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

FPL

This letter forwards proprietary information in accordance with 10 CFR 2.390. The balance of this letter may be considered non-proprietary upon removal of Attachment 1.

October 31, 2011

L-2011-448
10 CFR 50.90
10 CFR 2.390

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

Re: St. Lucie Plant Unit 1
Docket No. 50-335
Renewed Facility Operating License No. DPR-67

Response to NRC Reactor Systems Branch and Nuclear Performance Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request

References:

(1) R. L. Anderson (FPL) to U.S. Nuclear Regulatory Commission (L-2010-259), "License Amendment Request (LAR) for Extended Power Uprate," November 22, 2010, Accession No. ML103560419.

(2) NRC (Tracy Orf) email to FPL (Chris Wasik), St. Lucie 1 EPU draft RAIs – Reactor Systems (SRXB), August 23, 2011.

(3) NRC (Tracy Orf) email to FPL (Chris Wasik), St. Lucie 1 EPU draft RAIs – additional Reactor Systems (SRXB), September 6, 2011.

(4) NRC (Tracy Orf) email to FPL (Chris Wasik), St. Lucie 1 (and 2) EPU draft RAI – Nuclear Performance and Code Branch (SNPB), September 28, 2011.

(5) R.L. Anderson (FPL) to U.S. Nuclear Regulatory Commission (L-2011-389), "Response to NRC Reactor Systems Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request," September 22, 2011, Accession No. ML11269A221.

(6) R.L. Anderson (FPL) to U.S. Nuclear Regulatory Commission (L-2011-418), "Response to NRC Reactor Systems Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request," September 30, 2011.

(7) R.L. Anderson (FPL) to U.S. Nuclear Regulatory Commission (L-2011-413), "Response to NRC Reactor Systems Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request," September 29, 2011.

A001
NRR

By letter L-2010-259 dated November 22, 2010 [Reference 1], Florida Power & Light Company (FPL) requested to amend Renewed Facility Operating License No. DPR-67 and revise the St. Lucie Unit 1 Technical Specifications (TS). The proposed amendment will increase the unit's licensed core thermal power level from 2700 megawatts thermal (MWt) to 3020 MWt and revise the Renewed Facility Operating License and TS to support operation at this increased core thermal power level. This represents an approximate increase of 11.85% and is therefore considered an Extended Power Uprate (EPU).

By emails from the NRC Project Manager dated August 23, 2011 [Reference 2], September 6, 2011 [Reference 3], and September 28, 2011 [Reference 4], additional information related to reactor systems and nuclear performance was requested by the NRC staff in the Reactor Systems Branch (SRXB) and Nuclear Performance and Code Branch (SNPB) to support their review of the EPU LAR. Reference 2 contains thirty-two (32) RAIs, numbered SRXB-15 through SRXB-46. Reference 3 contains five (5) RAIs numbered SRXB-47 through SRXB-51 and Reference 4 contains one (1) RAI numbered SNPB-16. With respect to Reference 3, the response to SRXB-47 is the only RAI response to be included as part of this correspondence.

The RAI responses presented in Attachment 1 were prepared by Areva and contain information proprietary to Areva. Attachment 3 provides the Areva affidavit which requests withholding of Attachment 1 information from public disclosure. The Affidavit, signed by Areva as the owner of the information, sets forth the basis for which the information may be withheld from public disclosure by the Commission and addresses with specificity the considerations listed in paragraph (b)(4) of § 2.390 of the Commission's regulations. Accordingly, it is respectfully requested that the information which is proprietary to Areva be withheld from public disclosure in accordance with 10 CFR 2.390.

Attachment 2 presents responses to SRXB and SNPB RAIs that are considered non-proprietary.

Note that FPL previously provided responses to SRXB-36, 37, 41, 48 through 51, and 46 via References 5, 6 and 7.

In accordance with 10 CFR 50.91(b)(1), a copy of this letter is being forwarded to the designated State of Florida official.

This submittal does not alter the significant hazards consideration or environmental assessment previously submitted by FPL letter L-2010-259 [Reference 1].

This submittal contains no new commitments and no revisions to existing commitments.

Should you have any questions regarding this submittal, please contact Mr. Christopher Wasik, St. Lucie Extended Power Uprate License Amendment Request (LAR) Project Manager, at 772-467-7138.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge.

Executed on 31-October-2011

Very truly yours,

Richard L. Anderson
Site Vice President
St. Lucie Plant

Attachments (3)

cc: Mr. William Passetti, Florida Department of Health

ATTACHMENT 3

Response to NRC Reactor Systems Branch and Nuclear Performance and Code Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request

AREVA
Application for Withholding Proprietary Information from Public Disclosure

(Cover page plus 3 pages)

AFFIDAVIT

STATE OF WASHINGTON)
) ss.
COUNTY OF BENTON)

1. My name is Alan B. Meginnis. I am Manager, Product Licensing, for AREVA NP Inc. and as such I am authorized to execute this Affidavit.

2. I am familiar with the criteria applied by AREVA NP to determine whether certain AREVA NP information is proprietary. I am familiar with the policies established by AREVA NP to ensure the proper application of these criteria.

3. I am familiar with the AREVA NP information contained in the report ANP-3039(P) Revision 0, entitled, "St. Lucie Unit 1 EPU – Responses to NRC SRXB Questions," dated October 2011 and referred to herein as "Document." Information contained in this Document has been classified by AREVA NP as proprietary in accordance with the policies established by AREVA NP for the control and protection of proprietary and confidential information.

4. This Document contains information of a proprietary and confidential nature and is of the type customarily held in confidence by AREVA NP and not made available to the public. Based on my experience, I am aware that other companies regard information of the kind contained in this Document as proprietary and confidential.

5. This Document has been made available to the U.S. Nuclear Regulatory Commission in confidence with the request that the information contained in this Document be withheld from public disclosure. The request for withholding of proprietary information is made in accordance with 10 CFR 2.390. The information for which withholding from disclosure is

requested qualifies under 10 CFR 2.390(a)(4) "Trade secrets and commercial or financial information."

6. The following criteria are customarily applied by AREVA NP to determine whether information should be classified as proprietary:

(a) The information reveals details of AREVA NP's research and development plans and programs or their results.

(b) Use of the information by a competitor would permit the competitor to significantly reduce its expenditures, in time or resources, to design, produce, or market a similar product or service.

(c) The information includes test data or analytical techniques concerning a process, methodology, or component, the application of which results in a competitive advantage for AREVA NP.

(d) The information reveals certain distinguishing aspects of a process, methodology, or component, the exclusive use of which provides a competitive advantage for AREVA NP in product optimization or marketability.

(e) The information is vital to a competitive advantage held by AREVA NP, would be helpful to competitors to AREVA NP, and would likely cause substantial harm to the competitive position of AREVA NP.

The information in the Document is considered proprietary for the reasons set forth in paragraphs 6(b), 6(d) and 6(e) above.

7. In accordance with AREVA NP's policies governing the protection and control of information, proprietary information contained in this Document have been made available, on a limited basis, to others outside AREVA NP only as required and under suitable agreement providing for nondisclosure and limited use of the information.

8. AREVA NP policy requires that proprietary information be kept in a secured file or area and distributed on a need-to-know basis.

9. The foregoing statements are true and correct to the best of my knowledge, information, and belief.

SUBSCRIBED before me this 4th day of October, 2011.

Susan K. McCoy
NOTARY PUBLIC, STATE OF WASHINGTON
MY COMMISSION EXPIRES: 1/10/12

SUSAN K. MCCOY
COMMISSION EXPIRES
NOTARY
PUBLIC
01-10-12
STATE OF WASHINGTON

ATTACHMENT 2

Response to NRC Reactor Systems Branch and Nuclear Performance and Code Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request

NON-PROPRIETARY RESPONSES

Responses to the following RAIs are included in this attachment:

SRXB-28
SRXB-29
SRXB-33
SRXB-34
SRXB-40
SRXB-42 through 45
SRXB-47
SNPB-16

(Cover page plus 50 pages)

Response to Request for Additional Information

The following information is provided by Florida Power & Light (FPL) in response to the U. S. Nuclear Regulatory Commission's (NRC) Request for Additional Information (RAI). This information was requested to support Extended Power Uprate (EPU) License Amendment Request (LAR) for St. Lucie Nuclear Plant Unit 1, that was submitted to the NRC by FPL via letter (L-2010-259) dated November 22, 2010, Accession Number ML103560419.

Emails dated August 23, 2011, from NRC (Tracy Orf) to FPL (Chris Wasik), Subject: St. Lucie 1 EPU draft RAIs – Reactor Systems (SRXB); September 6, 2011, from NRC (Tracy Orf) to FPL (Chris Wasik), Subject: St. Lucie 1 EPU draft RAIs – additional Reactor Systems (SRXB), and September 28, 2011, from NRC (Tracy Orf) to FPL (Chris Wasik), Subject: St. Lucie 1 (and 2) EPU draft RAI – Nuclear Performance and Code Branch; present NRC draft information requests regarding the PSL1 EPU LAR, specifically requesting additional information with respect to reactor systems and nuclear performance. The August 23, 2011, email contains 32 RAIs, numbered SRXB-15 through SRXB-46. The September 6, 2011, email contains 5 RAIs numbered SRXB-47 through SRXB-51 and the September 28, 2011, email contains 1 RAI numbered SNPB-16. With respect to the September 6, 2011 email, the response to SRXB 47 is the only RAI response, to be addressed as part of this correspondence. In addition to the above it is noted that SRXB-36 and 37, 41 and 48 through 51, and 46 have been addressed in FPL letters L-2011-389 dated September 22, 2011 (ML11269A221), L-2011-418, dated September 30, 2011, and L-2011-413, dated September 29, 2011. Response to SRXB RAI's 28, 29, 33, 34, 40, 42 through 45, 47 and SNPB-16 are presented below.

SRXB-28

The minor SLB is defined as an SLB which results in steam blowdown rates equivalent to a 6-inch break outside the containment.

1. **Why is the 6-inch break size used to define the minor SLB?**

2. **Why are the minor SLBs defined to occur outside the containment?**

3. **The minor SLB is bounded by the MSLB with respect to fuel failure. Explain how the comparison is made, between Condition III and Condition IV events, and how the extent of fuel failure is used to bound one event with the other.**

Response

The 6-inch break outside the containment is defined for minor steam line break (SLB) consistent with the current UFSAR definition as stated in UFSAR Section 15.3.2.

The analysis of SLB, as presented in EPU LAR Attachment 5, Licensing Report (LR) Section 2.8.5.1.2, covers all break sizes inside and outside of the containment. The pre-trip SLB event is analyzed for a spectrum of break sizes to ensure that adequate protection is provided by the Reactor Protection System (RPS) for all break sizes such that the fuel failures due to the initial power excursion are limited to within those used in the dose consequences analyses presented in EPU LAR Attachment 5, LR Section 2.9.2, which show acceptable results.

The post-trip SLB event analysis is dominated by the cooldown rate and the subsequent loss of shutdown margin and return-to-power. This is worse for large breaks. The analysis of this event for outside and inside containment using maximum break size is performed by maximizing the cooldown rate using conservative auxiliary feedwater (AFW) flow, taking no credit for the Technical Specifications (TS) required automatic isolation of AFW on Steam Generator (SG) pressure differential. The fuel failures are limited to within those used in the dose consequence analyses presented in EPU LAR Attachment 5, LR Section 2.9.2 (Table 2.9.2-1). The analysis of this large SLB bounds the smaller breaks which would have slower RCS cooldown, slower erosion of shutdown margin and less core inlet asymmetry. The actuation of safety systems would however come at the same RCS conditions and the slower cooldown rate would result in lower return to power, if any, than that for large breaks.

Although the current licensing basis does not explicitly classify SLB break sizes, the extent of fuel failures and the dose consequences for SLB events presented in EPU LAR Attachment 5 LR Section 2.9.2 meet the requirements for both the Condition III and Condition IV events. Thus, all break sizes are covered in the SLB analyses presented in the licensing report.

SRXB-29

[2.8.5.2.4.a] The LR states that, "in the St. Lucie Unit 1 licensing basis, the feedwater line break (FWLB) event is defined as a cooldown event that is bounded by the main steam line break (MSLB) event. The key system, subsequent to reactor trip, for mitigating the post-scram MSLB event is the Safety Injection System, which injects boron into the RCS to arrest the post-scram return-to-power (See LR Section 2.8.5.1.2). The same mitigating systems apply to both MSLB and FWLB."

Defining the FWLB as a cooldown event eliminates the FWLB from consideration as a Condition IV design basis accident (DBA). When analyzed as a heatup event, the FWLB tests fuel and RCPB integrity, and helps set the performance requirements for the AFWS. The Safety Injection System, particularly its reactivity control function, does not mitigate the FWLB, when considered as a heatup event.

The FWLB is a limiting fault, in the "decrease in heat removal by the secondary system" category in Table 15-1 of RG 1.70. It is necessary to identify the FWLB as a limiting fault in the heatup category, and provide analyses of the worst cases in the current licensing basis, and in the LR that supports the proposed EPU.

According to the specific review criteria in SRP Section 15.2.8, and the guidance in Matrix 8 of RS-001, FWLBs are to be analyzed as heatup event. As such, FWLBs are in the class of events that are directly affected by an increase in authorized power level. The LR conclusion, that the plant will continue to meet the requirements of GDC 27 and GDC 35, following implementation of the proposed EPU, is not supported by analysis.

Provide an analysis of the FWLB, considered as a heatup event, according to the specific review criteria in SRP Section 15.2.8 and the guidance in Matrix 8 of RS-001.

Response

Feedline break event analysis typically results in an initial reactor coolant system (RCS) heatup and pressure increase followed by a reactor trip and substantial RCS cooldown resulting from the boil off of steam generator (SG) inventory. RCS heatup, subsequent to this excessive RCS cooldown, remains strongly dependent on the availability of auxiliary feedwater flow, which could challenge the loss of RCS subcooling criterion.

There are several reactor trips available to restrict the initial pressure rise, which comes prior to auxiliary feedwater system (AFW) actuation and is strongly dependent on the reactor protection system setpoints, main steam safety valves (MSSV) setpoints and pressurizer safety valves (PSV) setpoints. St. Lucie Unit 1 does not have this event in the current licensing basis. This pressure rise is however analyzed for St. Lucie Unit 2 as part of Chapter 15 analyses and the RCS pressure is shown to remain within the acceptance criterion. From the St. Lucie Unit 2 conclusion, it is judged that this is not a safety issue for St. Lucie Unit 1, since the RCS conditions and mitigating functions such as the reactor trips, MSSV characteristics and PSV characteristics are similar between the two Units.

The RCS heat up, subsequent to the reactor trip, is analyzed for St. Lucie Unit 1 in the current licensing basis, as documented in the UFSAR Chapter 10 as part of the AFW system evaluation. The current licensing basis, as documented in the UFSAR, considered various events, including the feedline break, to determine the limiting events from AFW considerations. The events identified as most limiting from AFW system were the AFW high energy line break with two different single failures. This conclusion is not impacted by the EPU as the power increase will have similar impact on these events.

The limiting events for St. Lucie Unit 1 in the current licensing basis are:

1. High energy line break at turbine pump discharge concurrent with single active failure, and

2. High energy line break at "B" pump discharge concurrent with single active failure.

The first event has AFW available from 1 motor driven AFW pump, whereas the second event has no AFW for 10 minutes when operator action initiates AFW flow to "A" SG from the turbine pump.

<u>Comparison of Limiting Events to Feedline Break Event</u>:

The analyses of the above limiting events, which have main feed isolation at event initiation along with a high energy line break, bound the consequences of the feedline break event from RCS heatup and loss of RCS subcooling considerations. The feedline break event also has one motor driven AFW pump providing flow to one SG, but due to higher SG mass in the intact SG at the time of the reactor trip (main feed to intact SG is not isolated at event initiation), it has significant initial RCS cooldown from SG inventory boil off, and the RCS heatup starts from a much cooler temperature for the feedline break.

Provided next are the limiting high energy line break AFW system evaluation analyses performed for St. Lucie Unit 1 at EPU conditions.

Limiting AFW System Evaluation Analyses

Description of Analyses

Detailed analyses were performed using the S-RELAP5 code for the events with a high energy line (auxiliary feedwater line) break concurrent with a limiting single failure and no main feedwater. The limiting auxiliary feedwater (AFW) line break may occur in one of two possible locations:

- Single Motor-Driven AFW Pump – One potential break location is at the discharge of the turbine-driven AFW pump. The limiting single failure is one motor driven pump. In this case, only a single motor-driven AFW pump is available to furnish feedwater to one steam generator.

- No Motor-Driven AFW Pumps – The second potential auxiliary feedwater line break location is at the discharge of "B" motor-driven AFW pump. The limiting single failure is failure of "A" bus, assuming that "A" bus is initially aligned to "AB" bus. In this case, the operators must initiate flow from the turbine-driven AFW pump, by transferring electrical loads from dead "A" bus to energized "B" bus, before the Reactor Coolant System (RCS) loses subcooling and the pressurizer becomes liquid solid. This transfer, as presented in the Updated Final Safety Analysis Report (UFSAR), can be achieved in less than 10 minutes.

Input Parameters and Assumptions

The input parameters and biasing for the analysis of this event is shown in Table1.

- Initial Conditions – This event is analyzed from Hot Full Power (HFP) which produces the most significant challenge to the heat removal capability of the steam generators.

- Reactor Protection System Trips and Delays – This event is primarily protected by the low steam generator level trip. The reactor protection system trip setpoints and response times were conservatively biased to delay the actuation of the trip function. In addition, a maximum Control Element Assembly (CEA) holding coil delay was assumed.

- Auxiliary Feedwater – For the analysis of one motor-driven AFW pump, a minimum AFW flow rate of 296 gpm was assumed.

- Steam Generator Blowdown – A sustained steam generator blowdown rate of 50 gpm per steam generator was assumed until operators isolate the system at 20 minutes.

- Steam Dump and Bypass System – To maximize the mass loss in the steam generators, the steam dump and bypass system was assumed to be operable. The analyses support a steam dump and bypass capacity of up to 7.7 Mlbm/hr, which includes 10% conservatism. No credit was taken for an increase in AFW flow with a lower steam generator pressure.

- Reactor Coolant Pump (RCP) Operation – To maximize reactor coolant pump heat, it was assumed that offsite power was available and that the RCPs continued to run with a nominal heat input of 14.6 MWt. One pump in each loop was assumed to be tripped by the operator at 30 minutes.

