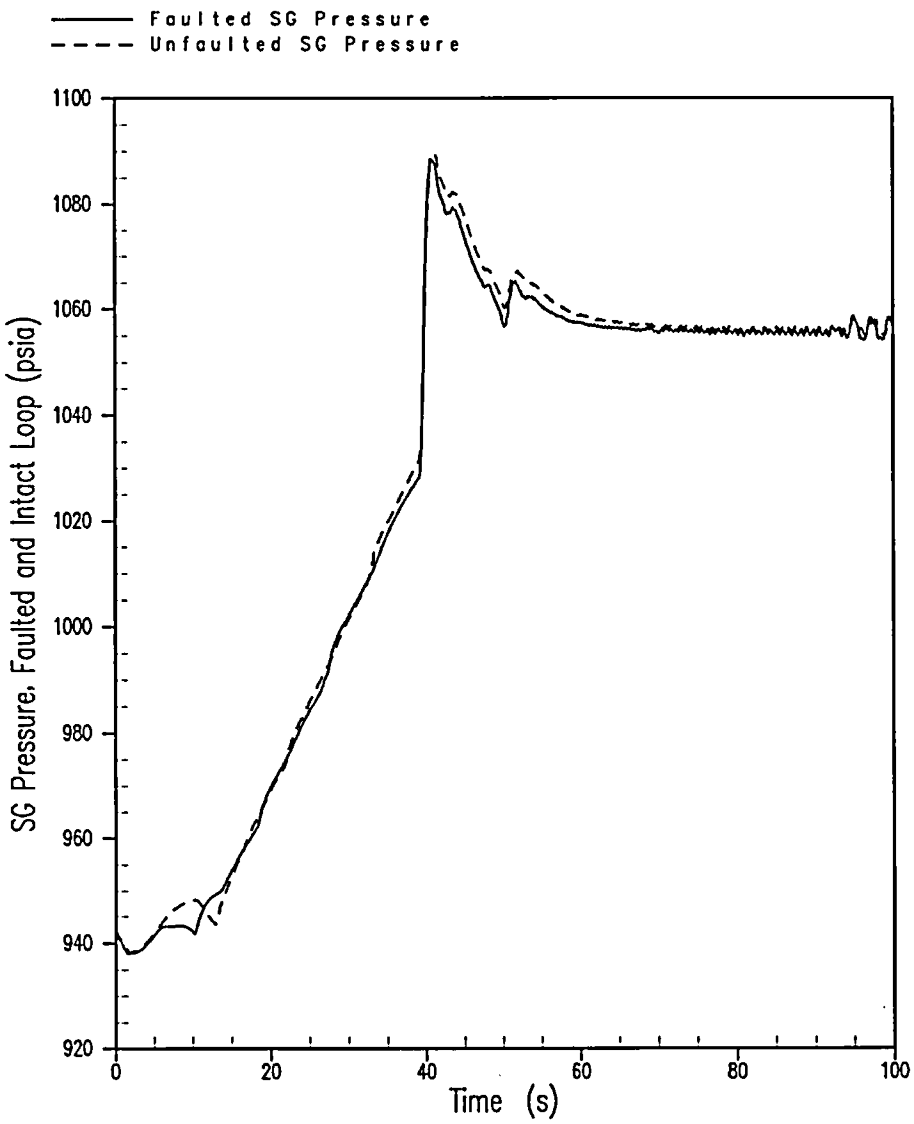


Figure 5.1.12-12 Feedwater Line Break MSS Overpressure Case Limiting Break Size = 0.05 ft^2 SG Pressure, Faulted and Intact Loop

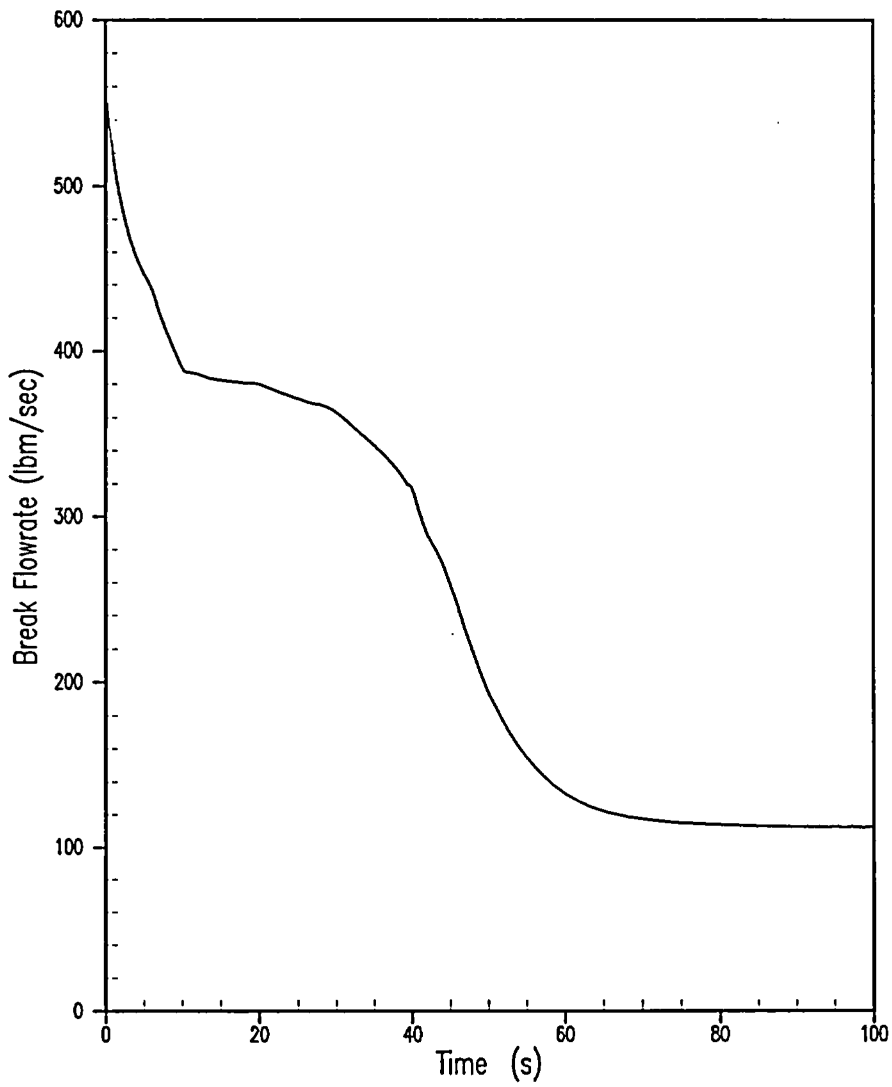


Figure 5.1.12-13 Feedwater Line Break MSS Overpressure Case Limiting Break Size = 0.05 ft^2 Break Flowrate

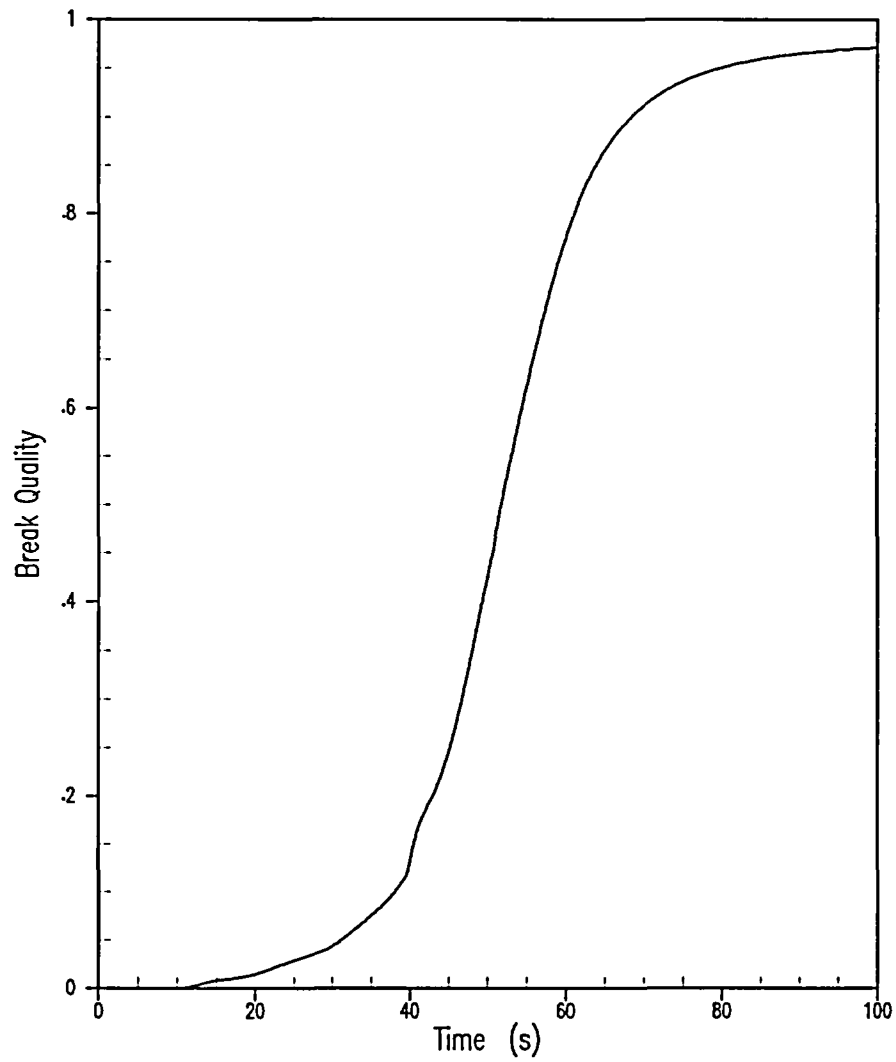


Figure 5.1.12-14 Feedwater Line Break MSS Overpressure Case Limiting Break Size = 0.05 ft^2 Break Quality

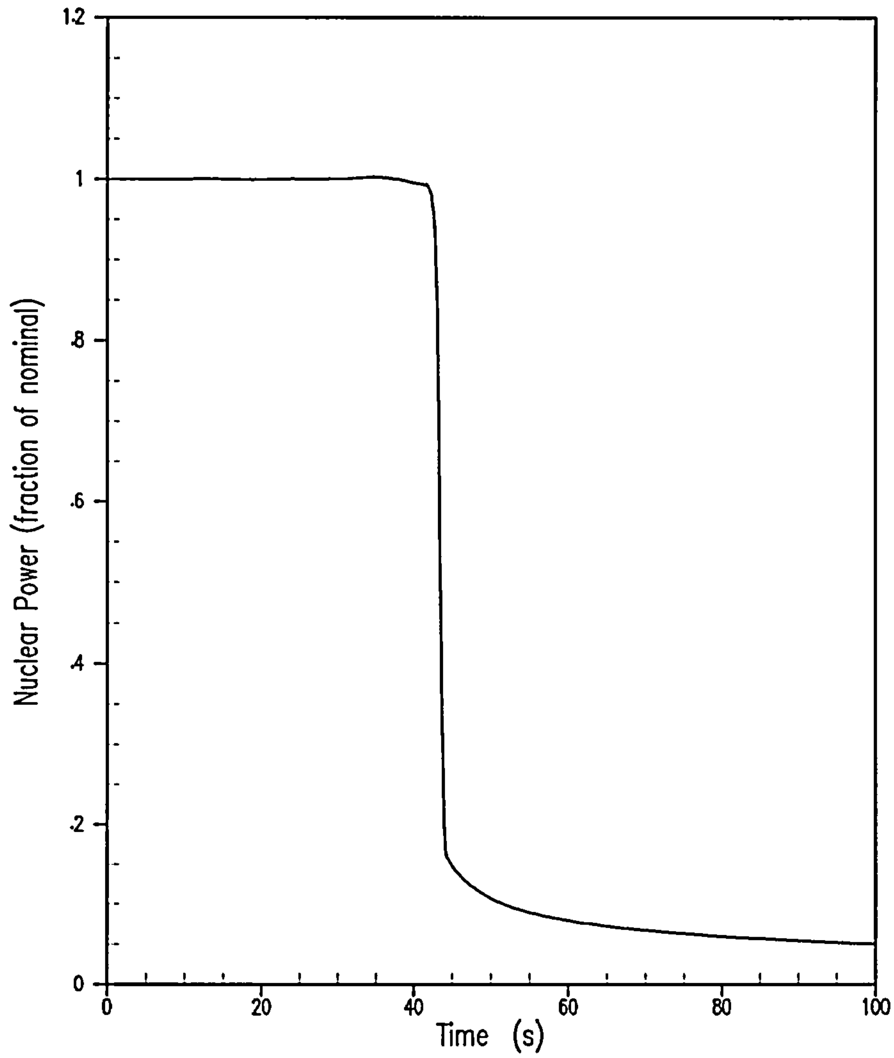


Figure 5.1.12-15 Feedwater Line Break DNB Case Limiting Break Size = 0.25 ft^2 Nuclear Power

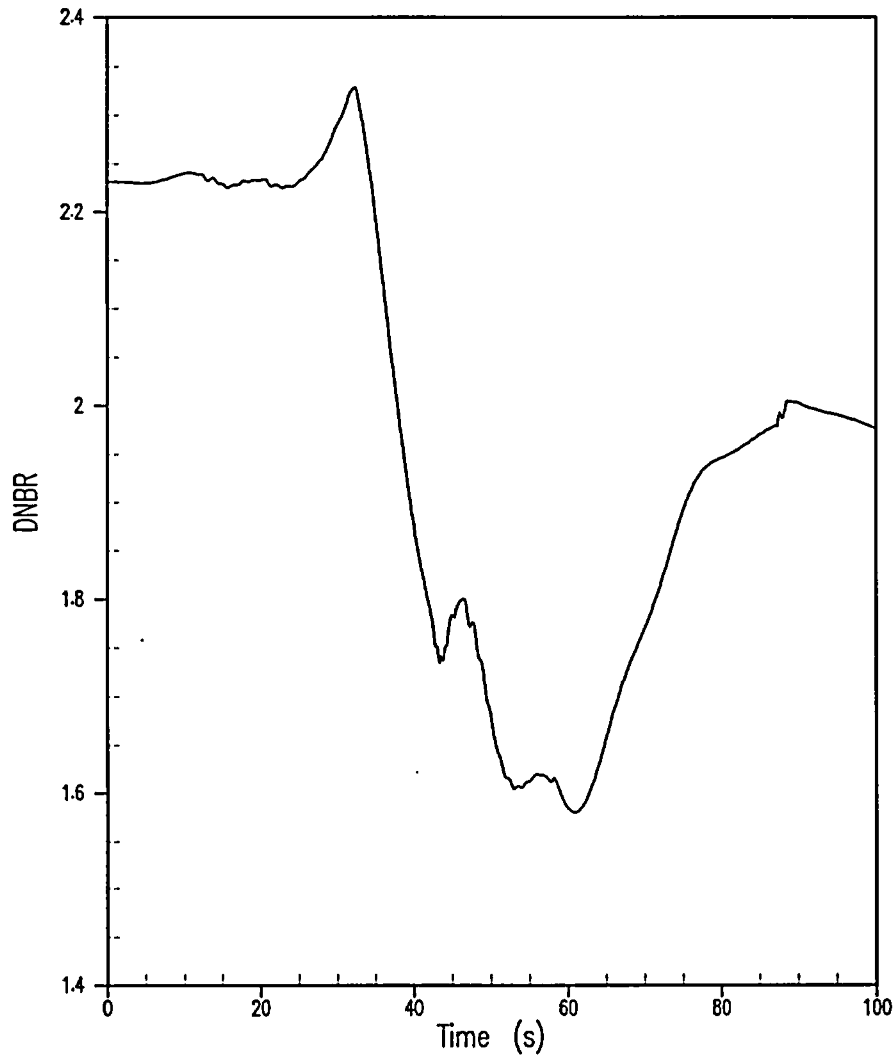


Figure 5.1.12-16 Feedwater Line Break DNB Case
Limiting Break Size = 0.25 ft^2 DNBR