Acceptance Criteria

This event was analyzed against the following acceptance criteria:

- The pressures in the reactor coolant and main steam systems should be less than 110% of design values.
- The fuel cladding integrity should be maintained by ensuring that the specified acceptable fuel design limits (SAFDLs) are not exceeded.
- An incident of moderate frequency should not generate a more serious plant condition without other faults occurring independently (some plants may challenge pressurizer overfill which could result in loss of pressure control).

The pressure acceptance criterion requires that the pressures in the reactor coolant and steam systems must be maintained below 110% of their respective system design pressures. The challenges to peak primary and secondary overpressure are less for this event (with reactor scram and nearly coincident secondary-system isolation) than for the Loss of External Load event (with early termination of secondary-system steam flow in conjunction with continued operation at power until reactor trip), St. Lucie Unit 1 EPU LAR Attachment 5, LR Section 2.8.5.2.1, Loss of External Electrical Load, Turbine Trip, and Loss of Condenser Vacuum. Thus, the primary system pressure limit is satisfied for this event as long as the pressurizer does not become liquid-filled and the pressurizer retains a steam "bubble" for pressure control. In addition, the peak secondary system pressure is bounded by the peak secondary system pressure in the Loss of External Load event. Thus, the secondary system overpressure limit is satisfied for this event since the limit was demonstrated to be satisfied in the Loss of External Load event.

The departure from nucleate boiling (DNB) acceptance criterion requires that the minimum departure from nucleate boiling ratio (MDNBR) is not less than the 95/95 correlation limit. The DNB SAFDL is not challenged during the short-term-heatup phase of the event because the reactor coolant conditions at reactor scram are close to the initial steady-state values. The DNB SAFDL is not challenged during the long-term-heatup phase of the event provided that RCS subcooling is sufficient for decay heat removal. Thus, the DNB SAFDL is satisfied for this event if RCS subcooling margin is sufficient for decay heat removal.

The fuel-melt acceptance criterion requires that none of the fuel rods in the core experience fuel centerline melt. The fuel-melt SAFDL is not challenged during the short-term-heatup phases of this event because the reactor power level and peaking at scram are close to the initial steady-state values. The fuel-melt SAFDL is not challenged during the long-term-heatup phase of the event provided that RCS subcooling is sufficient for decay heat removal. Thus, the fuel-melt SAFDL is satisfied for this event if RCS subcooling margin is sufficient for decay heat removal.

The plant condition acceptance criterion requires that the event must not generate a more serious plant condition without other faults occurring independently. In order for this criterion to be satisfied, the pressurizer must not become so full that liquid is expelled through the power operated relief valves (PORVs) and/or pressurizer safety valves (PSVs). Thus, the plant condition restriction is satisfied for this event if the pressurizer level remains below the PORV inlet piping penetrations.

Results

- Single Motor-Driven AFW Pump

The results of this analysis are summarized in Table 3. The transient sequence of events is shown in Table 2, and the transient results are shown in Figure 1 to Figure 8. The results demonstrated that the degraded AFW system capacity and actuation setpoint are adequate to maintain primary-to-secondary heat transfer such that the plant can be stabilized and brought to a safe shutdown in a controlled manner. Adequate cooling was maintained through the vaporization of the AFW and the pressurizer steam space was preserved. There was no significant heatup of the primary system. Thus, all acceptance criteria are satisfied for this event.

- No Motor-Driven AFW Pumps

The results of this analysis are summarized in Table 3. The transient sequence of events is shown in Table 2, and the transient results are shown in Figure 9 to Figure 16. With no automatic initiation of AFW flow, there is ample time (more than 10 minutes after event initiation) for the operators to start the turbine-driven AFW pump prior to losing subcooling margin and filling the pressurizer.

Table 1: High Energy Line Break: Initial Conditions and Biasing

Parameter	Value
Core Power	3,020 MWt + 0.3%
Core Inlet Temperature	551°F
RCS Flow Rate	410,922 gpm
RCP heat	14.6 MWt
Pressurizer Pressure	2,250 psia
Pressurizer Level	65.6%
Scram Reactivity	Minimum HFP
Moderator Temperature Coefficient	+2 pcm/°F
Doppler Reactivity Coefficient	-0.8 pcm/°F
Pressurizer PORV	Available
Pressurizer Spray	Available
Pressurizer Heaters	Available
Steam Bypass Control System (SBCS)	Available
Low SG Level Reactor Protection System (RPS) Trip	Nominal – uncertainty 15.5% (20.5% - 5%)
Low SG Level Engineered Safety Feature (ESF) Trip (AFW)	Nominal – uncertainty 14% (19% - 5%)
AFW Flow Rate (minimum)	296 gpm per motor-driven pump
AFW Temperature	104°F
SBCS Capacity (maximum)	1.1 * 7 Mlbm/hr = 7.7 Mlbm/hr
Steam Generator Blowdown Flow	50 gpm per SG
SG Tube Plugging	0%

Table 2: High Energy Line Break: Sequence of Events

Case	Event	Time (sec.)
Single Motor-Driven AFW Pump	Total loss of main feedwater	0.0
	Low steam generator (SG) level trip setpoint reached	14.2
	AFW actuated on low steam generator level	14.6
	Reactor scram on low SG level (including trip response delay)	15.1
	CEA insertion begins	15.6
	Steam dump and turbine bypass began to cycle	16.0
	CEAs fully inserted	18.5
	Auxiliary feedwater flow delivered to SG-2	345
	SG-1 loses inventory	683
	MSIVs closed	915
	Minimum liquid mass in SG-2 reached	1,200
	Bank 1 Main Steam Safety Valves (MSSVs) on SG-2 began to cycle	1,216
	Maximum T_{hot} reached	3,975
	Maximum pressurizer level reached	4,470
	Liquid mass began to increase in SG-2	10,050
No Motor-Driven AFW Pumps	Total loss of main feedwater	0.0
	Low steam generator level trip setpoint reached	14.2
	Reactor scram on low SG level (including trip response delay)	15.1
	CEA insertion begins	15.6
	Steam dump and turbine bypass began to cycle	16.0
	Maximum T_{hot} reached	18.0
	Maximum pressurizer level reached	18.0
	CEAs fully inserted	18.5
	Operator initiated turbine-driven AFW pump	600

Table 3: High Energy Line Break: Analysis Results

Event	Result Parameter	Analysis Limit	Analysis Result
High Energy Line Break			
• No Motor-Driven AFW Pumps	Max. pressurizer liquid volume	Less than volume of pressurizer	Less than volume of pressurizer
	Min. RCS subcooling, °F	≥ 0	47.6
• Single Motor-Driven AFW Pump	Max. pressurizer liquid volume	Less than volume of pressurizer	Less than volume of pressurizer
	Min. RCS subcooling, °F	≥ 0	47

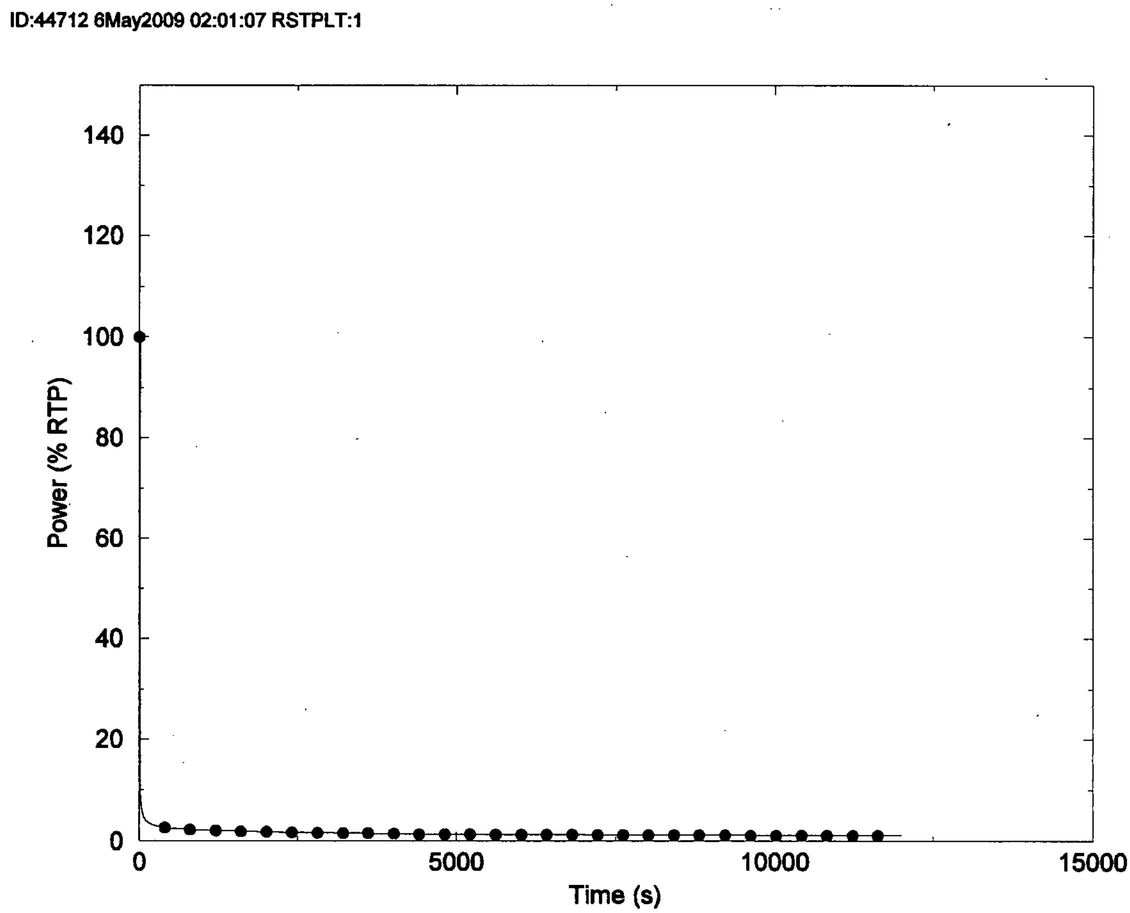

Figure 1: High Energy Line Break (Single Motor-Driven AFW Pump): Reactor Power

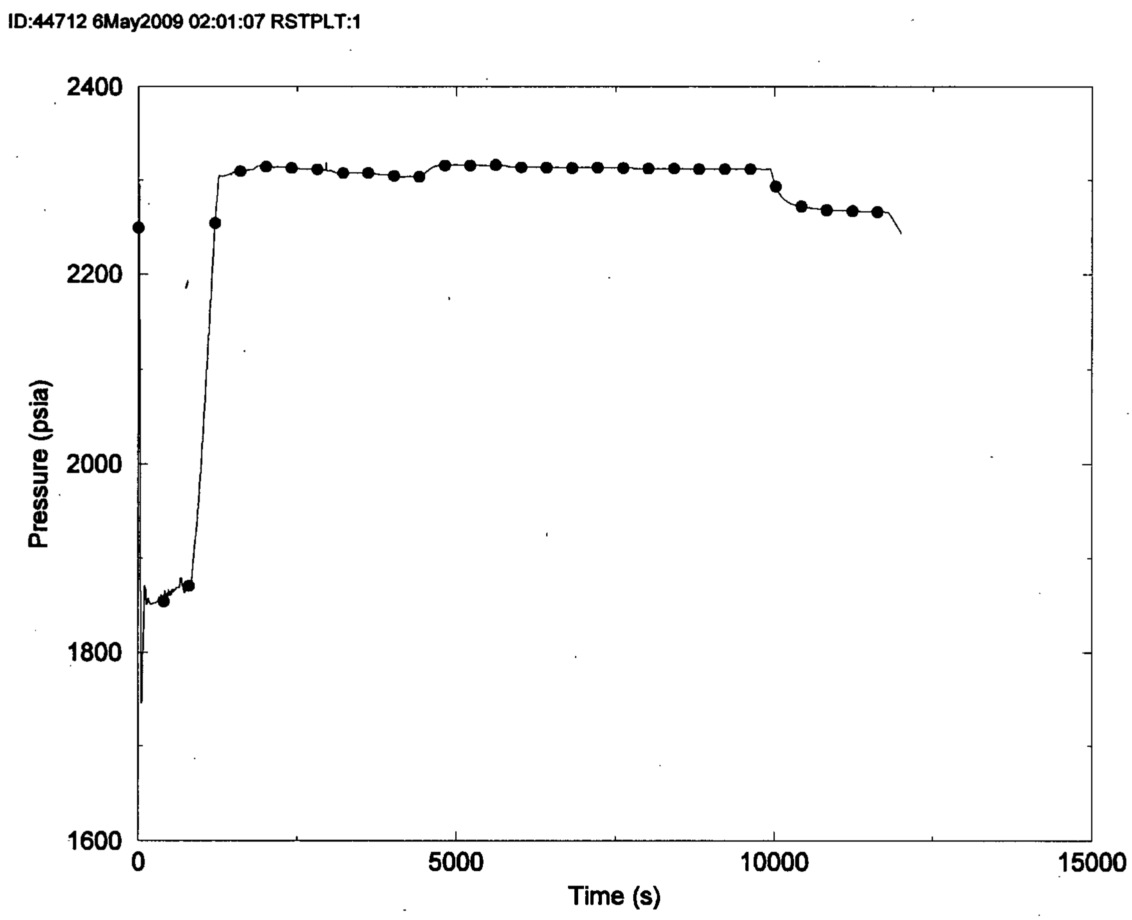

Figure 2: High Energy Line Break (Single Motor-Driven AFW Pump): Pressurizer Pressure

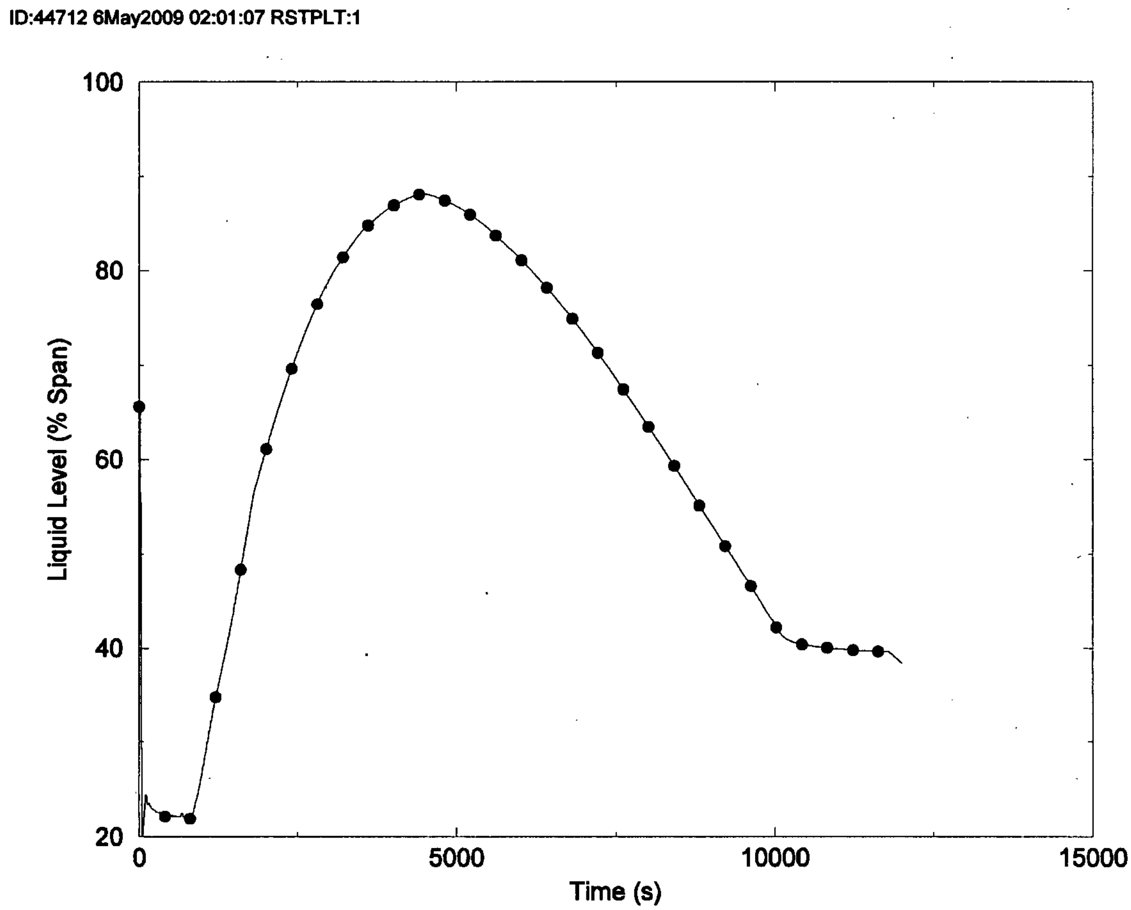

Figure 3: High Energy Line Break (Single Motor-Driven AFW Pump): Pressurizer Liquid Level