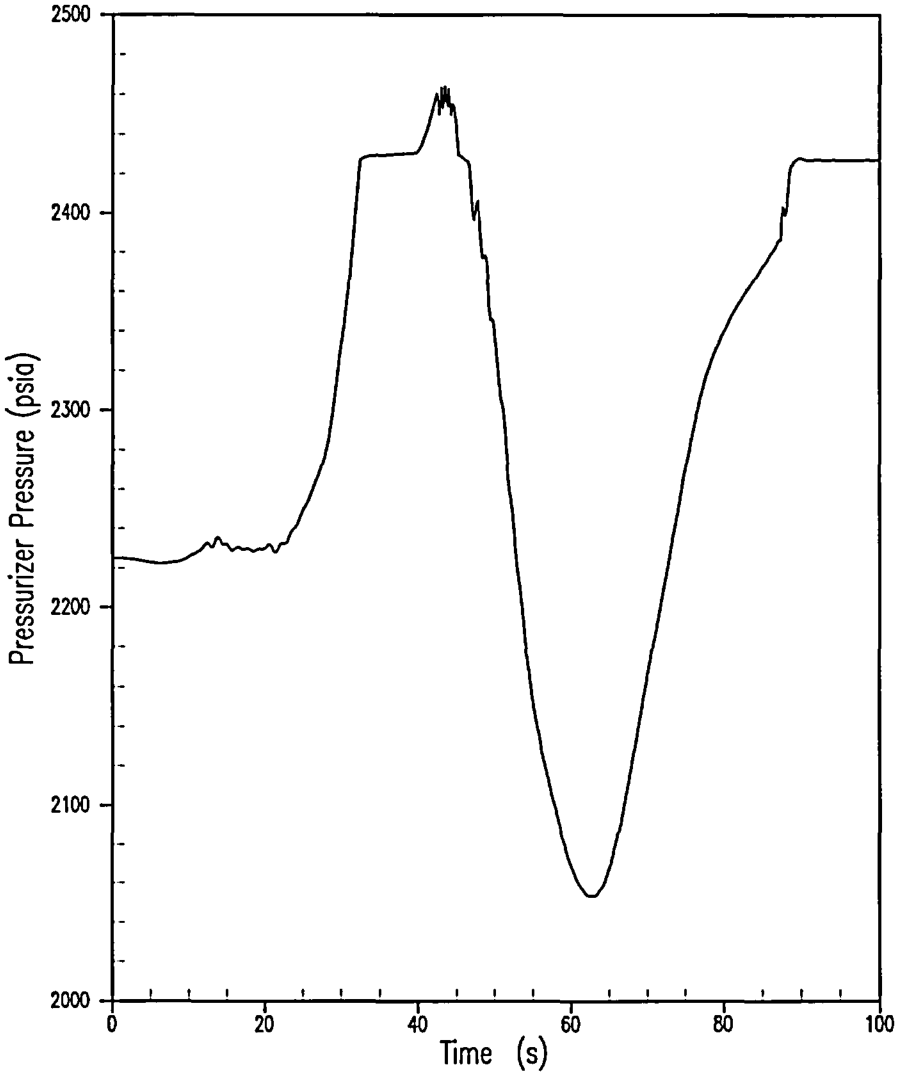


Figure 5.1.12-17 Feedwater Line Break DNB Case Limiting Break Size = 0.25 ft^2 Pressurizer Pressure

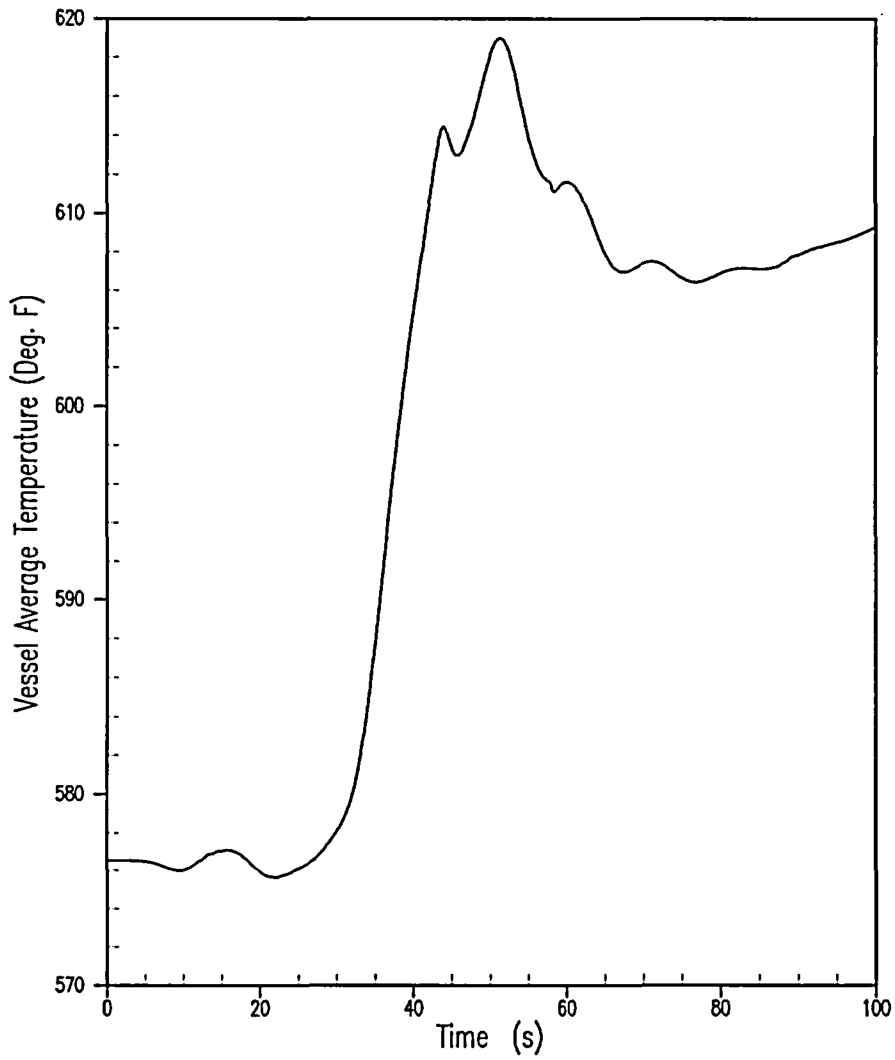


Figure 5.1.12-18 Feedwater Line Break DNB Case
Limiting Break Size = 0.25 ft^2 Vessel Average Temperature

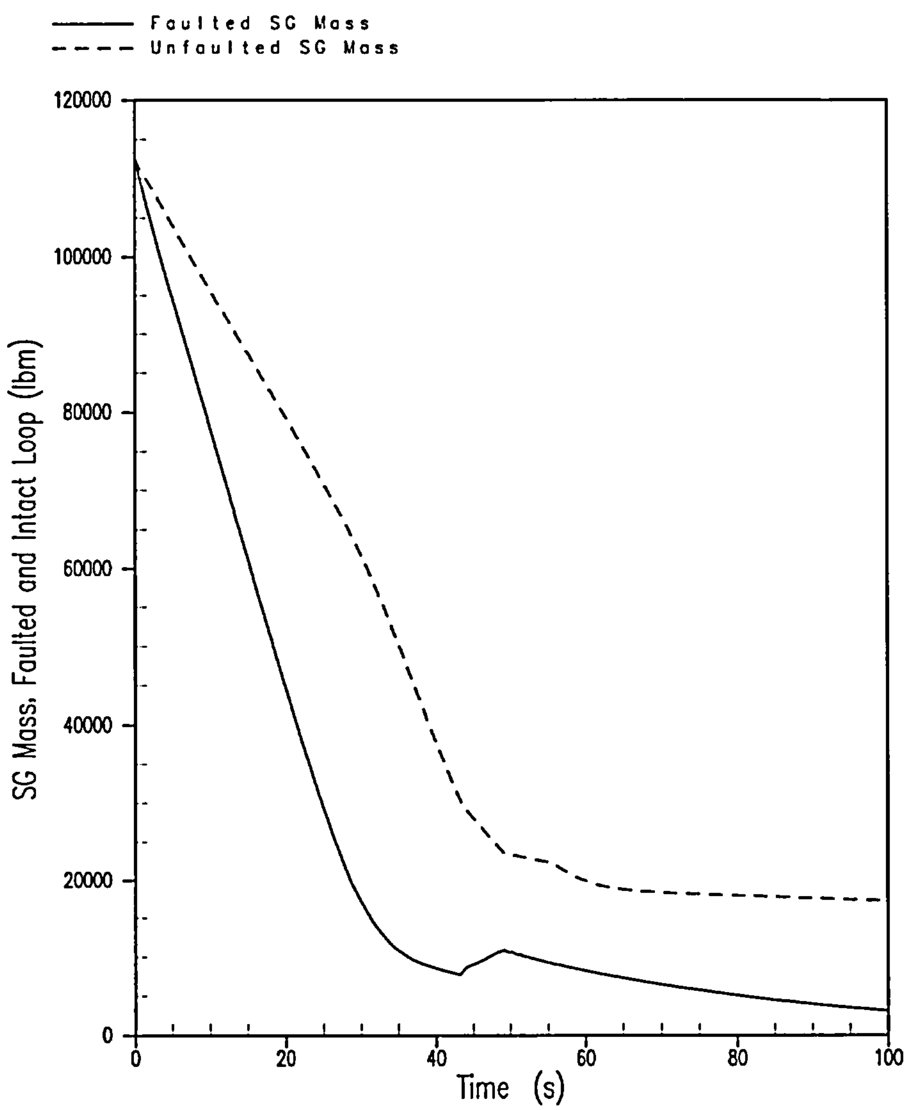


Figure 5.1.12-19 Feedwater Line Break DNB Case
Limiting Break Size = 0.25 ft^2 SG Mass, Faulted and Intact Loop

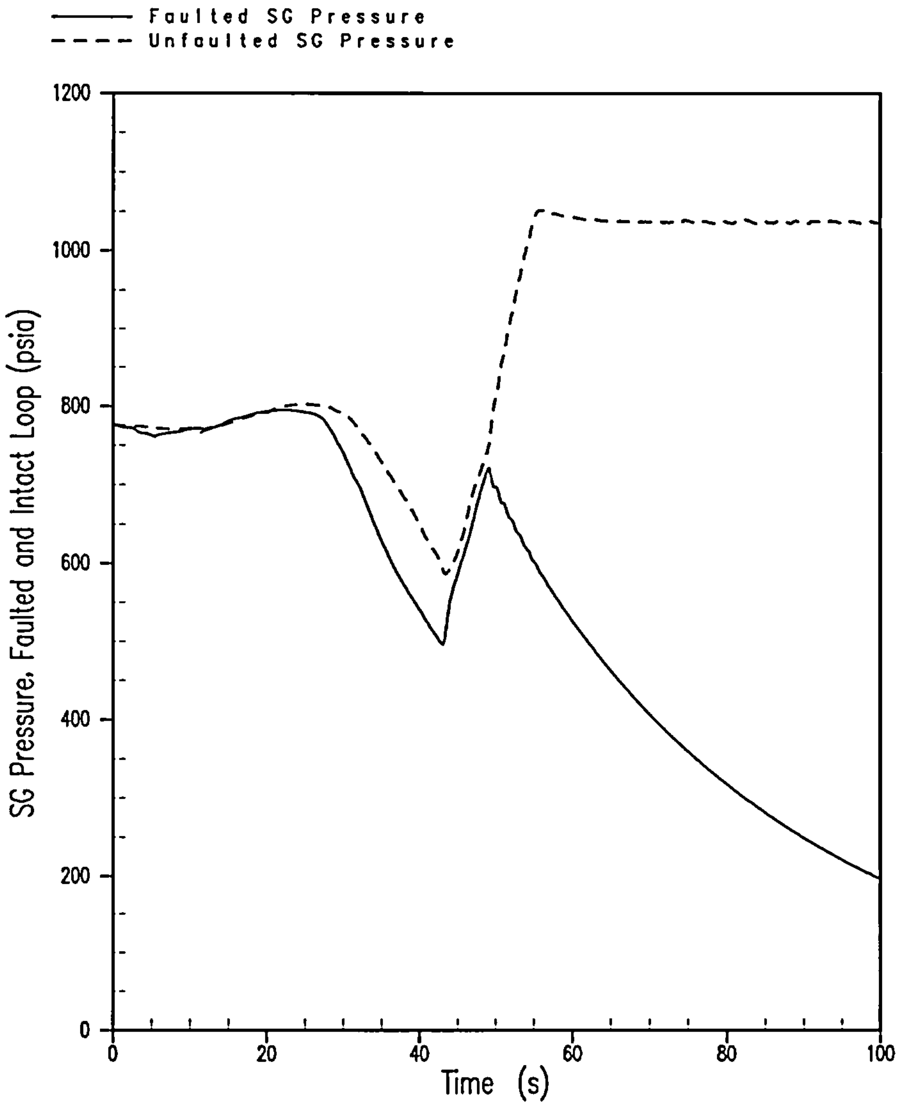


Figure 5.1.12-20 Feedwater Line Break DNB Case
Limiting Break Size = 0.25 ft² SG Pressure, Faulted and Intact Loop

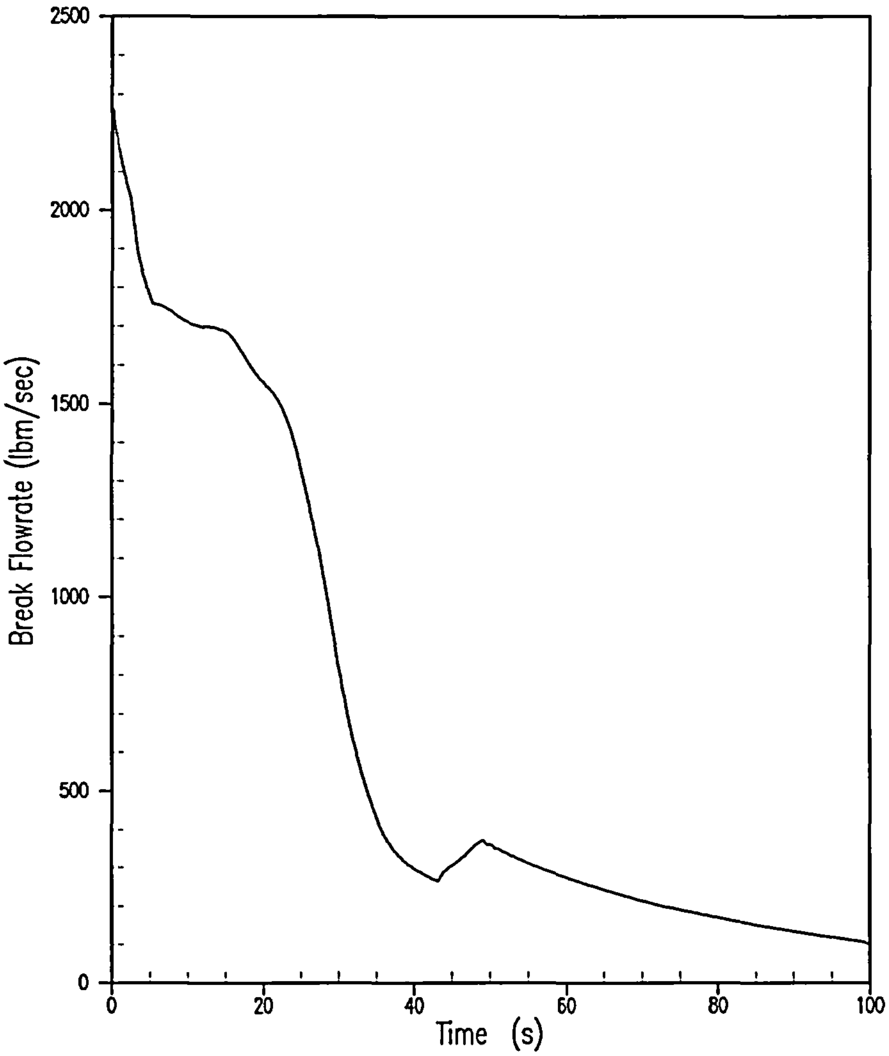


Figure 5.1.12-21 Feedwater Line Break DNB Case Limiting Break Size = 0.25 ft^2 Break Flowrate