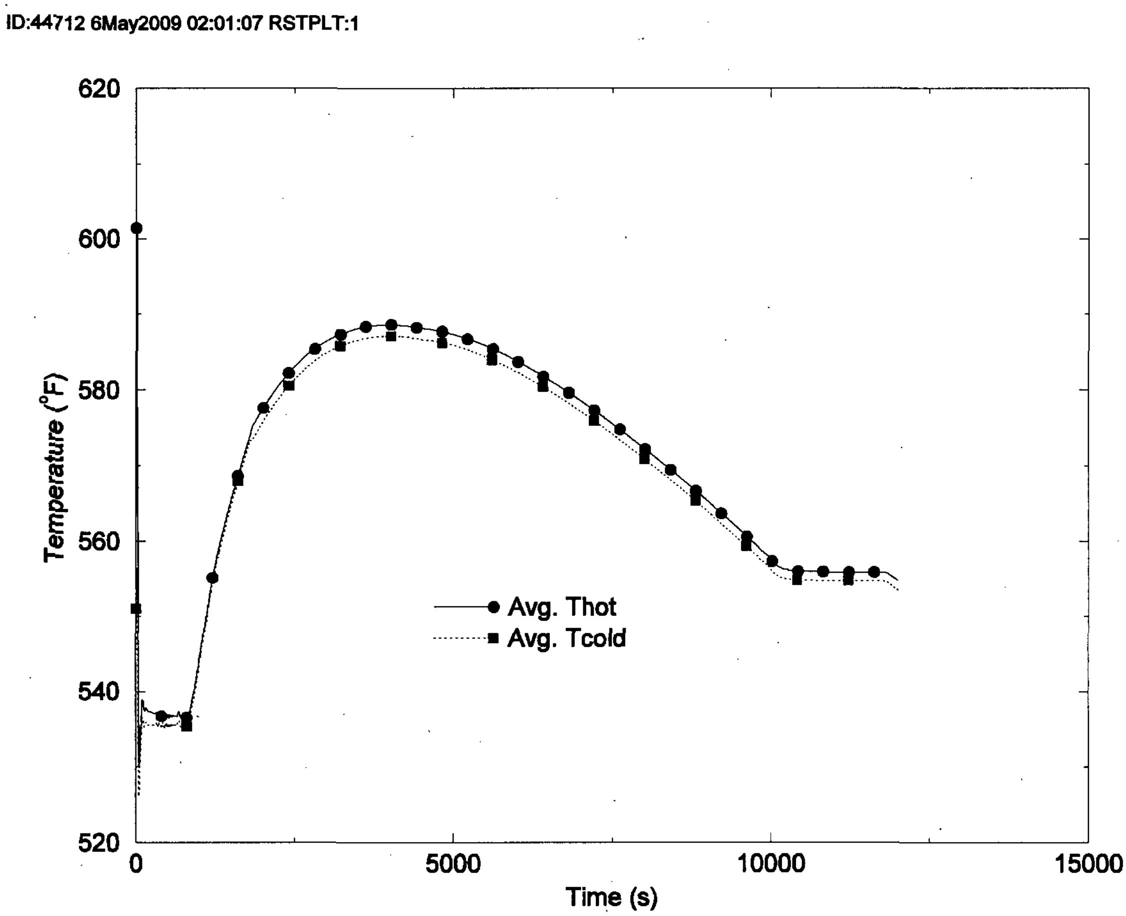

Figure 4: High Energy Line Break (Single Motor-Driven AFW Pump): RCS Loop Temperatures

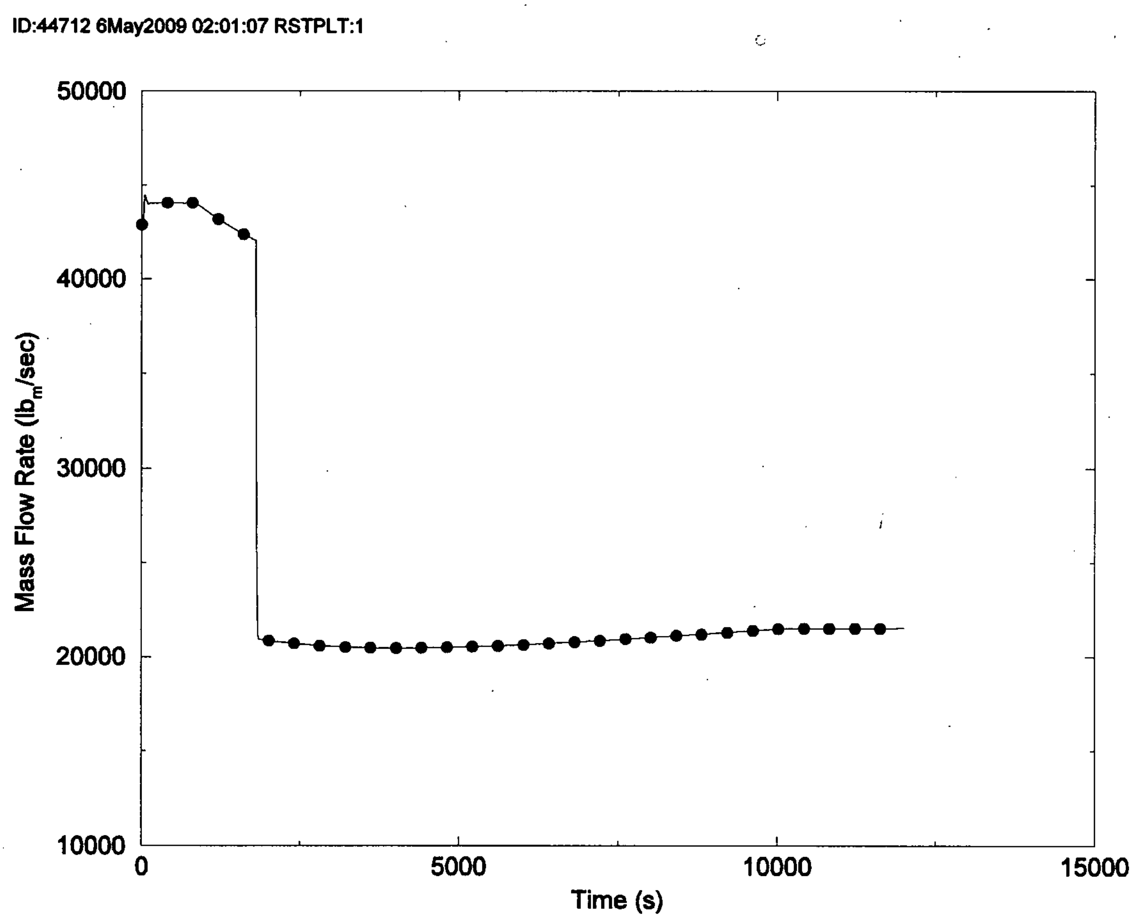

Figure 5: High Energy Line Break (Single Motor-Driven AFW Pump): RCS Total Loop Flow Rate

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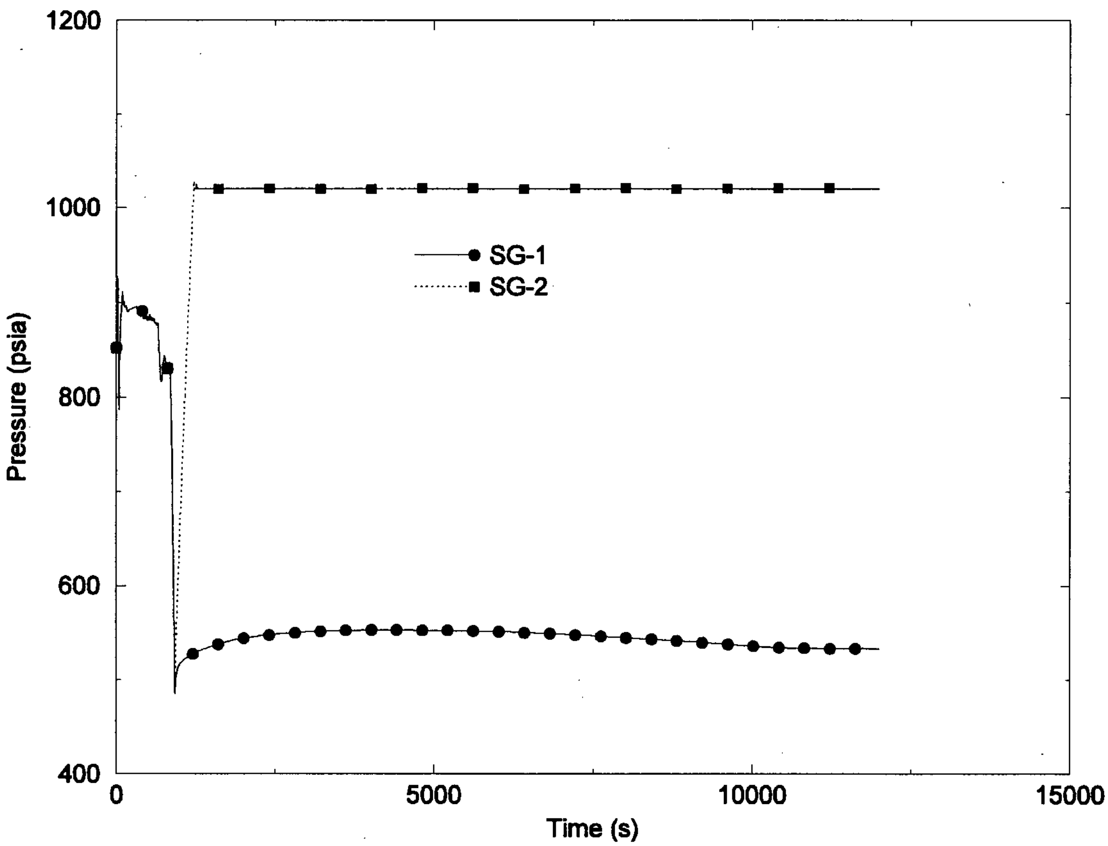

Figure 6: High Energy Line Break (Single Motor-Driven AFW Pump): Steam Generator Pressures

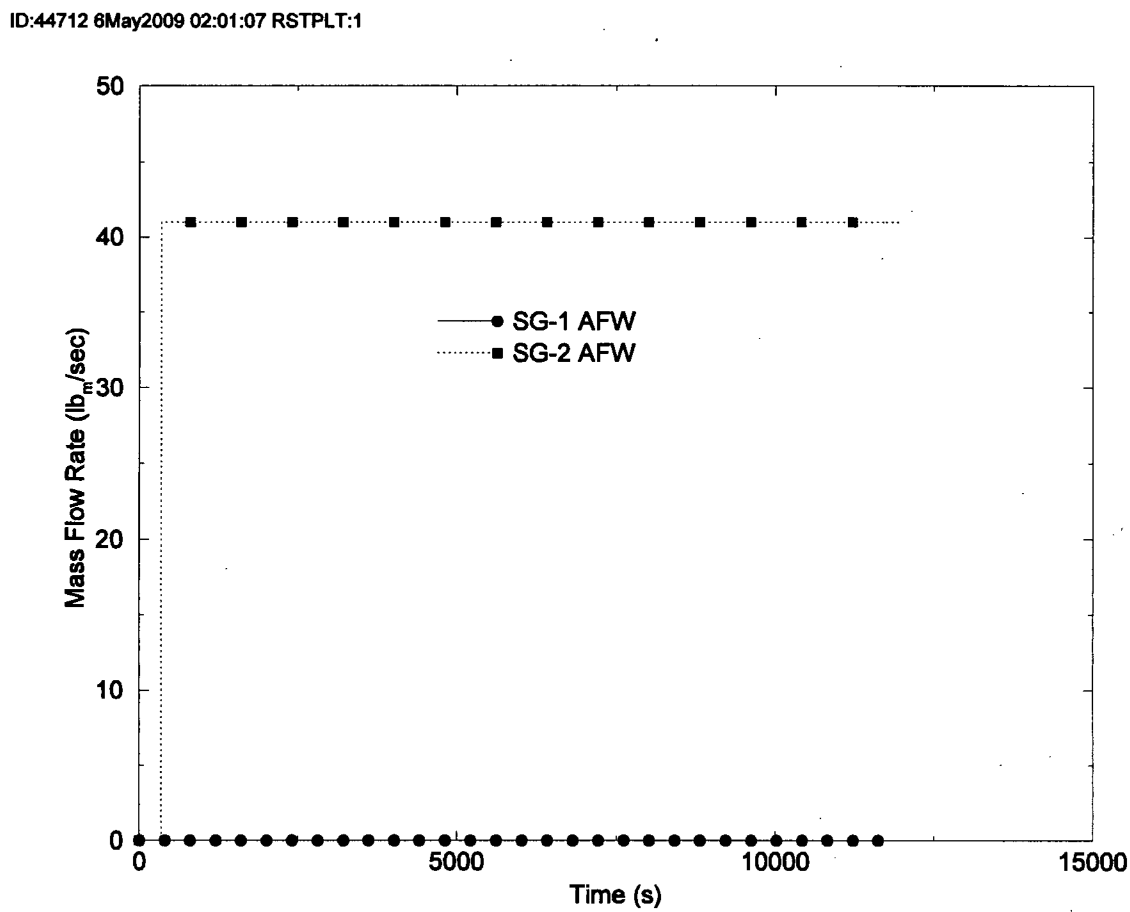

Figure 7: High Energy Line Break (Single Motor-Driven AFW Pump): Auxiliary Feedwater Flow Rates

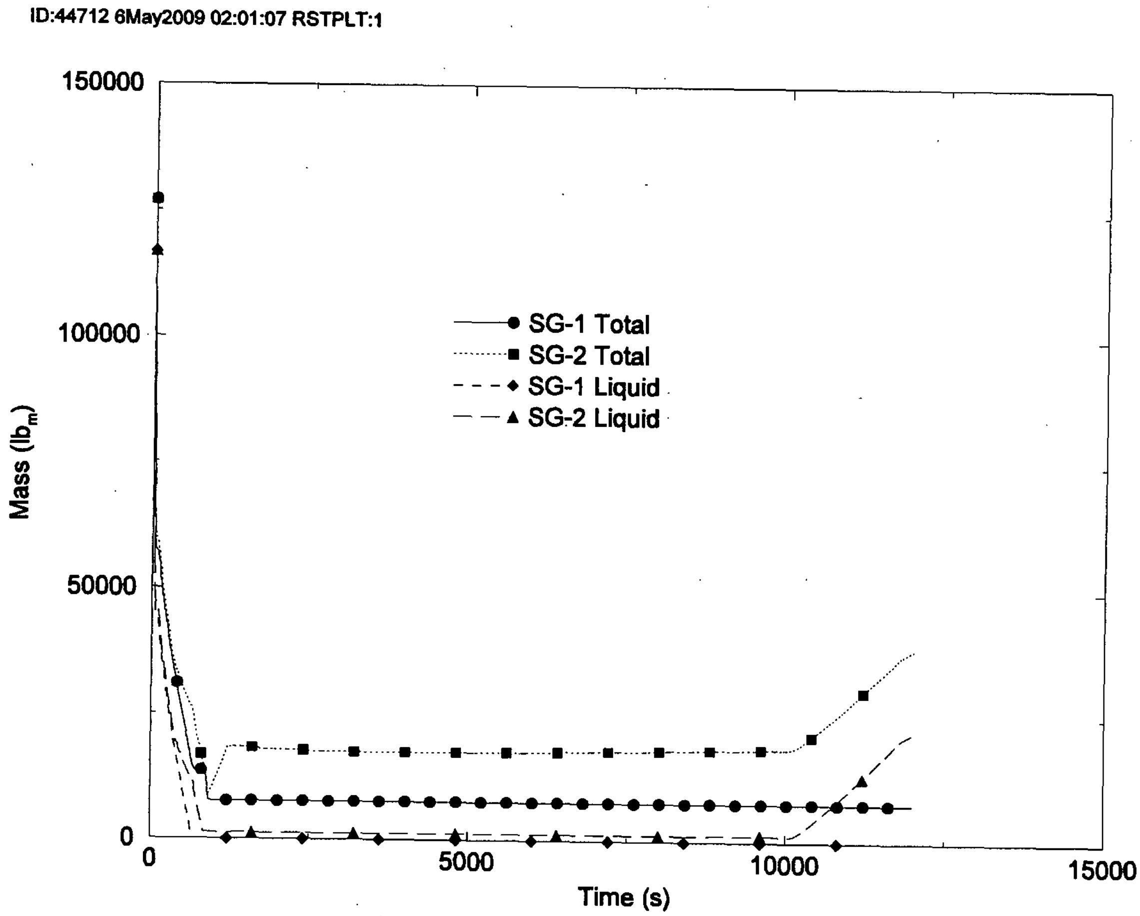

Figure 8: High Energy Line Break (Single Motor-Driven AFW Pump): Steam Generator Masses

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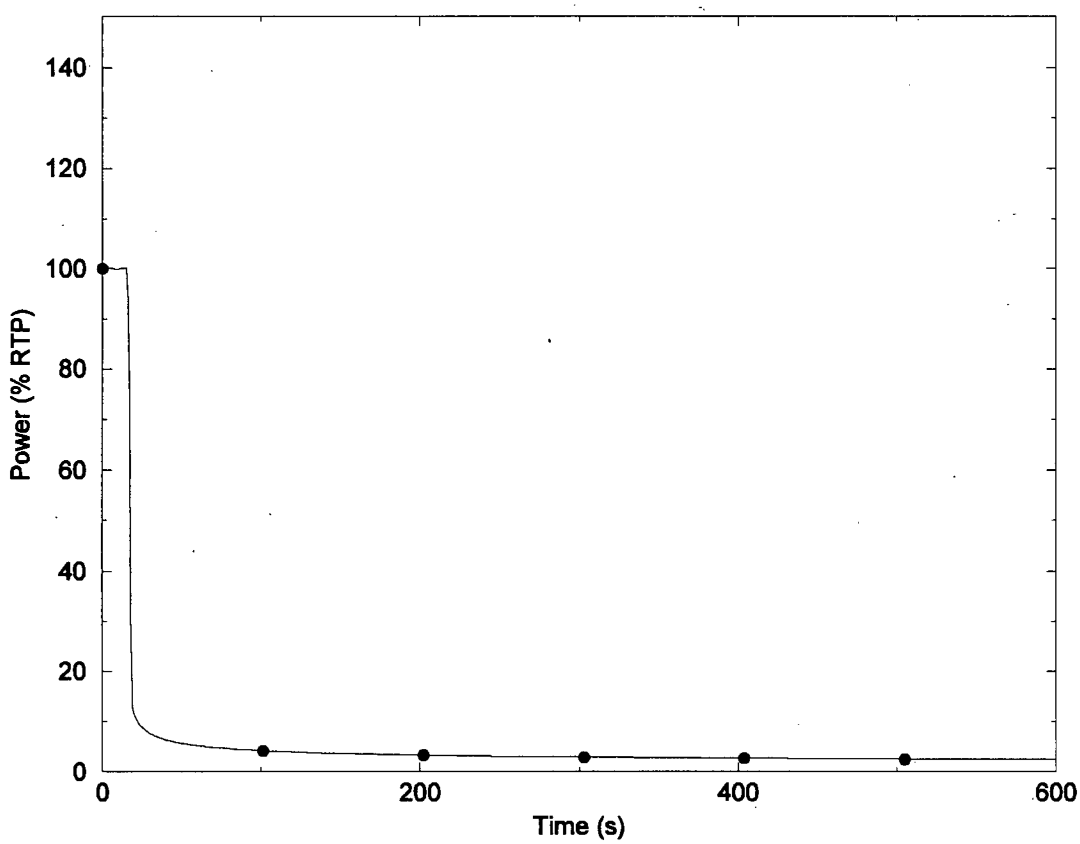

Figure 9: High Energy Line Break (No Motor-Driven AFW Pumps): Reactor Power

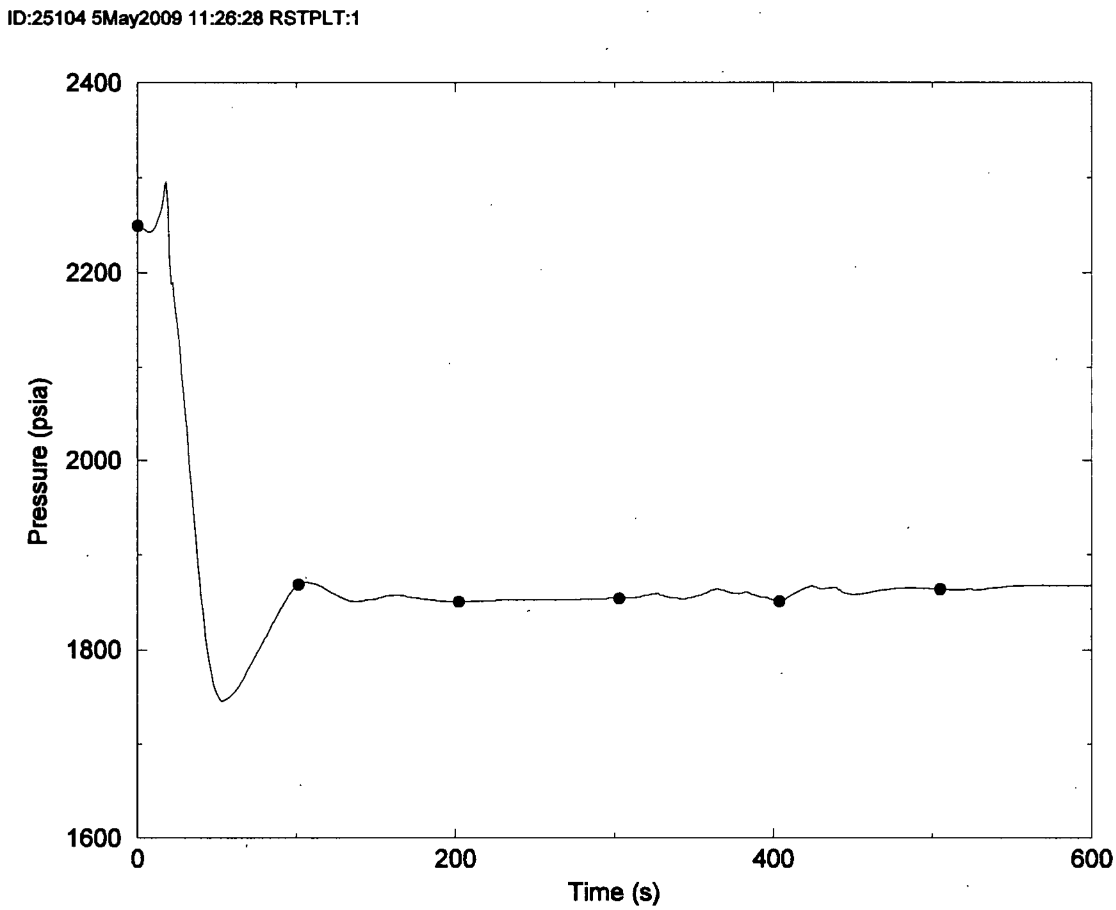

Figure 10: High Energy Line Break (No Motor-Driven AFW Pumps): Pressurizer Pressure

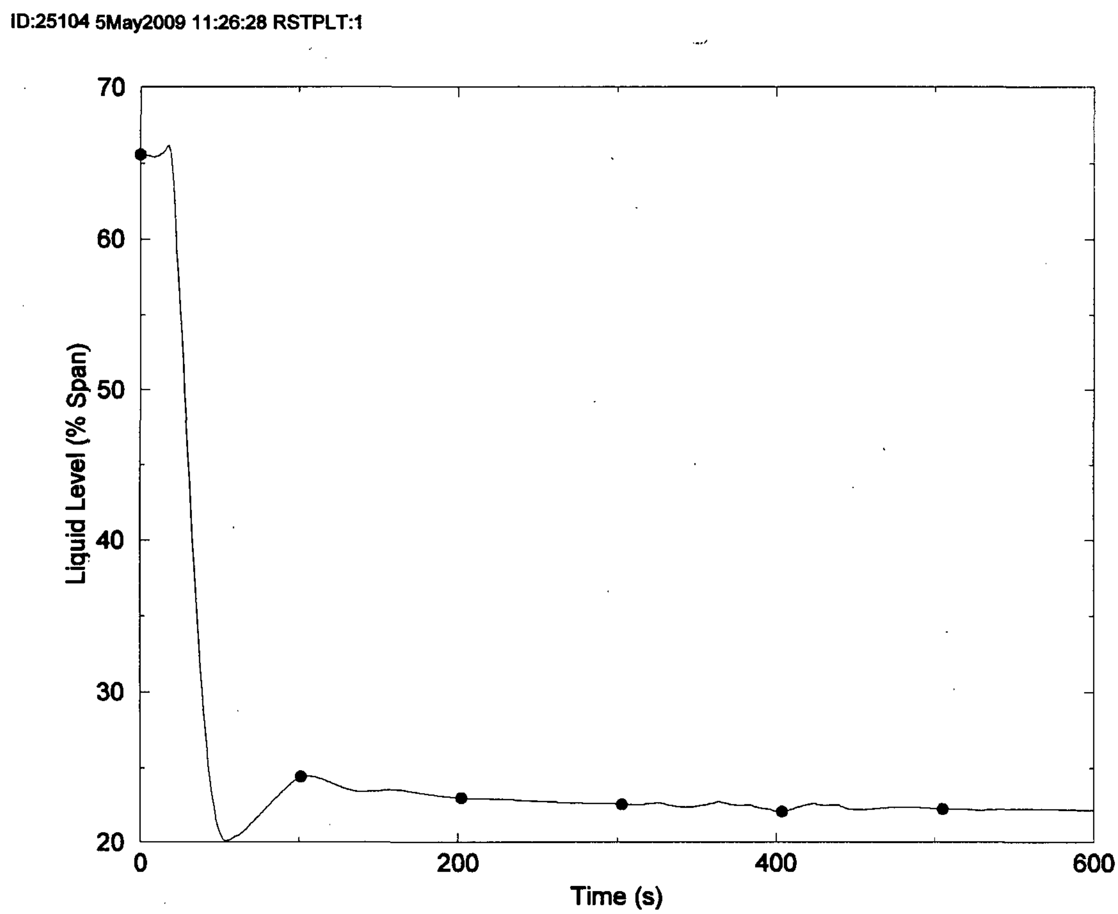

Figure 11: High Energy Line Break (No Motor-Driven AFW Pumps): Pressurizer Liquid Level

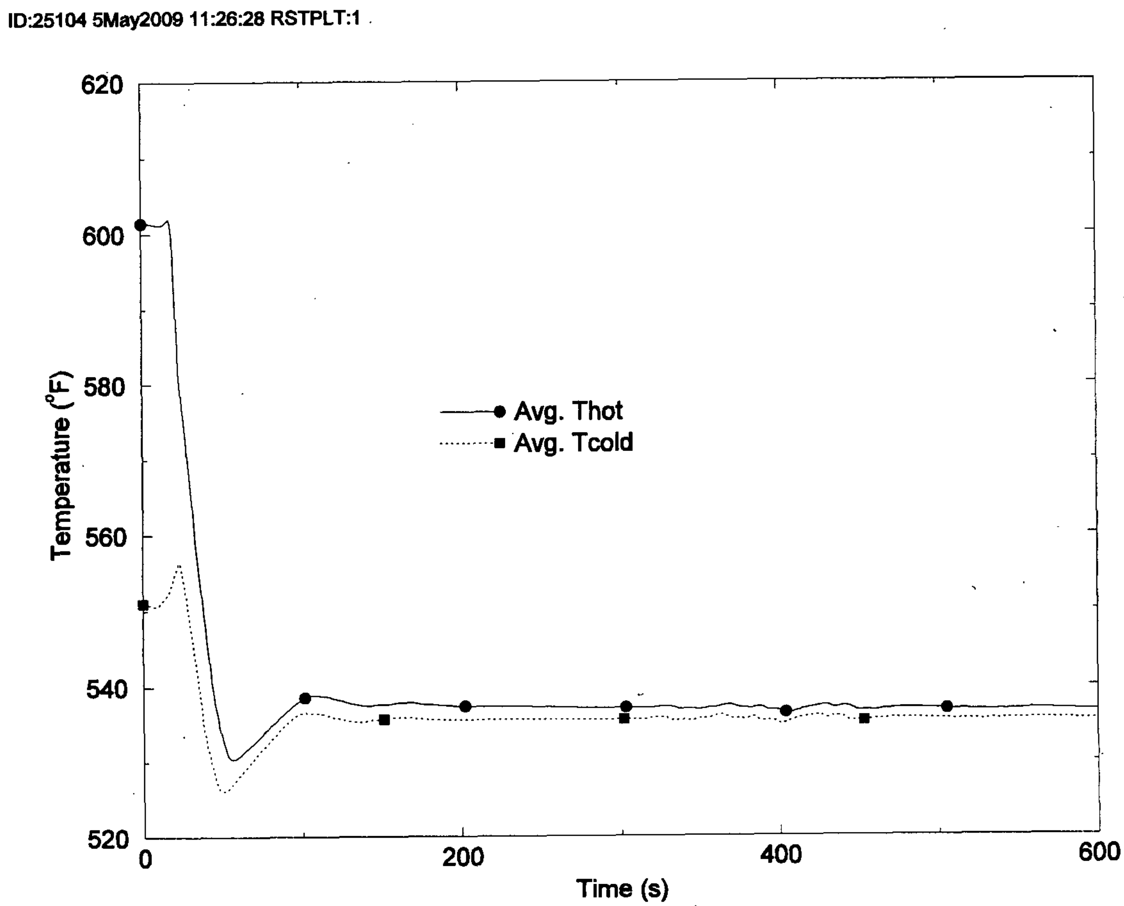

Figure 12: High Energy Line Break (No Motor-Driven AFW Pumps): RCS Loop Temperatures

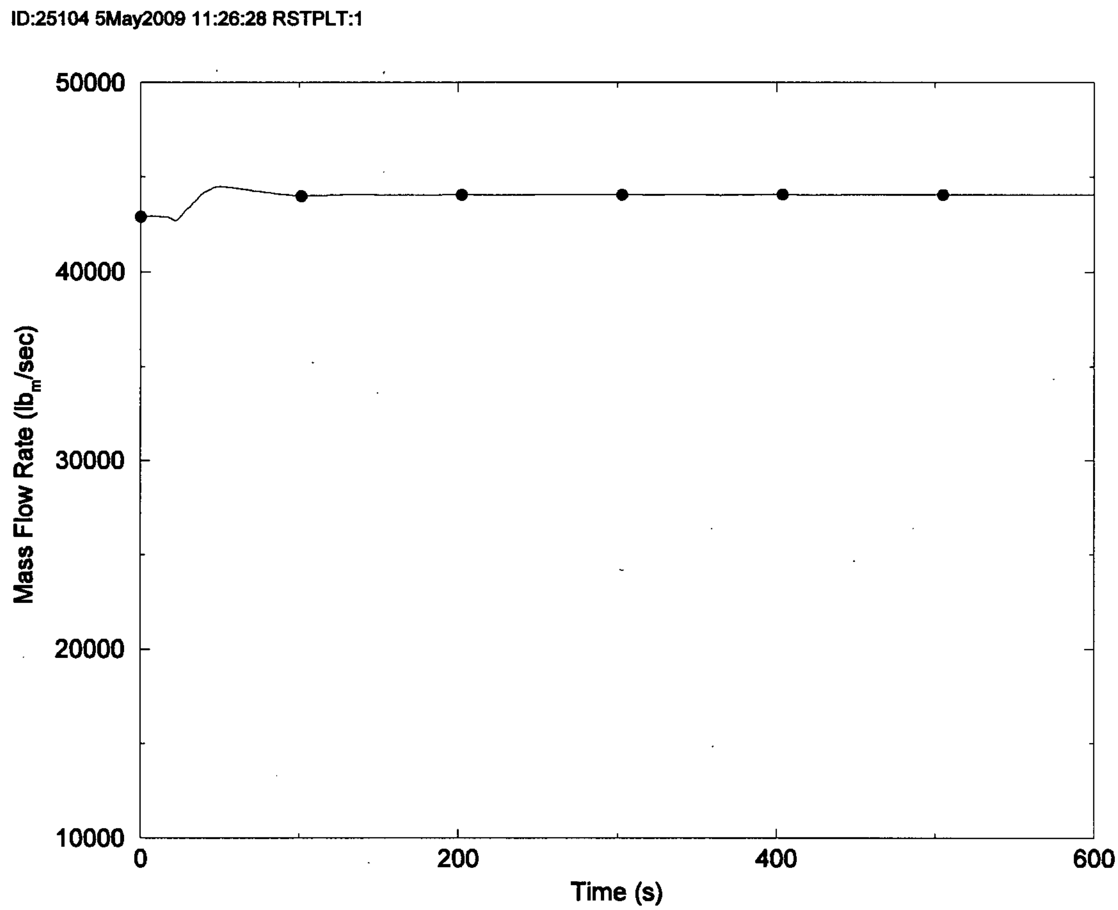

Figure 13: High Energy Line Break (No Motor-Driven AFW Pumps): RCS Total Loop Flow Rate

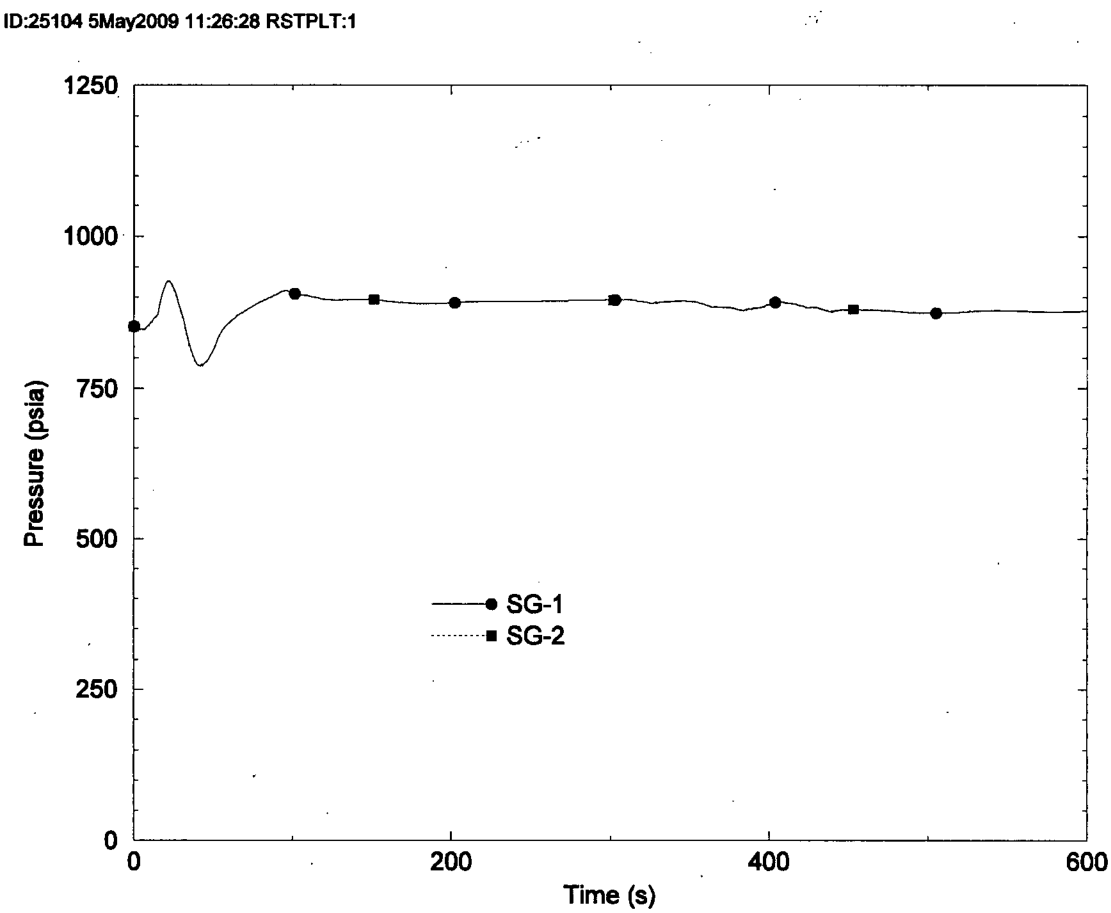

Figure 14: High Energy Line Break (No Motor-Driven AFW Pumps): Steam Generator Pressures