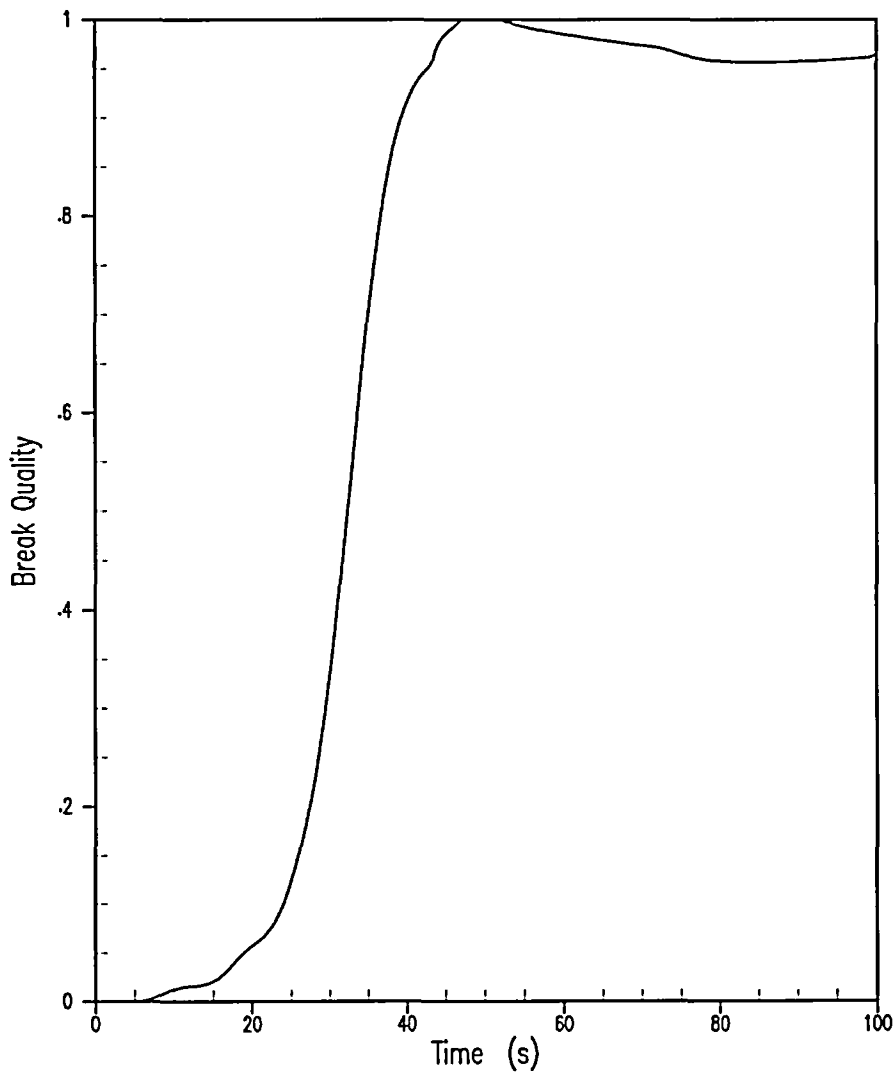


**Figure 5.1.12-22 Feedwater Line Break DNB Case
Limiting Break Size = 0.25 ft^2 Break Quality**

NRC Request 4: (Paul Clifford)

During a recent review in support of a Waterford Unit 3 Extended Power Uprate application, the NRC staff acquired a better understanding of a previously unanalyzed condition potentially related to the FWLB event. During an inside containment (IC) FWLB event, an SIAS may be generated on high-containment pressure. Since all charging pumps start on an SIAS, the potential exists that the mass addition due to the charging pumps may exacerbate the transient. The NRC staff has concerns that during an IC FWLB event, the St. Lucie Unit 2 Emergency Operating Procedures (EOPs) may not be adequate to instruct the operators to limit the charging flow. In response to RAI question 6.b, FPL cited 2-EOP-06, "which will be entered on a loss of feedwater event." Please discuss the EOP actions to mitigate the reactor coolant system (RCS) fill-up in the event that a SIAS is generated during an IC FWLB.

Response 4:

In accordance with the current licensing basis, the feedwater line break scenario analyzed in the UFSAR Section 10.4.9A would not result in lifting the pressurizer safety valves (PSVs) in conjunction with the power operated relief valves (PORVs), as the PORVs have opening setpoint lower than that of the PSVs. For a feedwater line break scenario, based on the indications available, operators would enter 2-EOP-05 (Excess Steam Demand). However, either of the procedures, 2-EOP-05 (Excess Steam Demand) and 2-EOP-06 (Total Loss of Feedwater), would require operators to maintain pressurizer level below 68%. In the event of a SIAS, pressurizer level would be controlled not to exceed 68% by controlling charging and HPSI throttling to prevent pressurizer from going solid. Pressurizer fill is thus not a concern.

NRC Request 7: (Paul Clifford)

This question is related to RAI question 5.a. In past reloads, the MSLB initiated from hot-full-power (HFP) conditions was as limiting as the case initiated at hot-zero-power (HZP) conditions. The St. Lucie Unit 2 license amendment did not include such a HFP case. At the July 2004 meeting at NRC HQ, the NRC staff requested that FPL submit the limiting HFP case so that the NRC staff would be convinced that it was no longer limiting relative to the HZP case. The NRC staff expect that the MSLB calculation will address:

a. Comparison between the UFSAR analysis of record case and the new HFP MSLB case.

b. Detailed sequence of events and input assumptions for the HFP MSLB case.

c. Comparison between cycle-specific scram worth and shutdown margin (SDM) assumed in the case.

    i. Reload Process confirmation of scram worth.

    ii. Comparison between SDM requirements assumed in analysis and St. Lucie Unit 2 operating procedures for ensuring compliance to Technical Specification SDM.

Response 7:

Historically, Westinghouse has not analyzed the full power steamline break to a post-trip condition, as it is bounded by the post-trip steamline break initiated from hot zero power conditions. As stated previously, a SLB event from hot full power to a post-trip condition is not a limiting condition due to a number of effects, including the presence of decay heat, a significantly lower inventory in the steam generators and the energy stored in the RCS thick metal mass. However, in response to this RAI, the event was analyzed to demonstrate that it is indeed non-limiting. The event was analyzed with the following assumptions.

- Full power initial condition
- No decay heat
- No metal masses other than the core and steam generator tubes
- 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

The above case was analyzed from a full power initial condition for the post-trip transient. The result was that the reactor did not return to a critical condition. Sufficient negative reactivity is inserted into the core via the drop of the CEAs to preclude a return to criticality. The tables on the following pages present the input assumptions and a detailed time sequence of events used in the UFSAR analysis of record (AOR) and those used in the analysis performed in response to the RAI. This is followed by plots for the core heat flux, core temperatures, RCS pressure, SG pressure, and reactivity. A brief discussion on differences in the UFSAR plots versus the RAI analysis plots is also provided.

Regarding the question on the scram worth and shutdown margin, the following is presented. The Westinghouse safety analyses can model either the insertion of a total minimum scram worth or the Technical Specification shutdown margin. The scram worth needed to establish the Technical Specification shutdown margin is based on:

- the reactivity needed to overcome the Doppler reactivity feedback for the fuel temperature being reduced to the no-load temperature plus
- the reactivity needed to overcome the reduction of the core coolant density from the plant initial conditions down to the RCS no-load temperatures at nominal pressure conditions.

The approach of using the negative reactivity required to just meet the shutdown margin ensures that the safety analyses support the Technical Specifications. The Westinghouse reload methodology confirms that there is sufficient negative reactivity in the rods when satisfying the Technical Specification rod insertion limits at the associated power level to overcome the Doppler reactivity effect and moderator changes in going from a full power condition to a zero power condition and to take the reactor subcritical by the Technical Specification value. This calculation assumes that the most reactive rod is stuck out of the core and is checked to ensure that there is sufficient negative reactivity to meet the shutdown margin at any time in the cycle.

This process is performed each cycle and helps ensure that the safety analyses remains bounding with respect to the shutdown margin requirement. Rod worth measurements are performed at the beginning of each cycle to ensure that the measured rod worths are within the rod worths, including uncertainties, determined in the core design calculations. This verification ensures that the core design calculations for the shutdown margin meet the Technical Specification requirements and safety analysis assumptions.

Comparison of the Current Licensing Basis Steam System Piping Failure Hot Full Power - Post-Trip Event to the Westinghouse (W) RAI Analysis

	Current License	**W RAI Response**	**Comments**
Analysis Assumptions:			
Reactor Power	2754 MWt	2700 MWt	2% power uncertainty
Tinlet	554°F	535.5°F	W assumes lower Tavg of 563.0°F
RCS Flowrate	363,000 gpm	341,400 gpm	
MTC (End of Cycle)	-32 pcm/F	More negative than -32 pcm/F	W assumes an MTC consistent with the assumption of N-1 rods in the core.
CEA Worth	-7.3 %Δρ	Worth required to meet TS SDM	W assumes sufficient trip reactivity to just meet Tech Spec SDM
Inverse Boron Worth	115 ppm/%Δρ	111 ppm/%Δρ	Safety Injection boron worth
Break Size	Full Double-Ended Rupture (6.358 ft^2)	Full Double-ended rupture (6.305 ft^2)	Slight difference due to conversion of diameter to area.
SG Pressure	949 psia	817 psia	Difference due to different initial Tavg assumed
SG Mass	156521 lbm	141013 lbm	Difference due in part to the different initial Tavg assumed
Feedwater Flow	Full Power Feedwater Flow to FWI	Full Power Feedwater Flow to FWI	
SI Flow	Minimum Flow From One Pump	Minimum Flow from one Pump	SI is initiated in both cases on low PZR pressure

Comparison to UFSAR Table 15.1.4.3-8
Sequence of Events for the Post-Trip Steam Line Break Event, Inside Containment, at Hot Full Power, Without Loss Of Offsite Power and with HPSI Pump Failure