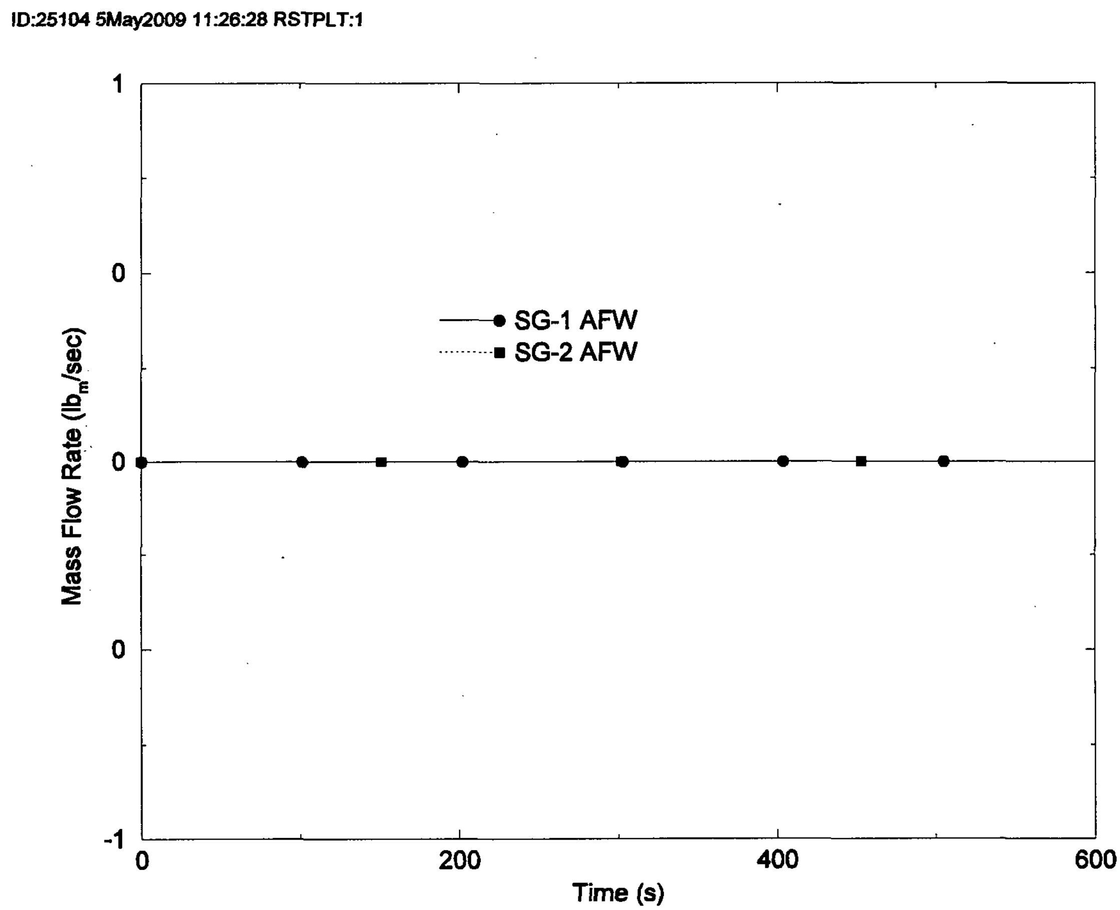

Figure 15: High Energy Line Break (No Motor-Driven AFW Pumps): Auxiliary Feedwater Flow Rates

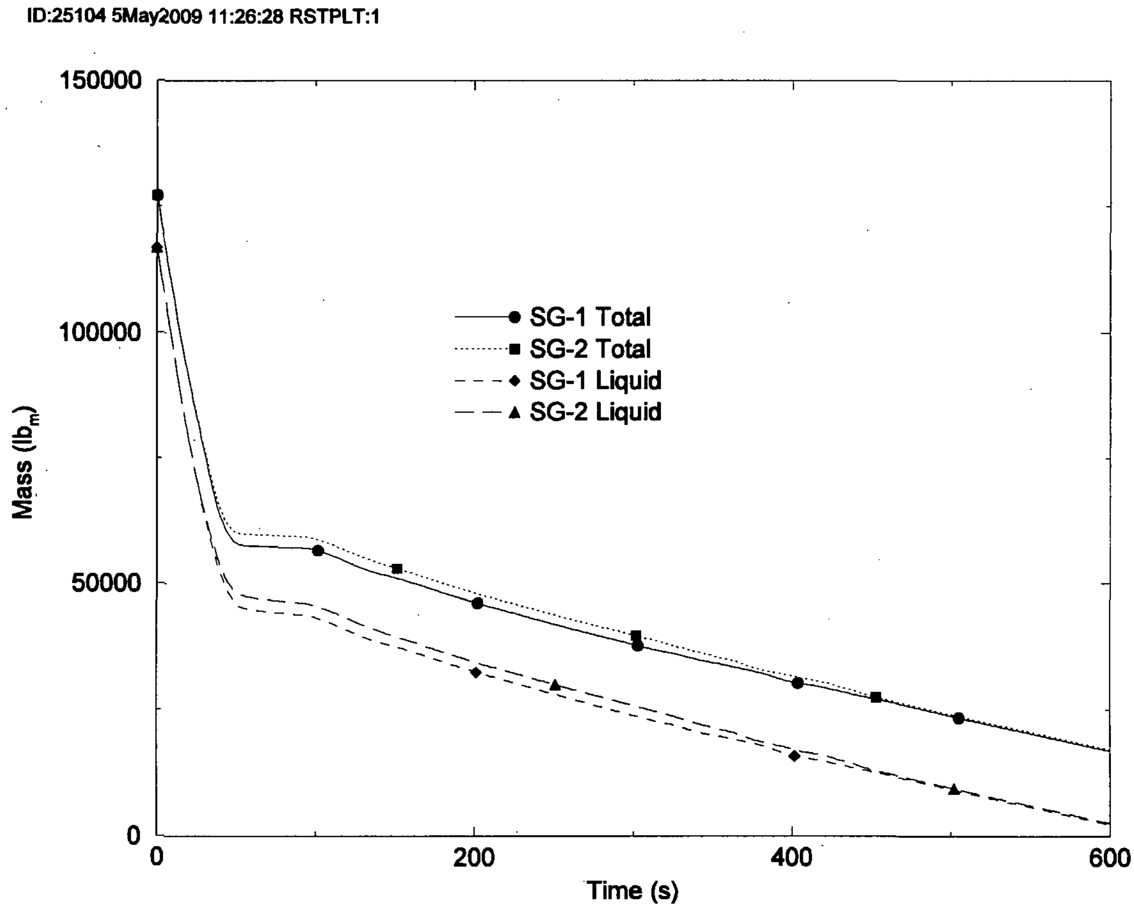

Figure 16: High Energy Line Break (No Motor-Driven AFW Pumps): Steam Generator Masses

SRXB-33

[2.8.5.4.5.a] For each of the boron dilution cases, provide a sequence of events table, identifying the alarm or trip that is actuated, indicating the time at which it occurs, and showing that there is adequate time available, for operator action, beginning at the time of the alarm or trip.

Response

St. Lucie Unit 1 current licensing basis boron dilution analysis calculates the time to criticality based on the time from event initiation. This basis is supported by previous communications with the NRC [References 1 and 2]. In Reference 1, the NRC informed FPL that they no longer require that FPL install dilution alarms at St. Lucie Unit 1. This was based on the evaluation performed by the NRC with the conclusion that the likelihood of the dilution resulting in criticality is very low. In Reference 2, FPL concurred with this position. EPU analysis is performed consistent with the current licensing basis. However, as documented in the response to SRXB-34, St. Lucie Unit 1 has several indications and alarms, including a boron dilution alarm, for operators to detect a boron dilution event.

The following table includes a sequence of events for each of the boron dilution cases analyzed for EPU. All the cases assume dilution flow from 3 charging pumps. The required time to operator action for Modes 2 through 5 is 15 minutes. The required time to operator action for Mode 6 is 30 minutes.

Case	Event Initiation Time (min.)	Time to Criticality (min.)
Startup (Mode 2) [(a)]	0	84.98
Hot Standby (Mode 3) [(a)]	0	84.98
Hot Shutdown (Mode 4) [(a)]	0	93.83
Hot Shutdown (Mode 4) [(b)]	0	28.36
Cold Shutdown (Mode 5) [(b)]	0	25.46
Refueling (Mode 6) [(b)]	0	39.56

Notes:
[(a)] Instantaneous Mixing Model
[(b)] Dilution Front Model

References (SRXB-33)

(1) Letter from R. A. Clark (USNRC) to R. E. Uhrig (FPL), Docket No. 50-335, dated April 26, 1982

(2) Letter L-82-233, from R. E. Uhrig (FPL) to R. A. Clark (USNRC), St. Lucie Unit 1 Docket No. 50-335 Boron Dilution Alarm, dated June 1, 1982

SRXB-34

Describe how the operator, working according to the applicable procedures, will locate the B dilution source and flow path(s), and terminate the dilution flow within 15 minutes after receipt of the assumed trip, alarm, or other indication.

Response

Chemical and volume control system (CVCS) regulates both the chemistry and the quantity of coolant in the reactor coolant system (RCS). The CVCS is designed to control the boron concentration in the RCS. A makeup system provides for changes in reactor coolant boron concentration and for reactor coolant chemistry control. Boric acid solution is directed into the volume control tank or to the common charging pump suction header. A chemical addition tank and metering pump are used to transfer chemical additives to the suction of the charging pumps which in turn are used to inject boron solution into the RCS. Boron dilution and chemical addition are conducted under strict administrative procedures which specify permissible limits on the rate and magnitude of any required change in boron concentration.

St. Lucie Conduct of Operations and Reactivity Management protocols require that the control room operator, with assigned reactivity change or dilution duties, remain "at the controls" of the involved equipment and to remain "focused" on the reactivity change or dilution function for the duration of the activities. Use of "peer checking" is utilized during a boron dilution activity.

An inadvertent boron dilution in any operational mode adds positive reactivity and, in Modes 1 and 2 (startup and power operations), can cause an approach to both the departure from nucleate boiling ratio (DNBR) and fuel centerline melt (FCM) limits. CVCS is equipped with the following indications and alarm functions, which will inform the reactor operator when a change in boron concentration in the reactor coolant system may be occurring:

- Volume control tank (VCT) level indication and high and low alarms
- Makeup flow indication and alarms
- Volume control tank isolation.

St. Lucie Unit 1 Abnormal Operating Procedures (AOP) provides actions to be accomplished in the event these indications are received. These actions include steps to stop dilution including stopping the primary water pump. These actions are performed from the Control Room and as such can be accomplished within 15 minutes after receipt of the assumed trip, alarm, or other indication.

In addition to the above, a boron dilution alarm is provided by the excore neutron monitoring system. St. Lucie Unit 1 Control Room has two annunciator windows (Channel A and Channel B), which provide indication of a boron dilution event. The Annunciator Response Procedures (ARPs) provide the operator guidance relative to instrument alarm confirmation indicating the occurrence of a boron dilution event. In this regard, the ARPs indicate that given confirmation of the following alarms:

- Rising count rate on the Excore Neutron Monitoring System,
- Rising count rate on Wide Range Nuclear Instrumentation, and,
- Shut Down Monitor red ALARM light is LIT.

Operator actions prescribed include:

- Stop diluting,
- Sample RCS, and
- Initiate actions associated with abnormal operating procedure that addresses isolation and recovery from dilution of RCS Loops

Dilution of the reactor coolant can be terminated by isolation of the makeup water system, by stopping either the makeup water pumps or the charging pumps, or by closing the charging isolation valves.

EPU LAR Attachment 5, LR Table 2.8.5.4.5-2 presents the results of the boron dilution analyses, which indicate that there is adequate time to operator action prior to reaching criticality.

SRXB-40

[2.8.5.6.2.h] Provide an updated licensing basis radiological release analysis to reflect radiological consequences of the above identified limiting release.

Response

The radiological release analysis for the steam generator tube rupture event was performed for EPU conditions and the radiological consequences are included in Attachment 1 of FPL letter L-2011-360 [Reference 1].

References (SRXB-40):

(1) R. L. Anderson (FPL) to U.S. Nuclear Regulatory Commission (L-2011-360), "Response to NRC Accident Dose Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request," September 2, 2011 Accession No. ML11251A159.

SRXB-42

Assess the credibility of an ATWS caused by mechanical common mode failure.

Response

Per Standard Review Plan (SRP) 15.8, an anticipated transient without scram (ATWS) is an anticipated operational occurrence (AOO) as defined in Appendix A to 10 CFR 50 followed by the failure of the reactor trip portion of the protection system. Since protection systems must satisfy the single-failure criterion, multiple failures or a common mode failure must cause the assumed failure of the reactor trip. The probability of an AOO, in coincidence with multiple failures or a common mode failure, is much lower than the probability of any of the other events that are evaluated under SRP Chapter 15. Therefore, an ATWS event cannot be classified as either an AOO or a design basis accident.

Under the requirements of 10 CFR 50.62 (ATWS Rule), St. Lucie Unit 1 has a diverse scram system (DSS) that assures diversity within the Reactor Protection System (RPS) from the sensor output to the interruption of power to the control rods. St. Lucie Unit 1 also complies with the requirements for a diverse turbine trip (DTT) and a diverse auxiliary feedwater actuation system (DAFAS).

St. Lucie Unit 1 thus complies with the failure modes consistent with the ATWS rule and has installed systems and equipment, which provide reasonable assurance that unacceptable plant conditions do not occur in the event of an ATWS.

SRXB-43

Discuss the applicability of ATWS analyses in cases in which a mechanical common failure is assumed.

Response

St. Lucie Unit 1 anticipated transient without scram (ATWS) analyses comply with the failure modes consistent with 10 CFR 50.62 (ATWS rule), and as per the requirements of the ATWS Rule, St. Lucie Unit 1 has installed a diverse scram system (DSS) that assures diversity within the Reactor Protection System (RPS) from the sensor output to the interruption of power to the control rods. St. Lucie Unit 1 also complies with the requirements for a diverse turbine trip (DTT) and a diverse auxiliary feedwater actuation system (DAFAS).

Response to SRXB-45 shows that the ATWS analyses, crediting DSS with the installed setpoints, provide adequate protection to prevent the RCS pressurization to 3200 psig, which is the ASME Service Level C limit applicable to ATWS events.

SRXB-44

Discuss an analysis for the mechanical - failure - induced ATWS event that credits the diverse turbine trip (DTT) and diverse auxiliary feedwater actuation (DAFAS); but not the DSS.

Response

St. Lucie Unit 1 anticipated transient without scram (ATWS) analyses comply with the failure modes consistent with 10 CFR 50.62 (ATWS Rule). Response to SRXB-45 shows that the diverse scram system (DSS) with the installed setpoints provides adequate protection to prevent the RCS pressurization to 3200 psig, which is the ASME Service Level C limit applicable to ATWS events. Since the installed systems and equipment, including the DSS, meet the 10 CFR 50.62 requirements, no separate ATWS analysis is done without crediting the DSS.

SRXB-45

The LR states that an ATWS event is not analyzed, due to the presence of the DSS, DTT, and DSS. If the setpoints for these systems are not identical to the setpoints used in the corresponding Chapter 15 accident analyses, then show that acceptable results would be obtained for ATWS analyses, at the proposed EPU power level, when using these setpoints.

Response

The setpoints for the diverse scram system (DSS) are not identical to the setpoints used in the corresponding UFSAR Chapter 15 accident analyses and the RPS. The evaluation below demonstrates the applicability of these setpoints for the EPU.

As addressed in EPU LAR Section 2.8.5.7, 10 CFR 50.62 specifies the design requirements with which St. Lucie Unit 1 complies. These requirements were imposed to reduce the probability of a severe anticipated transient without scram (ATWS) event, which is defined by the Nuclear Regulatory Commission (NRC) as the occurrence of an anticipated transient in conjunction with a failure of the reactor protection system (RPS) to trip the plant resulting in a reactor coolant system (RCS) overpressurization exceeding 3200 psig. No additional analyses are required by 10 CFR 50.62.

The limiting ATWS events are the loss of load (LOL) and the loss of main feedwater (LOFW). For the St. Lucie Unit 1 class of plants, Reference 1 demonstrated that a diverse scram system (DSS) with a 2450 psia trip setpoint and a 2-second response time would maintain the peak RCS pressure to <3200 psig for the limiting anticipated operational occurrences (AOOs). The pressure turn-around is dominated by the reactor trip initiated by DSS with minimal contribution from the moderator temperature coefficient. The DSS setpoint of 2450 psia is set such that it is above the reactor protection system RPS high pressurizer pressure trip (HPPT) setpoint and below the pressurizer safety valves (PSV) as-left setpoint, as described in Reference 1. St. Lucie Unit 1 also complies with the requirements for a diverse turbine trip (DTT) and a diverse auxiliary feedwater actuation system (DAFAS). However, as stated in Reference 1, the addition of a DTT and a DAFAS provides an insignificant reduction of ATWS risk if a DSS is installed, and the installation of the DSS alone meets the reliability goals of the ATWS rule.

No explicit ATWS analyses have been performed for St. Lucie Unit 1 at extended power uprate (EPU) conditions. However, an ATWS evaluation was performed for St. Lucie Unit 2, as presented below in the "St. Lucie Unit 2 ATWS Evaluation Overview," and its results are applicable to St. Lucie Unit 1. St. Lucie Units 1 and 2 are both the Combustion Engineering (CE) fleet class of plants referred to as the 2560 MWt class of plants in Reference 1. Table 1, "Nominal Conditions for St. Lucie Unit 1 and Unit 2 EPU," presents a comparison of St. Lucie Units 1 and 2 nominal conditions for the EPU. As can be seen in the table, both units are equivalent in design and have comparable nominal conditions. The slightly smaller pressurizer safety valve (PSV) capacity and reactor coolant system (RCS) volume for St. Lucie Unit 1 as compared to St. Lucie Unit 2 would cause a small increase in the peak pressure estimated for St. Lucie Unit 2 (2776 and 2747 psia for LOL and LOFW, respectively), but the increase would be negligible relative to the large margin available to meet the <3200 psig criterion. Hence, it can be concluded that the St. Lucie Unit 2 ATWS evaluation is applicable for St. Lucie Unit 1.

Since the ATWS evaluation for St. Lucie Unit 2 is applicable for St. Lucie Unit 1 the results from the St. Lucie Unit 2 ATWS evaluation would also directly apply to St. Lucie Unit 1. Hence, it can be concluded that the St. Lucie Unit 1 ATWS events for EPU would meet the acceptance criterion of < 3200 psig, which is the ASME Service Level C Limit applicable to ATWS events.

Table 1 – Nominal Conditions for St. Lucie Unit 1 and Unit 2 EPU

Parameter	EPU Nominal Conditions		
	St. Lucie Unit 1	**St. Lucie Unit 2**	**Units**
NSSS Power	3040	3040	MWt
Full Power Cold Leg Temperature	535 - 551	535 - 551	°F
RCS Volume	11061	11453	ft^3
Reactor Vessel Flow	375000	375000	gpm
Pressurizer Pressure	2250	2250	psia
Pressurizer Safety Valve Setpoint	2575 with 3% tolerance	2575 with 3% tolerance	psia
Total Pressurizer Safety Valve Rated Capacity	618000 (includes 3% accumulation)	636546 (includes 3% accumulation)	lbm/hr
Steam Generator Design	RSG	RSG	

St. Lucie Unit 2 ATWS Evaluation Overview

Discussion

As addressed in Reference 3, 10 CFR 50.62 specifies the design requirements with which St. Lucie Unit 2 complies. These requirements were imposed to reduce the probability of a severe anticipated transient without scram (ATWS) event, which is defined by the Nuclear Regulatory Commission (NRC) as the occurrence of an anticipated transient in conjunction with a failure of the reactor protection system (RPS) to trip the plant resulting in a reactor coolant system (RCS) overpressurization exceeding 3200 psig. No additional analyses are required by 10 CFR 50.62.