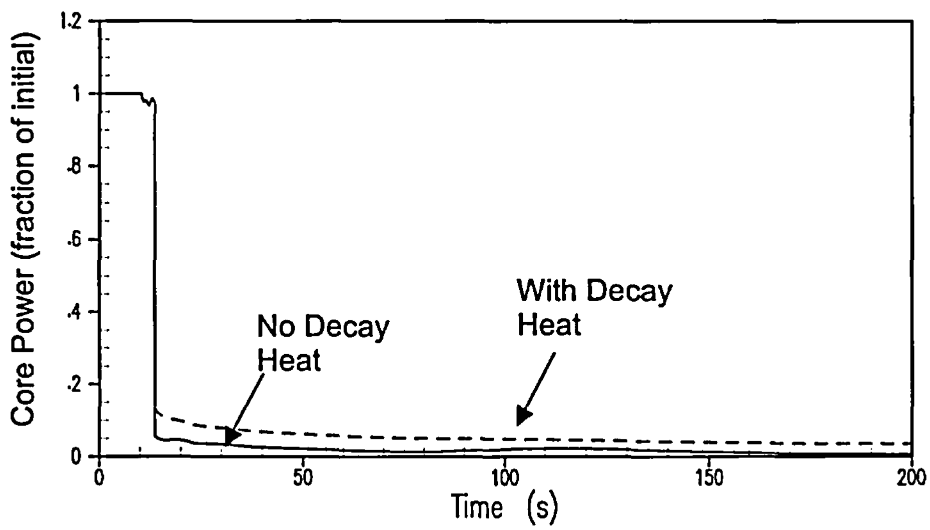
Event	UFSAR Time (Setpoint)	RAI Response Time (Setpoint)
Guillotine Break Of Main Steam Line Inside Containment	0 seconds	0 seconds
Low Steam Generator Pressure Trip Signal	3.50 seconds (540 psia)	2.49 seconds Note 1 (546 psia)
Main Steamline Isolation Signal Is Generated	3.80 seconds (520 psia)	2.78 seconds (520 psia)
Reactor Trips	4.65 seconds	3.63 seconds
Main Steam And Feedwater Isolation Valves Begin To Close	4.95 seconds	7.83 seconds Note 2
CEA's Drop Into The Core	5.45 seconds	4.63 seconds
Main Feedwater Isolation Valves Are Fully Closed (5.15 Seconds)	8.95 seconds	7.93 seconds
Main Steamline Valves Are Fully Closed (6.75 Seconds)	10.55 seconds	9.53 seconds
Steam Generator Differential Pressure Setpoint Is Reached	11.47 seconds (360 psid)	Not assumed
Pressurizer Empties	19.62 second	49.00 seconds
Safety Injection Actuation Signal Generated On Low Pressurizer Pressure	19.97 seconds (1578 psia)	31.81 seconds (1646 psia) Includes harsh environ. error
Ruptured Steam Generator Empties (<5000 Lbm)	48.91 seconds	~185 seconds Note 3
High Pressure Safety Injection Pump Reaches Full Speed	49.97 seconds	51.81 seconds
Power (At/Near Peak Post-Trip Reactivity)	51.80 seconds (10% of 2700 MWt including decay heat)	~90 seconds Note 3 (~3.4% of 2700 MWt with no decay heat) (~6.8% with maximum decay heat)
Maximum Post-Trip Reactivity	53.85 seconds (-0.6171%$\Delta\rho$)	~110 seconds (~-0.600%$\Delta\rho$)
Safety Injection, Boron Enters The Core	104.3 seconds	~100 seconds

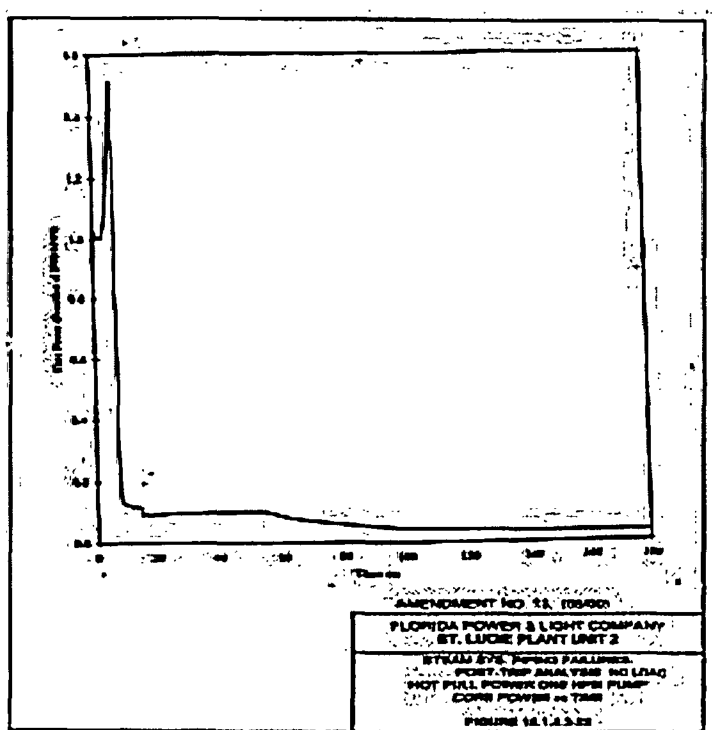
Note 1 The low steamline pressure setpoint is reached sooner in the RAI response because of the lower initial SG pressure.

Note 2 The RAI response assumes that the isolation valves remain fully open until the last 0.1 seconds where it is assumed that the valves rapidly close.

Note 3 The UFSAR analysis model of the steam generator tube bundle heat transfer artificially forces a full heat transfer coefficient till there is 5000 lbm of inventory in the steam generator. The licensing submittal/RAI responses model the heat transfer coefficients based upon the conditions in the tube bundle.

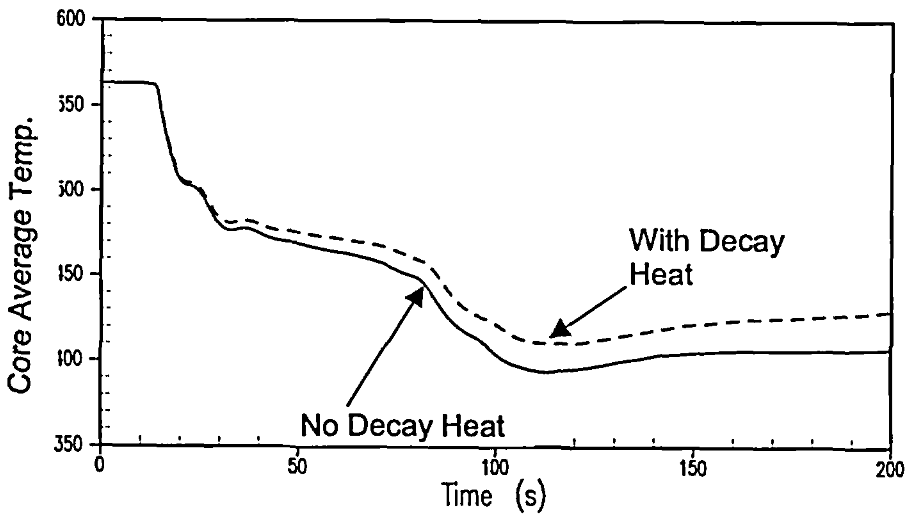
Figure RAI 7-1:
HFP SLB Results Comparison
- Core Power versus Time -
RAI Analysis (With and without Decay Heat) vs. UFSAR AOR (UFSAR Figure 15.1.4.3-23)

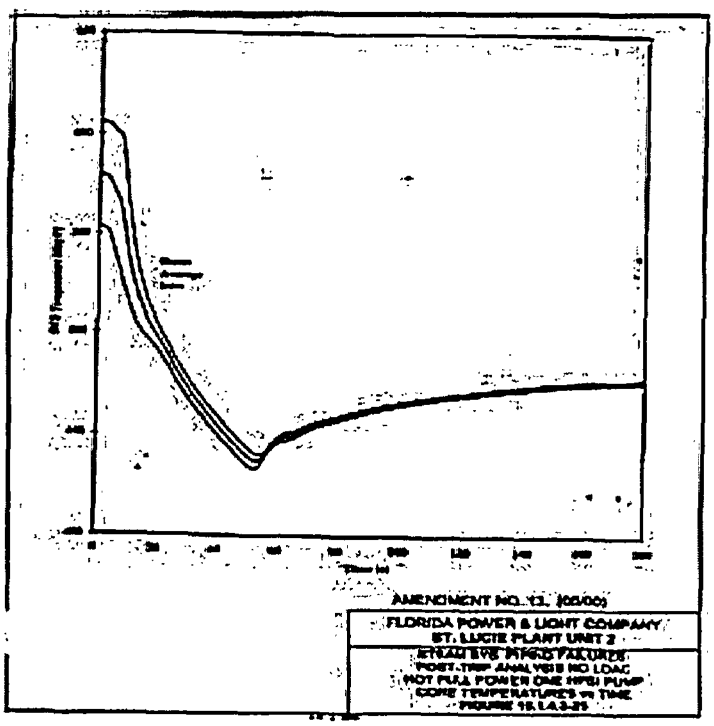




Note that in the RAI Analysis curves, there is no increase in the core power just beyond the time of event initiation, as observed in the UFSAR plot. This is due to the fact that a low steam line pressure trip is generated and the rods begin to fall into the core before the colder water from the SG can reach the core. The power increase is non-conservative, as it adds additional energy to the RCS and helps retard the eventual cooldown of the RCS following the reactor trip.