The limiting ATWS events are the loss of load (LOL) and the loss of main feedwater (LOFW). For the St. Lucie Unit 2 class of plants, Reference 1 demonstrated that a diverse scram system (DSS) with a 2450 psia trip setpoint and a 2-second response time would maintain the peak RCS pressure to <3200 psig for the limiting anticipated operational occurrences (AOOs). The pressure turn-around is dominated by the reactor trip initiated by DSS with minimal contribution from the moderator temperature coefficient. The diverse scram system (DSS) setpoint of 2450 psia is set such that it is above the RPS high pressurizer pressure trip (HPPT) setpoint and below the pressurizer safety valves (PSV) as-left setpoint.

St. Lucie Unit 2 also complies with the requirements for a diverse turbine trip (DTT) and a diverse auxiliary feedwater actuation system (DAFAS). However, as stated in Reference 1, the addition of a DTT and a DAFAS provides an insignificant reduction of ATWS risk if a DSS is installed, and the installation of the DSS alone meets the reliability goals of the ATWS rule.

Although no explicit ATWS analyses have been performed for St. Lucie Unit 2 at extended power uprate (EPU) conditions, the EPU loss of condenser vacuum (LOCV) and feed line break (FLB) scenarios presented in Reference 3 provide adequate justification that LOL and LOFW scenarios with ATWS considerations would continue to meet the criteria as presented in References 1 and 2. However it is important to note that the FLB analysis is a postulated accident, not an anticipated transient/AOO, and is only utilized as a conservative representation of the LOFW transient. Note that the current and the EPU LOCV and FLB analyses applied more conservative inputs and assumptions with respect to the RCS overpressurization scenarios than were required in the ATWS analyses, as described in Table 2 "Input Parameters for LOCV, FLB and ATWS," below. The EPU analyses clearly demonstrate that the St. Lucie Unit 2 DSS will be effective in limiting peak RCS pressures to <3200 psig for these limiting ATWS scenarios, as described below.

Loss of Load

1. The ATWS LOL analysis [References 1 and 4] assumes instantaneous termination of all feedwater flow and steam flow to the condenser, and delays reactor trip until the DSS setpoint of 2450 psia is reached. The peak RCS pressure was ~2600 psia.

2. The EPU LOCV analysis [Reference 3] assumes the same instantaneous termination of feedwater and steam flows, and the reactor trips on the RPS HPPT at a setpoint of 2415 psia. The peak RCS pressure was 2669 psia.

Loss of Feedwater

1. The ATWS LOFW [References 1 and 2] assumes instantaneous termination of all feedwater flow, and delays reactor trip until the DSS setpoint of 2450 psia is reached.

2. EPU FLB [Reference 3] assumes the same instantaneous termination of feedwater; but in addition, the 0.21 ft^2 break depletes the steam generator inventory more quickly than the simple LOFW (EPU LAR Attachment 5, Fig. 2.8.5.2.4-4), forcing a degradation in heat transfer and a rapid RCS heatup. The steam generator low level trip is ignored and the reactor trips on RPS HPPT (2460 psia setpoint).

The RPS HPPT and the PSVs as-left setpoints have not changed for the EPU. With the DSS setpoint also unchanged at 2450 psia, it can be judged from the results of the current LOCV and FLB analyses that the peak pressure of ATWS LOL and LOFW at EPU conditions would remain <3200 psig.

This is further substantiated from the EPU LOCV and FLB results by a conservative adjustment to account for delaying the reactor trip from the RPS HPPT trip to the DSS trip. With the application of the conservative adjustment, the peak RCS pressure for ATWS LOL and LOFW at EPU conditions is seen to remain much less than 3200 psig, as described below:

EPU LOCV Adjustment - If the EPU LOCV trip is delayed from the RPS HPPT to the DSS trip (i.e., delayed until 2450 psia with an additional 0.85 second response time as per Table 2 “Input Parameters for LOCV, FLB and ATWS,” below), then the peak RCS pressure would increase by 107 psi, from 2669 to 2776 psia.

EPU LAR Attachment 5, Section 2.8.5.2.1, Table 2.8.5.2.1-2 provides the HPPT setpoint of 2415 psia at 16.30 seconds, while the PSVs open at a pressure setpoint of 2575 at 18.195 seconds. Using these data, the rate of pressurization is about 84 psi/sec. If the trip is delayed to 2450 psia with 0.85 seconds additional response, then the peak pressure would increase by 107 psia [= 84*0.85 + (2450-2415)].

EPU FLB Adjustment - If the EPU FLB trip is changed from the RPS HPPT to the DSS trip, (i.e., tripped at 2450 with an additional 0.6 second response time as per Table 2 “Input Parameters for LOCV, FLB and ATWS,” below), then the peak RCS pressure would increase 43 psi, from 2704 to 2747 psia.

EPU LAR Attachment 5, Section 2.8.5.2.4, Table 2.8.5.2.4-2 provides the HPPT setpoint of 2460 psia at 31.04 seconds, while the PSVs open at a pressure setpoint of 2575 at 32.66 seconds. Using these data, the rate of pressurization is about 71 psi/sec. If the trip remains at 2460 psia (conservative with respect to 2450 psia) with 0.6 seconds additional response, then the peak pressure would increase 43 psia [=71*0.6].

<u>Conclusion</u>

Based on the extrapolation of the EPU LOCV and FLB results to account for a reactor delay associated with waiting for a DSS trip while ignoring the RPS HPPT trip, it is concluded that the DSS trip set at 2450 psia will maintain the peak RCS pressure during the limiting ATWS events to <3200 psig for the EPU.

References (SRXB-45):

(1) CE-NPSD-354 Task-494, Rev. 0, “Functional Design Specification for the Diverse Scram System for Compliance with the ATWS Rule 10CFR50.62.”

(2) CENPD-263-P, Rev. 0, “ATWS Early Verification Response to NRC Letter of February 15, 1979, for Combustion Engineering NSSS’s.”

(3) R.L. Anderson (FPL) to U.S. Nuclear Regulatory Commission (L-2011-021), “License Amendment Request for Extended Power Uprate,” February 25, 2011, Accession No. ML110730116.

(4) CENPD-158, through Rev. 1, “ATWS Analyses, Analysis of Anticipated Transients without Reactor Scram in Combustion Engineering NSSS’s.”

Table 2 – Input Parameters for LOCV, FLB and ATWS

Parameter	EPU LOCV value	EPU FLB value	ATWS value	Units	Comments
NSSS Power	3044.2	3044.2	2710 (LOFW) 2560 (LOL)	MWt	Per References 1 & 2 of the "St. Lucie Unit 2 ATWS Evaluation Overview," the LOFW ATWS analyses assumed 2710 MW NSSS power for the 2560 MW Class of plants, whereas the LOL ATWS analyses of References 1 & 4 of the "St. Lucie Unit 2 ATWS Evaluation Overview," assumed 2560 MW for the 2560 MW Class.
RCS Volume	Nominal	Nominal	Nominal		
Full Power Cold Leg Temperature	532	532	546	°F	Lower temperature is conservative for overpressure, because it lowers SG pressure which delays MSSV opening. ATWS used a nominal value. EPU used a minimum value including uncertainties. Therefore, the EPU value is more adverse than ATWS required.
Reactor Vessel Flow	Minimum	Minimum	Nominal		The difference between the minimum and nominal RCS flow rates has a negligible impact on the peak RCS pressure for the ATWS events.
Pressurizer Pressure	2180	2180	2250	psia	Lower initial PZR pressure setpoint for the EPU delays the HPPT trip, therefore resulting in a higher RCS pressure.
Pressurizer Water Volume	932	927	782 (LOFW) 769 (LOL)	ft^3	Higher initial PZR level for the EPU causes a faster rate of pressurization once heatup begins, therefore resulting in a higher RCS pressure.
Total PORV Relief Capacity	Not credited	Not credited	302,670 (LOFW) 303,800 (LOL)	lbm/hr	Unavailable PORVs makes the overpressurization for the EPU more adverse than ATWS required.
Pressurizer Safety Valve Setpoint	2575	2575	2500	psia	Delayed opening of the PSVs makes the overpressurization for the EPU more adverse than ATWS required.
Total Pressurizer Safety Valve Rated Capacity	636,546	636,546	592,130 (LOFW) 990,000 (LOL)	lbm/hr	

Parameter	EPU LOCV value	EPU FLB value	ATWS value	Units	Comments
Pressurizer Pressure Control System	Not credited	Not credited	Operating		Unavailable spray flow makes the overpressurization for the EPU more adverse than ATWS required.
Pressurizer Level Control System	Not credited	Not credited	Operating		Unavailable letdown flow makes the overpressurization for the EPU slightly more adverse than ATWS.
Steam Generator Pressure	707	707	850	psia	Lower SG pressure is conservative for overpressure, because it delays MSSV opening. ATWS used a nominal value. EPU used a minimum value with uncertainties. Therefore, the EPU value is more adverse than ATWS required.
SG Water Level	Minimum	Minimum	Nominal		Minimum SG water level (inventory) is conservative as it absorbs less energy from the primary system during the event and results in a faster rate of RCS pressurization.
High Pressurizer Pressure Trip Setpoint	2415 (RPS)	2460 (RPS)	2450 (DSS)	psia	
High Pressurizer Pressure Trip Response Time	1.15	1.4	2	sec	DSS response time is slightly greater than the RPS HPPT. For EPU LOCV: EPU LAR Attachment 5, Table 2.8.5.2.1-2 (Reactor trip time-HPPT Setpoint reached) For EPU FLB: EPU LAR Attachment 5, Table 2.8.5.2.4-2 [Reactor trip time-HPPT Setpoint reached + conservative delay (0.99-0.74)]
AFAS Setpoints	N/A	N/A	N/A		AFW does not impact peak RCS pressure since no AFW flow enters the SGs prior to the time of peak RCS pressure.
Peak RCS Pressure	2669	2704	~2600	psia	ATWS LOL pressure is comparable to the LOCV and FLB pressure at pre-EPU power.

SRXB-47

Demonstrate the validity of the sampling functions for safety injection tank cover pressure, safety injection tank temperature, and RWST temperature by providing a histogram of observed pressures and temperatures collected from recent surveillance data that can be compared to the Figure 3-6 scatter plots of these sampled parameters. For RWST temperature please also provide a scatter plot similar to those in Figure 3-6.

Response

The safety injection tank (SIT) pressure is sampled from 200 psig to 280 psig to cover the range of SIT pressures as presented in section 3.5.1 of the current Technical Specifications (TS) and as presented in St. Lucie Unit 1 EPU LAR Attachment 1, section 3.1, item 17 "TS 3/4.5.1, EMERGENCY CORE COOLING SYSTEMS (ECCS) – SAFETY INJECTION TANKS (SIT)" which conveys the proposed TS. The SIT temperature is sampled with a uniform distribution over the range of 80.5 °F - 124.5 °F (Technical Specification 3.6.1.5[1]). The RWT temperature is not sampled; it is set to 104 °F (Technical Specification maximum plus uncertainty, Technical Specification 3.5.4). Table 3-3 in ANP-2903(P) Rev. 1 (Attachment 2 of Reference 1) provides the RWT temperature and shows that this is a point parameter, not a ranged parameter. Figure 47-1 through Figure 47-4 show the RLBLOCA analysis values along with the St. Lucie Unit 1 plant data.

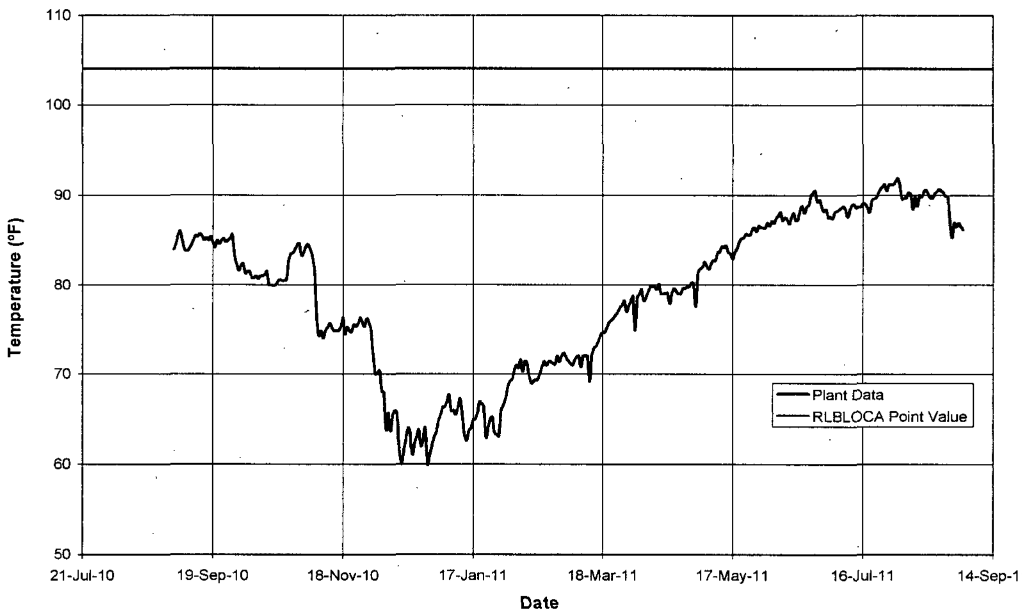

Figure 47-1 RWT Temperature – Plant Data and RLBLOCA Analysis Value

1 Table 3-2 in ANP-2903 Rev. 1 (Reference 1) notes that per the RLBLOCA methodology, the SIT temperature is coupled to the containment temperature. The maximum of this range is tied to the Technical Specification.

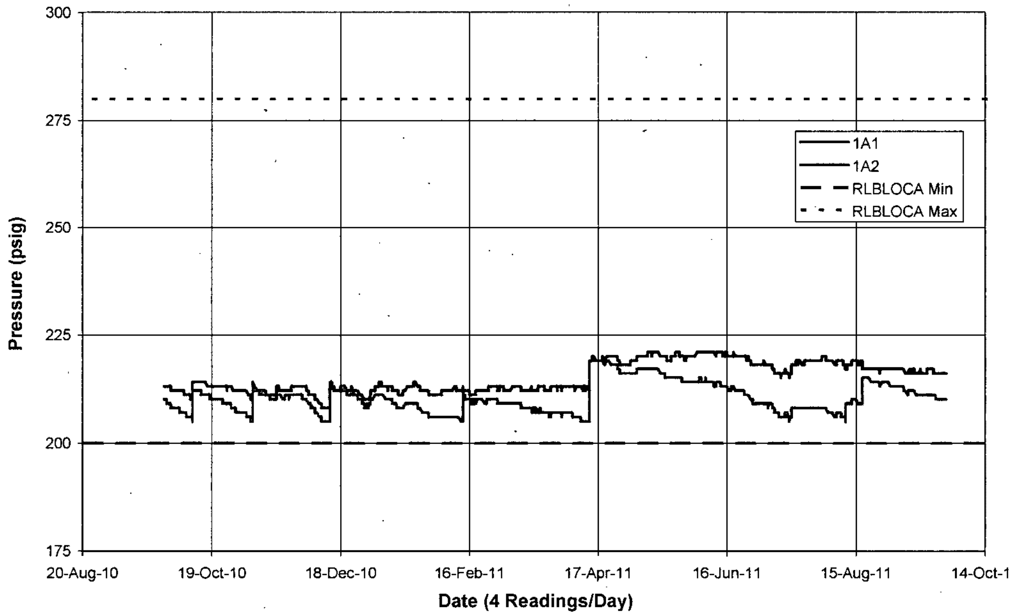

Figure 47-2: SIT Pressure – Plant Data (1A Tanks) and RLBLOCA Analysis Sampling Range

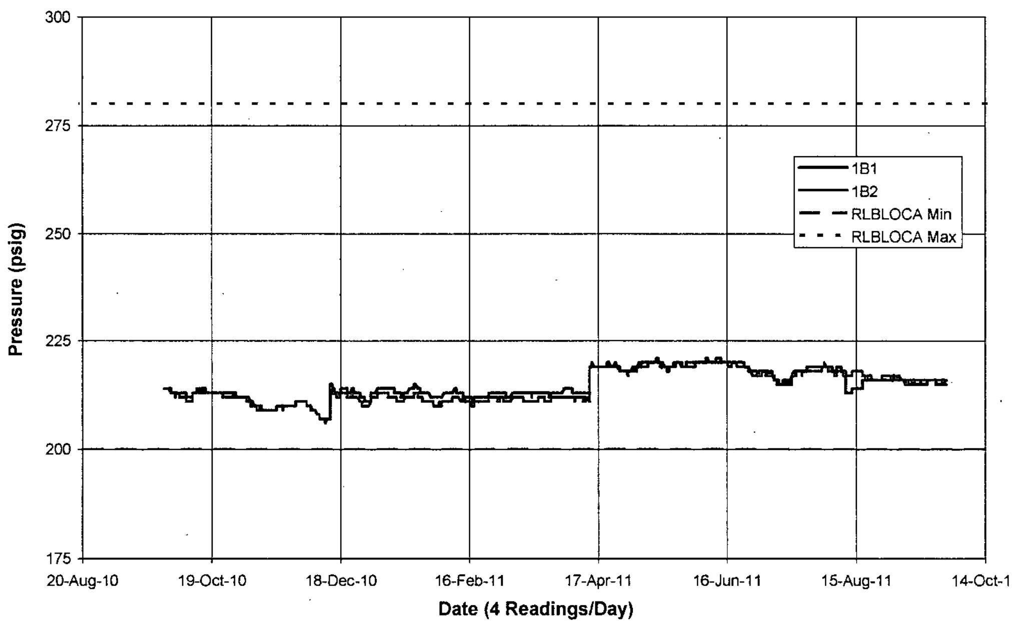

Figure 47-3: SIT Pressure – Plant Data (1B Tanks) and RLBLOCA Analysis Sampling Range

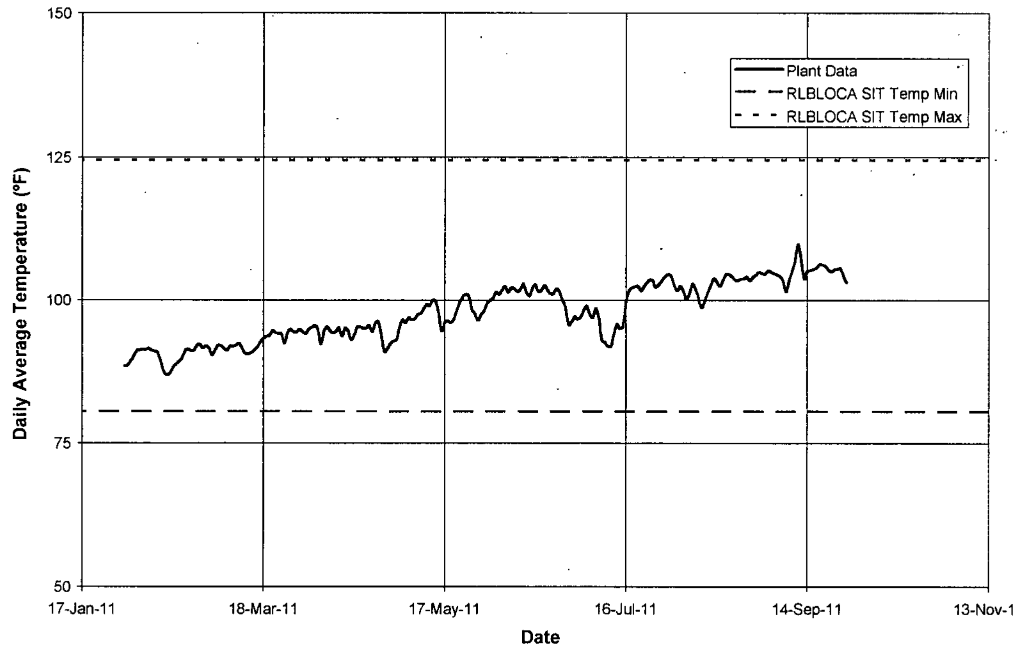

Figure 47-4: Containment Air Temperature – Plant Data and RLBLOCA Analysis Sampling Range

References (SRXB-47):

(1) R. L. Anderson (FPL) to U.S. Nuclear Regulatory Commission, (L-2011-206), Information Regarding Areva LOCA and Non-LOCA Methodologies Provided in Support of the St. Lucie Unit 1 License Amendment Request for Extended Power Uprate, May 27, 2011 (ML11153A048).