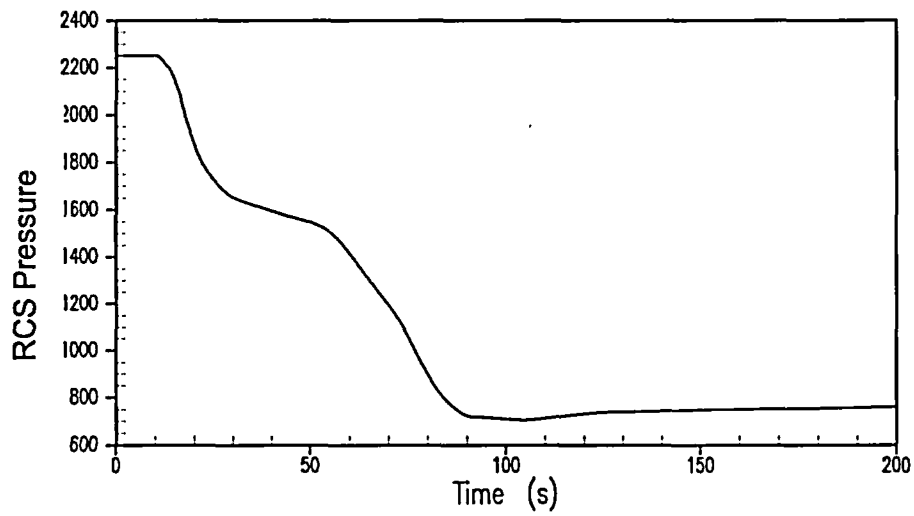
Figure RAI 7-2:
HFP SLB Results Comparison
- Core Average Temperature Versus Time -
RAI Analysis (With and Without Decay Heat) vs. UFSAR AOR (UFSAR Figure 15.1.4.3-25)

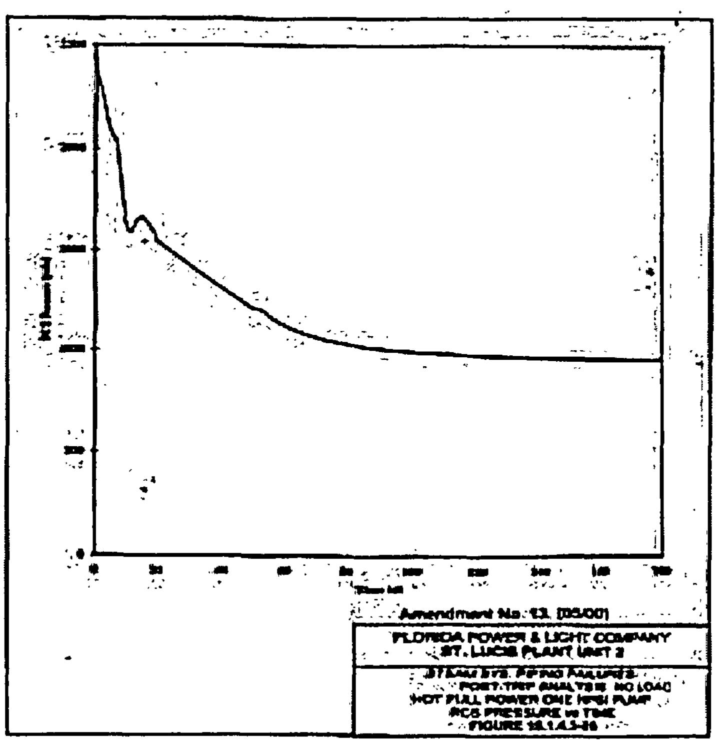




Note that the RAI analysis curves drop slower compared to the UFSAR plot. The reason for this is that the UFSAR analysis assumes full heat transfer in the steam generator until the mass reaches 5000 lbm. A heat transfer coefficient consistent with the mass in the steam generator is assumed in the RAI analysis.

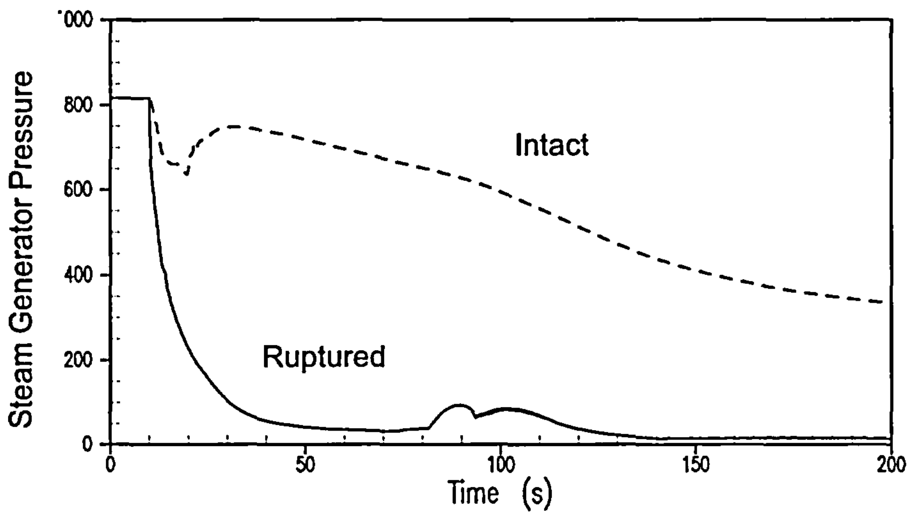
Figure RAI 7-3:
HFP SLB Results Comparison
- RCS Pressure Versus Time -
RAI Analysis vs. UFSAR AOR (UFSAR Figure 15.1.4.3-26)





Note that the RAI analysis curve drops slower compared to the UFSAR plot. The reason for this is that the UFSAR analysis assumes full heat transfer in the steam generator until the mass reaches 5000 lbm. A heat transfer coefficient consistent with the mass in the steam generator is assumed in the RAI analysis. Also note that the minimum pressure in the RAI analysis is significantly lower than that of the UFSAR analysis.

Figure RAI 7-4:
HFP SLB Results Comparison
- Steam Generator Pressure Versus Time -
RAI Analysis vs. UFSAR AOR (UFSAR Figure 15.1.4.3-27)



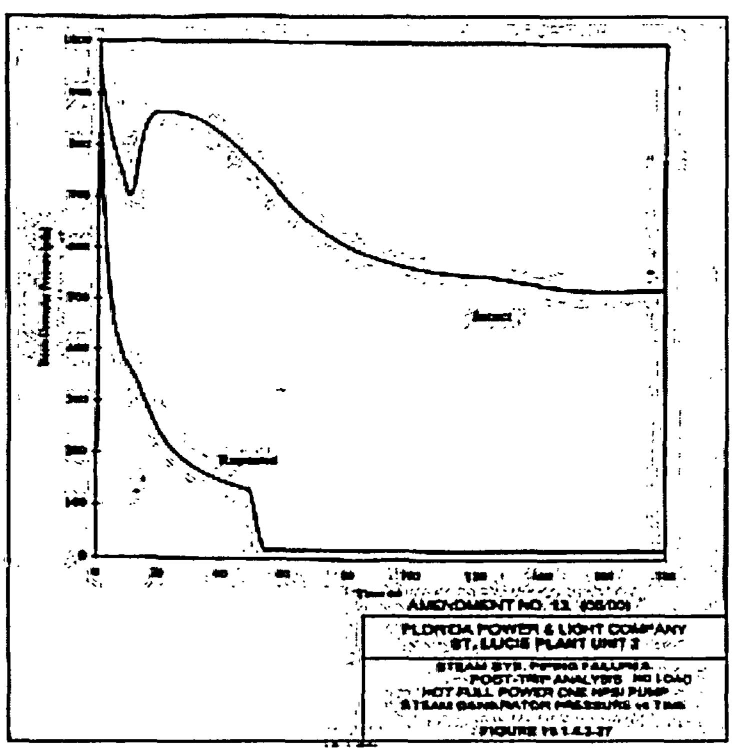
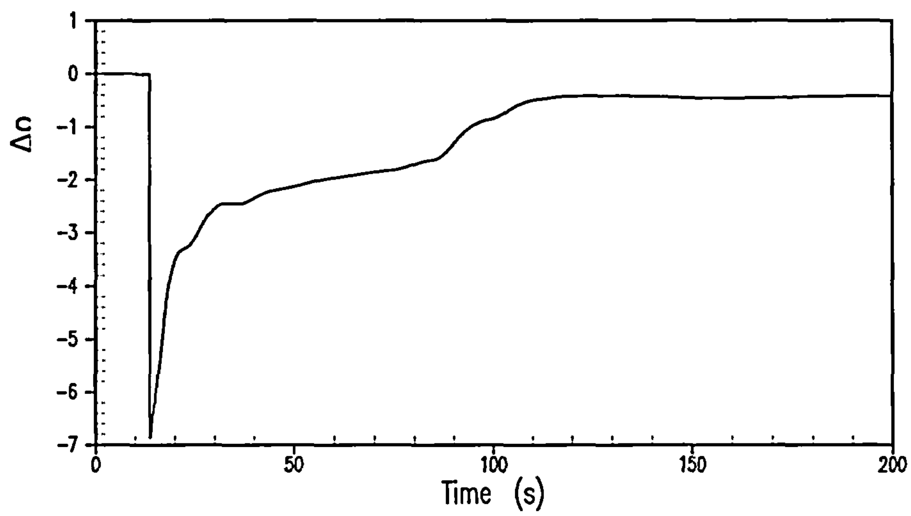
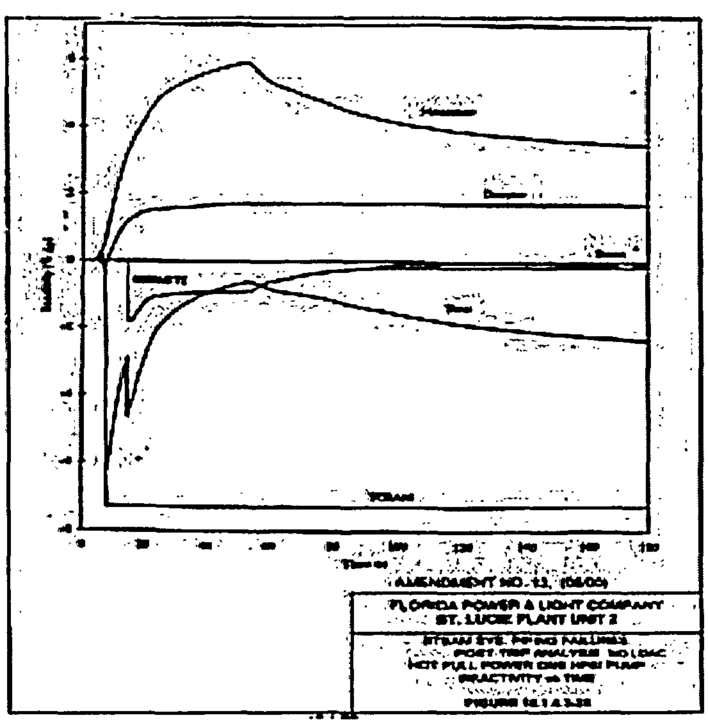


Figure RAI 7-5:
HFP SLB Results Comparison
- Reactivity Versus Time -
RAI Analysis vs. UFSAR AOR (UFSAR Figure 15.1.4.3-28)





Note that the negative reactivity added in the RAI analysis is comparable and the approach to criticality is approximately the same magnitude as the UFSAR analysis. The approach to criticality is slower due to the reasons stated previously for the RCS temperature (Figure RAI7-2) and pressure (Figure RAI7-3).

ATTACHMENT 3

ST. LUCIE UNIT 2 MARKED-UP AND RETYPED TECHNICAL SPECIFICATION PAGE FOR RCS OPERATION LEAKAGE

This page was previously submitted by FPL letter L-2003-220 dated September 18, 2003 and was requested by the NRC to be resubmitted with this supplement to the proposed license amendment as part of the selective implementation of AST.

TS Page

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St. Lucie Unit 2
Docket No. 50-389
L-2005-007 Attachment 3 Page 2

REACTOR COOLANT SYSTEM

OPERATIONAL LEAKAGE

LIMITING CONDITION FOR OPERATION

3.4.6.2 Reactor Coolant System leakage shall be limited to:

a. No PRESSURE BOUNDARY LEAKAGE,

b. 1 gpm UNIDENTIFIED LEAKAGE,

0.3 c. 1 gpm total primary-to-secondary leakage through steam generators and 720 gallons per day through any one steam generator,

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d. 10 gpm IDENTIFIED LEAKAGE from the Reactor Coolant System, and

e. 1 gpm leakage (except as noted in Table 3.4-1) at a Reactor Coolant System pressure of 2235 ± 20 psig from any Reactor Coolant System Pressure Isolation Valve specified in Table 3.4-1.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

a. With any PRESSURE BOUNDARY LEAKAGE, be in at least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With any Reactor Coolant System leakage greater than any one of the limits, excluding PRESSURE BOUNDARY LEAKAGE and leakage from Reactor Coolant System Pressure Isolation Valves, reduce the leakage rate to within limits within 4 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

c. With any Reactor Coolant System Pressure Isolation Valve leakage greater than the above limit, isolate the high pressure portion of the affected system from the low pressure portion within 4 hours by use of at least two closed manual or deactivated automatic valves, or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

d. With RCS leakage alarmed and confirmed in a flow path with no flow indication, commence an RCS water inventory balance within 1 hour to determine the leak rate.

SURVEILLANCE REQUIREMENTS

4.4.6.2.1 Reactor Coolant System leakages shall be demonstrated to be within each of the above limits by:

a. Monitoring the containment atmosphere gaseous and particulate radioactivity monitor at least once per 12 hours.

b. Monitoring the containment sump inventory and discharge at least once per 12 hours.

REACTOR COOLANT SYSTEM

OPERATIONAL LEAKAGE

LIMITING CONDITION FOR OPERATION

3.4.6.2 Reactor Coolant System leakage shall be limited to:

a. No PRESSURE BOUNDARY LEAKAGE,

b. 1 gpm UNIDENTIFIED LEAKAGE,

c. 0.3 gpm total primary-to-secondary leakage through steam generators and 216 gallons per day through any one steam generator,

d. 10 gpm IDENTIFIED LEAKAGE from the Reactor Coolant System, and

e. 1 gpm leakage (except as noted in Table 3.4-1) at a Reactor Coolant System pressure of 2235 $\pm$ 20 psig from any Reactor Coolant System Pressure Isolation Valve specified in Table 3.4-1.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

a. With any PRESSURE BOUNDARY LEAKAGE, be in at least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With any Reactor Coolant System leakage greater than any one of the limits, excluding PRESSURE BOUNDARY LEAKAGE and leakage from Reactor Coolant System Pressure Isolation Valves, reduce the leakage rate to within limits within 4 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

c. With any Reactor Coolant System Pressure Isolation Valve leakage greater than the above limit, isolate the high pressure portion of the affected system from the low pressure portion within 4 hours by use of at least two closed manual or deactivated automatic valves, or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

d. With RCS leakage alarmed and confirmed in a flow path with no flow indication, commence an RCS water inventory balance within 1 hour to determine the leak rate.

SURVEILLANCE REQUIREMENTS

4.4.6.2.1 Reactor Coolant System leakages shall be demonstrated to be within each of the above limits by:

a. Monitoring the containment atmosphere gaseous and particulate radioactivity monitor at least once per 12 hours.

b. Monitoring the containment sump inventory and discharge at least once per 12 hours.

"JOHNSON, Arika"
<amj@nei.org>
01/07/2005 02:57 PM

To: ken_frehafer@fpl.com
cc:
Subject: Confirmation of Transaction - Summary

TRANSACTION SUMMARY

Date: 01/07/2005
Account #: 48439
Mr. Kenneth W. Frehafer
Licensing Engineer
Florida Power & Light Company
6501 South Ocean Drive
Jensen Beach, FL 34957

Reference: R25501
Description: Mitigating System Performance Index Wksp 1
Amount: 375.00

Total: 375.00
Payment: 375.00
Balance: 0.00

You have been successfully registered for the above "Description" conference. This summary receipt recaps your registration fee and any additional activities. If you have any questions, call Arika Johnson at (202) 739-8039 or amj@nei.org.

Payment method: AMEX

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