SNPB-16

Please provide the results of the seismic LOCA loads analysis for the limiting break. Identify the maximum hot channel deformation/flow area reduction, the maximum hot bundle flow area reduction, the peak linear heat rate for the hottest rod in the assembly undergoing maximum deformation. Also, provide the linear heat rate for the bundle containing the rod with the max deformation. The analysis should provide the plots typical of the limiting large break LOCA analysis given in a chapter 15 analysis.

Response

Horizontal accident conditions (seismic and LOCA) analyses were performed to assess the structural adequacy of CE14-HTP spacer grids for the St. Lucie Unit 1 at Extended Power Uprate conditions. The analyses calculated a maximum combined (SRSS seismic plus LOCA) lateral impact load that is well below the tested grid crushing load. Furthermore, the lateral impact load is within the elastic range of behavior for the spacer grid and therefore, there is no permanent deformation/flow area reduction. Thus, the limiting break analysis remains applicable for the whole core and the requirement of maintaining a coolable geometry is not challenged under accident conditions.

The LBLOCA figures in Section 15.4 of the St. Lucie Unit 1 UFSAR were reviewed and the following figures are provided to supplement those found in ANP-2903(P) Rev. 1 (Attachment 2 of Reference 1). Table 16-1 provides a list of the Chapter 15 FSAR figures and a cross-reference to where these figures are found in ANP-2903(P) Rev. 1 or in this RAI response.

References (SNPB-16):

(1) R. L. Anderson (FPL) to U.S. Nuclear Regulatory Commission, (L-2011-206), Information Regarding Areva LOCA and Non-LOCA Methodologies Provided in Support of the St. Lucie Unit 1 License Amendment Request for Extended Power Uprate, May 27, 2011 (ML11153A048).

Table 16-1: FSAR Chapter Figures and Comparative RLBLOCA Figure

FSAR Ch. 15 Plot		RLBLOCA Analysis Figure	
Number	**Title**	**Location**	**Figure Number**
15.4.1-2	Normalized Power vs. Time	RAI SNPB-16	Figure 16-1
15.4.1-3	SITs Discharge Rates	ANP-2903(P) R1	Figure 3-16
15.4.1-4	HPSI Flow Rates		
15.4.1-5	LPSI Flow Rates		
15.4.1-6	Upper Plenum Pressure During Blowdown	ANP-2903(P) R1	Figure 3-17
15.4.1-7	Total Break Flow Rate During Blowdown	ANP-2903(P) R1	Figure 3-12
15.4.1-8	Average Core Inlet Flow Rate During Blowdown	RAI SNPB-16	Figure 16-2
15.4.1-9	Hot Channel Inlet Flow Rate During Blowdown	RAI SNPB-16	Figure 16-3
15.4.1-10	PCT Node Fluid Quality During Blowdown	RAI SNPB-16	Figure 16-4
15.4.1-11	PCT Node Fuel (Average), Cladding and Fluid Temperatures During Blowdown	RAI SNPB-16	Figure 16-5
15.4.1-12	PCT Node Heat Transfer Coefficient During Blowdown	RAI SNPB-16	Figure 16-6
15.4.1-13	PCT Node Heat Flux During Blowdown	RAI SNPB-16	Figure 16-7
15.4.1-14	Containment Pressure	ANP-2903(P) R1	Figure 3-21
15.4.1-15	Upper Plenum Pressure After Blowdown	ANP-2903(P) R1	Figure 3-17
15.4.1-16	Downcomer Collapsed Liquid Level	ANP-2903(P) R1	Figure 3-18
15.4.1-17	Core Effective Flooding Rate	Not Provided[2]	
15.4.1-18	Core Collapsed Liquid Level	ANP-2903(P) R1	Figure 3-20
15.4.1-19	Core Quench Level	RAI SNPB-16	Figure 16-8
15.4.1-20	PCT Node Heat Transfer Coefficient	RAI SNPB-16	Figure 16-9
15.4.1-21	PCT Node and Ruptured Node Cladding Temperatures	RAI SNPB-16	Figure 16-10

2 The plots for Core Collapsed Liquid Level, Collapsed Liquid Level Lower Plenum, Core Quench Level, and Reactor Vessel Liquid Mass provide sufficient detail that this plot is no longer needed.

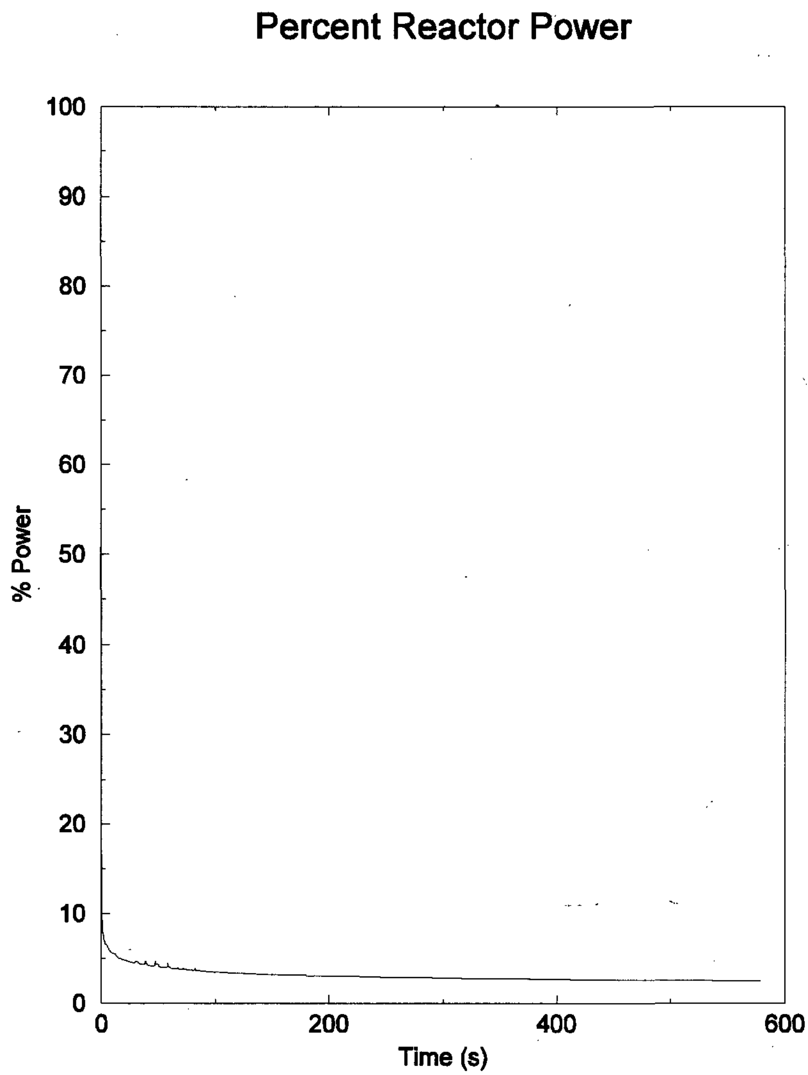

Figure 16-1: Normalized Power versus Time

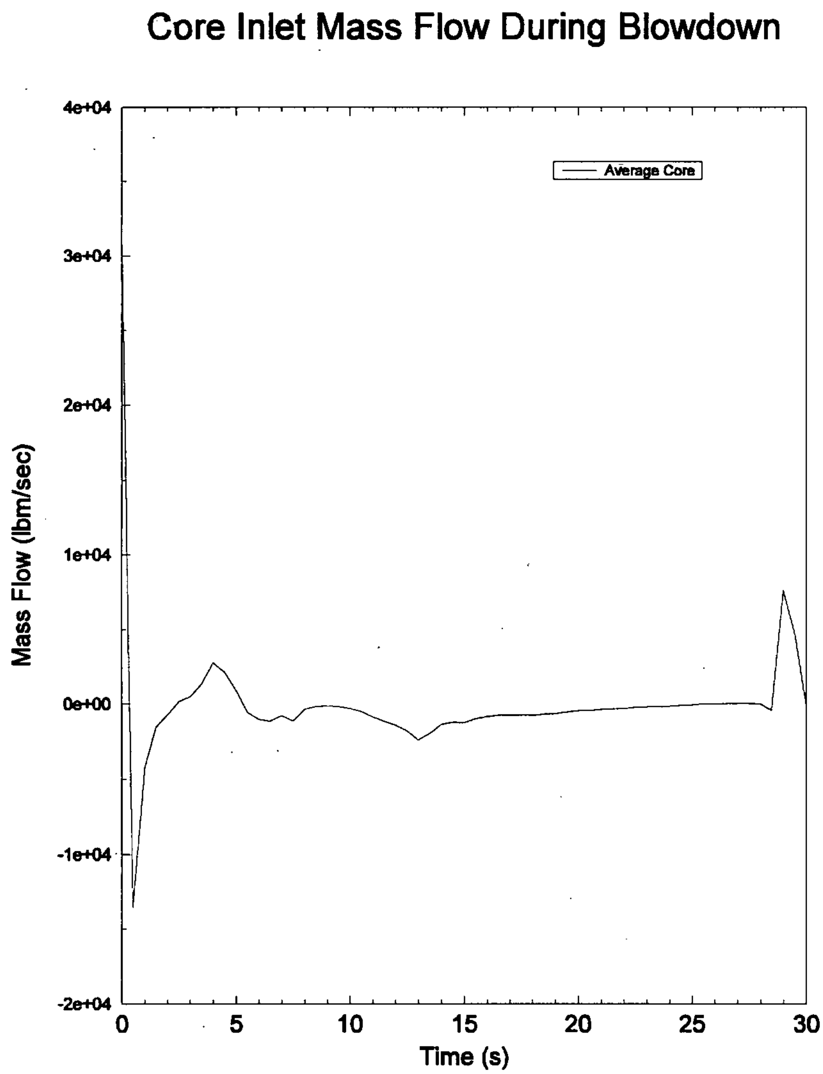

Figure 16-2: Average Core Inlet Flow Rate during Blowdown (EOB = 26.18 s)

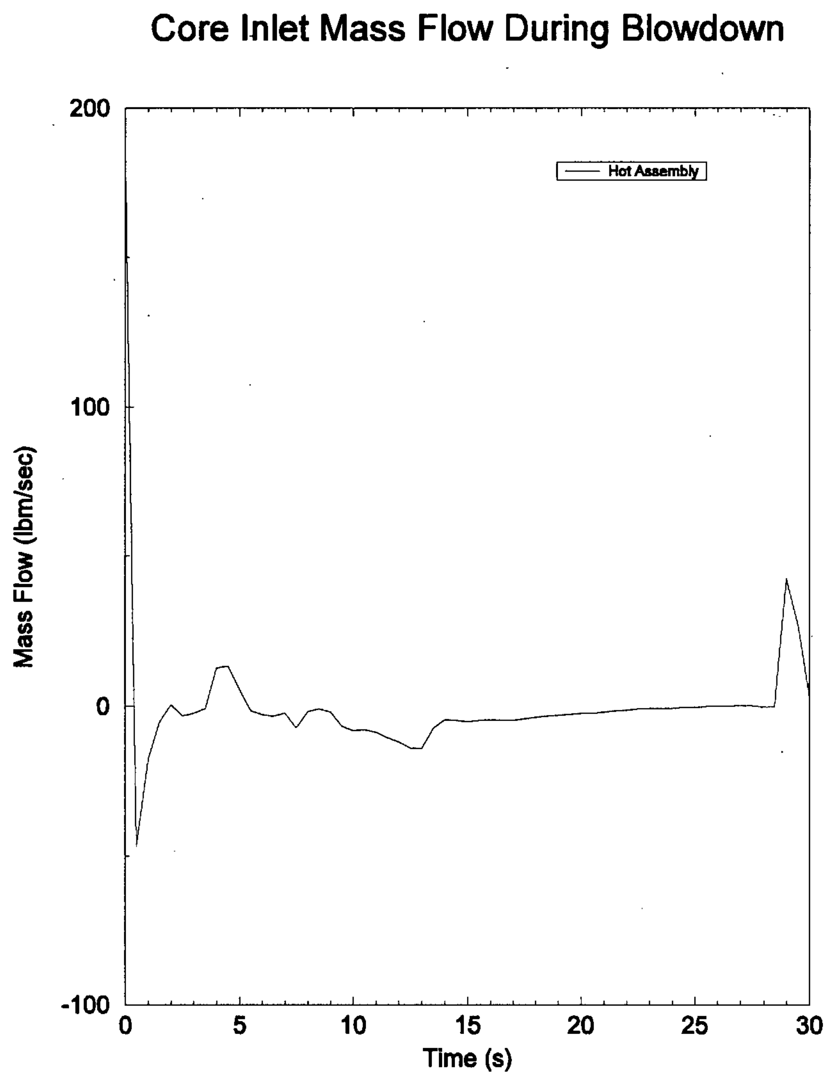

Figure 16-3: Hot Channel Inlet Flow Rate during Blowdown (EOB = 26.18 s)

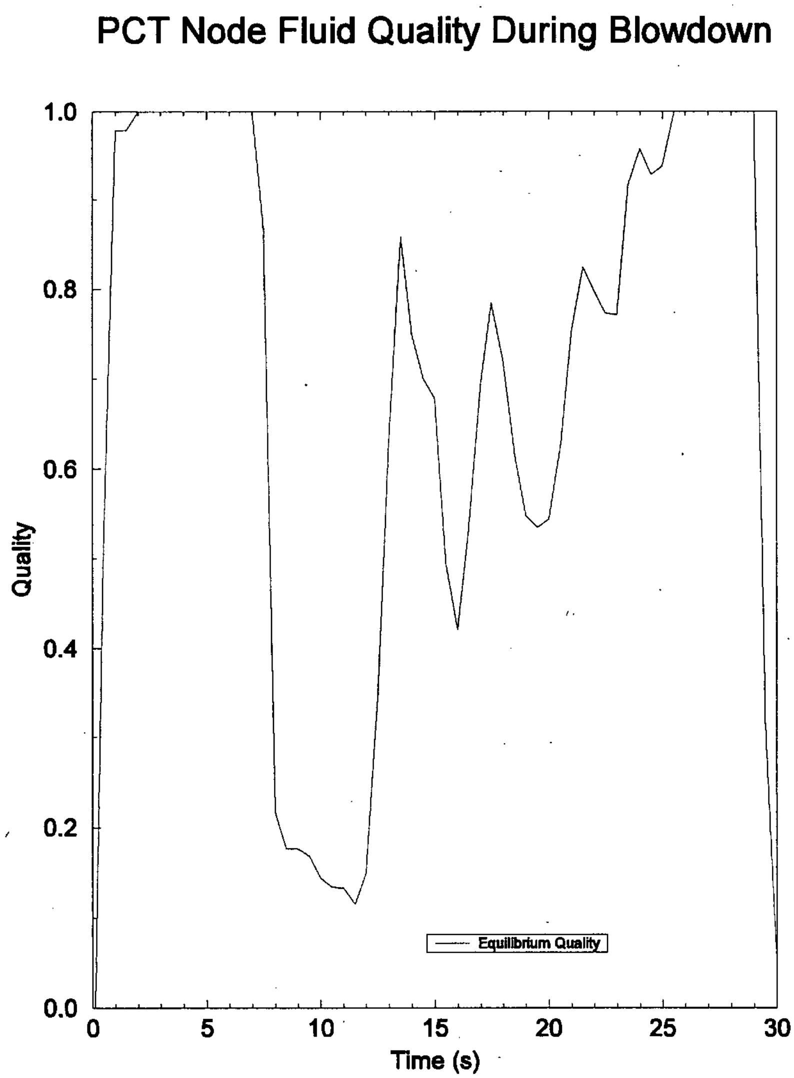

Figure 16-4: PCT Node Fluid Quality during Blowdown (EOB = 26.18 s)

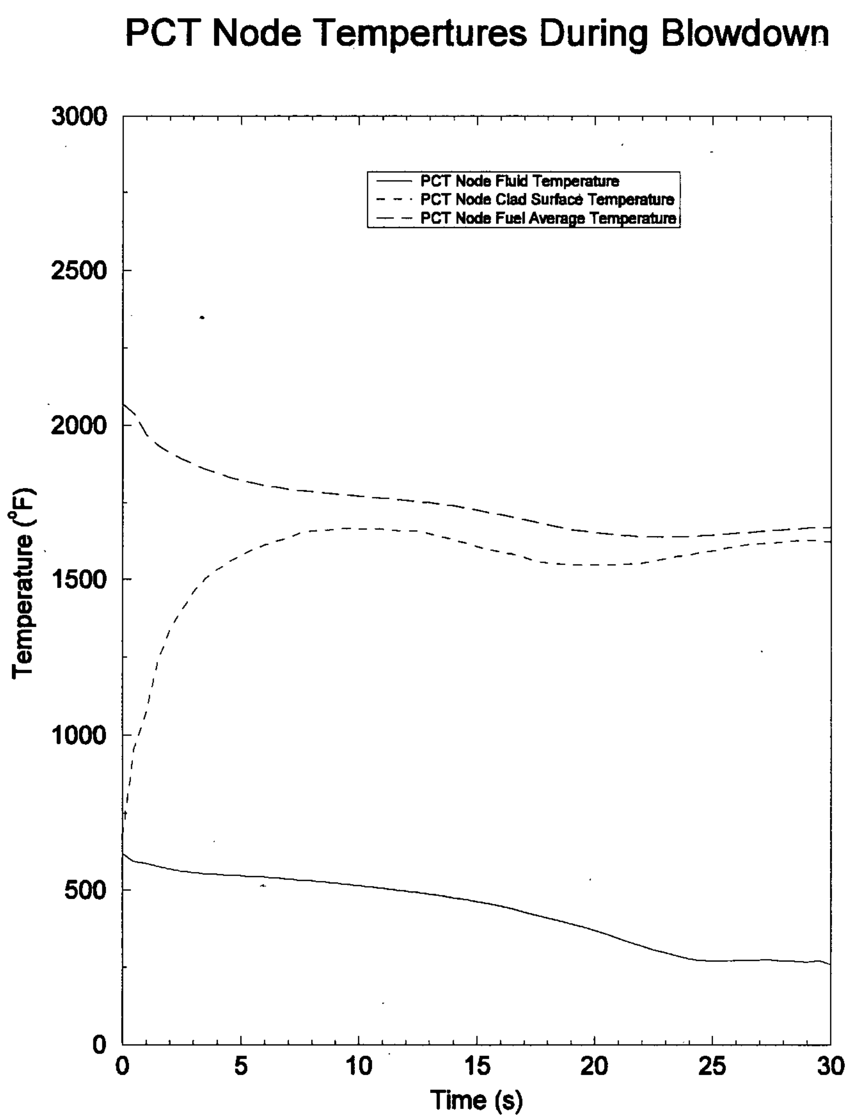

Figure 16-5: PCT Node Fuel (Average), Cladding and Fluid Temperatures during Blowdown (EOB = 26.18 s)

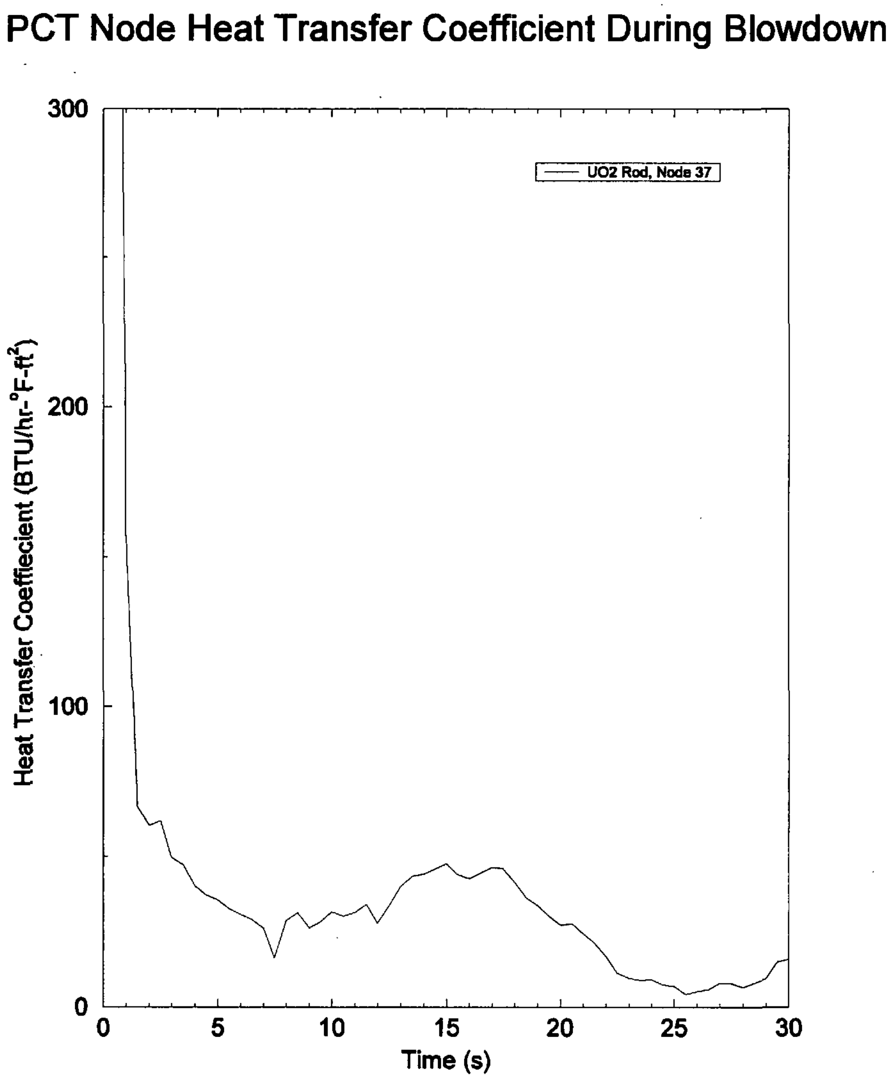

Figure 16-6: PCT Node Heat Transfer Coefficient during Blowdown (EOB = 26.18 s)

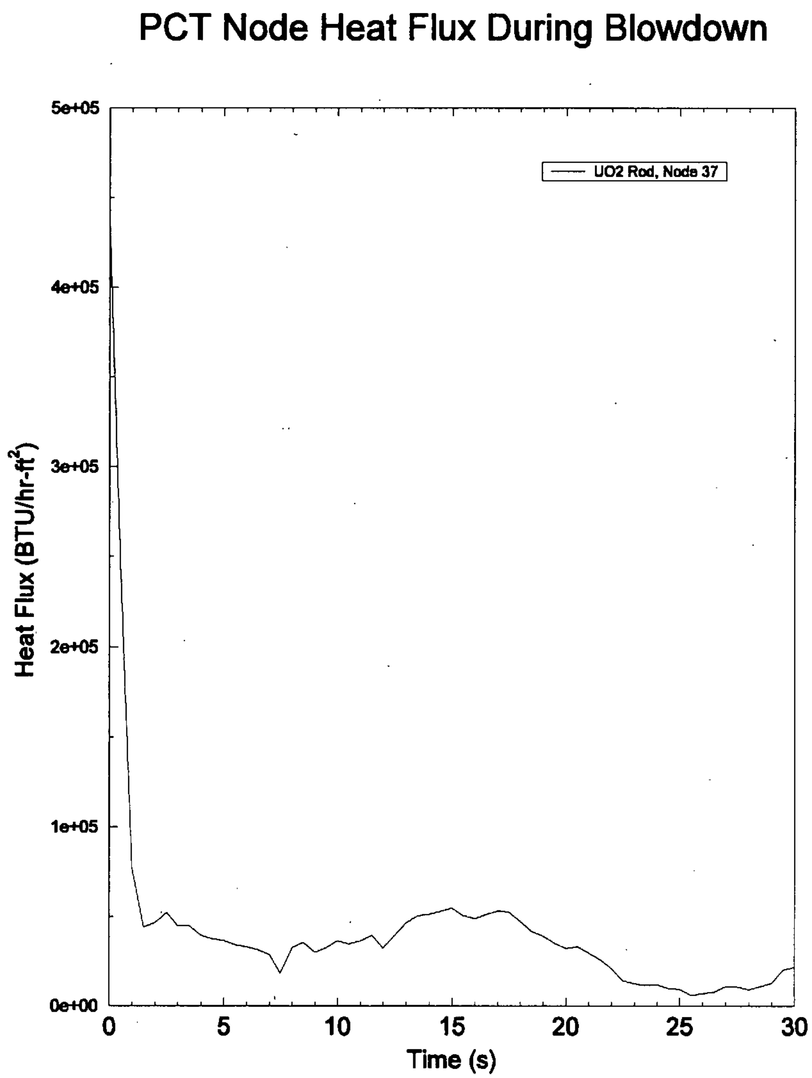

Figure 16-7: PCT Node Heat Flux during Blowdown (EOB = 26.18 s)

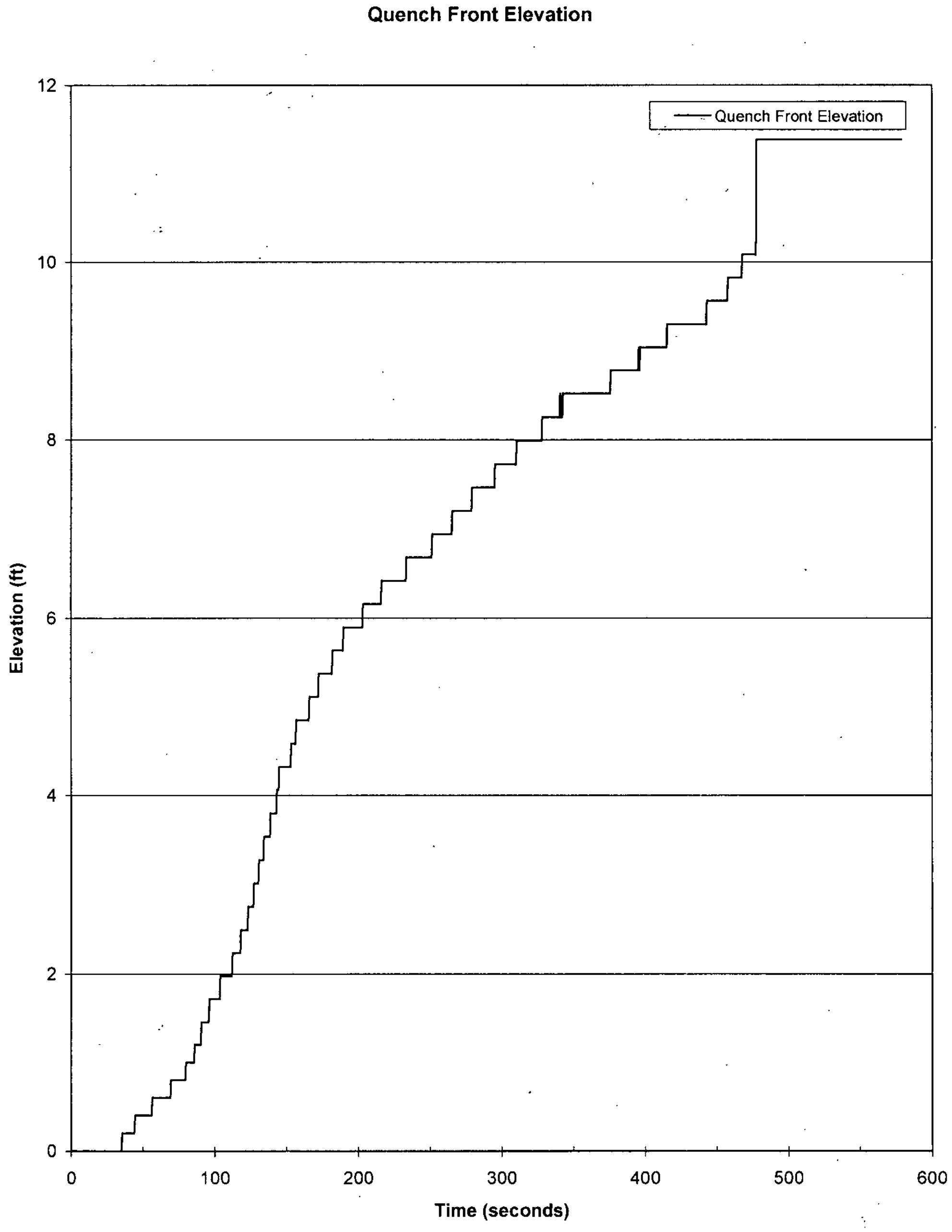

Figure 16-8: Core Quench Level

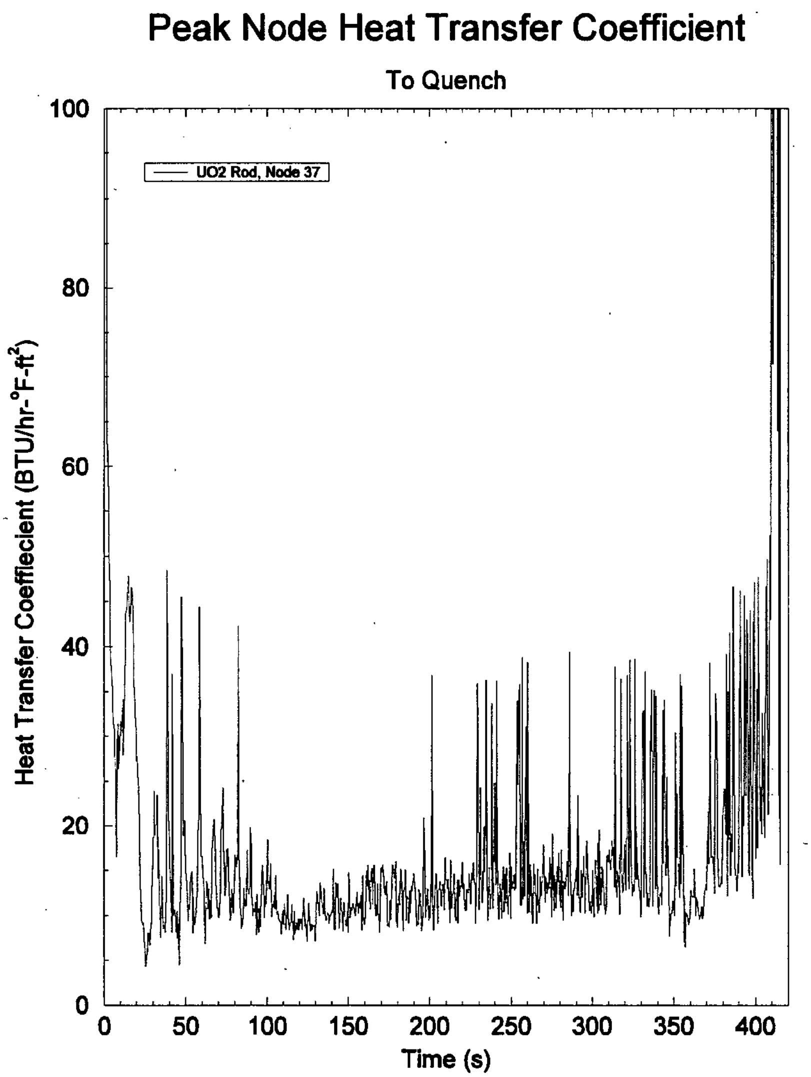

Figure 16-9: PCT Node Heat Transfer Coefficient, (To PCT Node Quench)

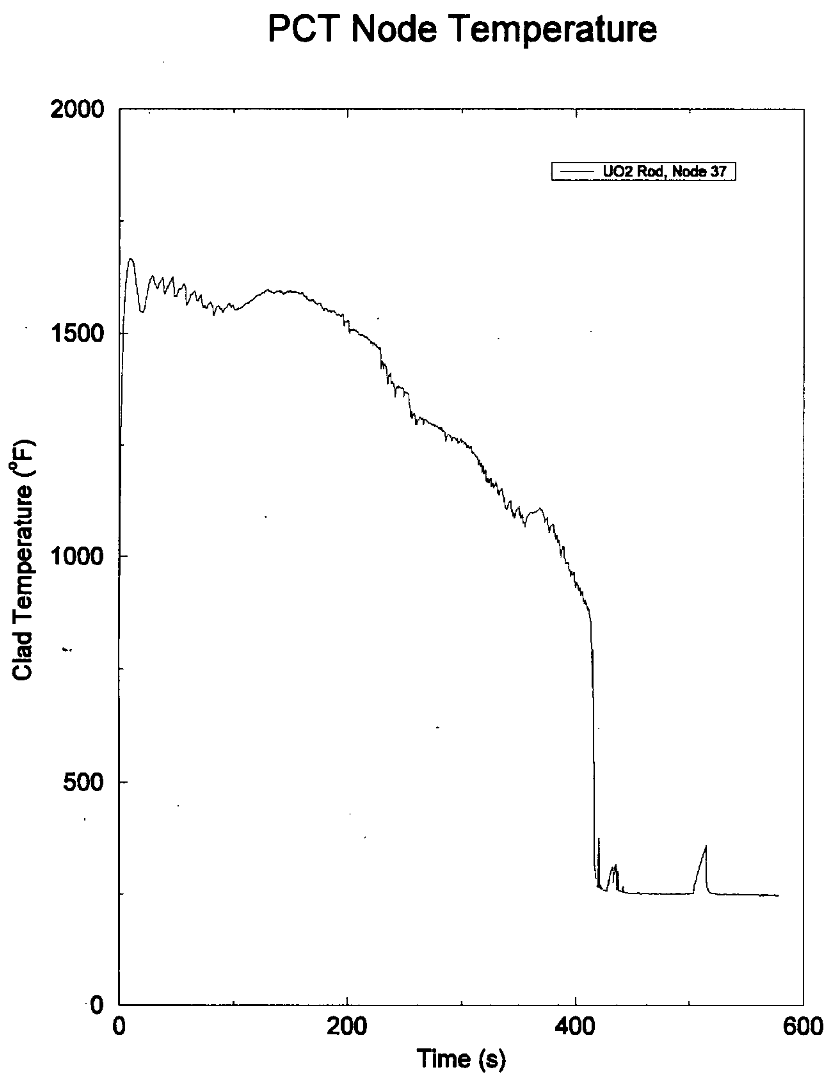

Figure 16-10: PCT Node Cladding Temperature