PDR

CP&L

Carolina Power & Light Company

OG-137
Ref: OG-110,
12/1/83 &
OG-117
3/9/.84
October 25, 1984

Mr. David Jaffe
U.S. Nuclear Regulator Commission
Phillips Bldg.
Washington, DC 20555

Westinghouse Owners Group
Program to Address Generic Letter 83-10 - RCP Trip
Response to NRC Questions

Dear Mr. Jaffe:

Enclosed is the Westinghouse Owners Group response to the NRC questions, received in NRCS-84-59, regarding our earlier submittals, referenced above.

Very truly yours,

J J Sheppard

J. J. Sheppard, Chairman
Westinghouse Owners Group

Enclosure

cc: WOG Reps
Analysis S/C

RD-8-2
W

411 Fayetteville Street • P. O. Box 1551 • Raleigh, N. C. 27602

Q.1 Describe what the utility procedures will be if none of the three alternate criteria will prevent pump trip for SGTRs and non-LOCAs for their plant.

A.1 Should none of the three alternate criteria provide the ability to discriminate between SBLOCAs, SGTRs and non-LOCA events, the recommendation would be to use the criterion which demonstrated the greatest discrimination capability. In doing so, a large range of SGTRs + non-LOCA events still would not require RCP trip. In the event of RCP trip occurring for SGTRs + non-LOCAs, the Emergency Response Guidelines (ERGs) provide specific contingency actions required to recover the plant even though RCP operation is not available. Also, specific RCP restart steps are built into the ERGs where deemed beneficial although they are not required for safe plant shutdown. It is expected, however, that at least one of the alternate criteria will be successful in preventing pump trip for SGTRs and non-LOCAs for each of the plants.

Q.2 For each plant group, which transient gives the minimum values supplied in Table 1?

Q.3 For the plants where the values are not from SGTRs, provide the corresponding values for SGTRs.

A.2-3 The minimum values of the RCP trip parameters for the SGTR transient are presented in Table 2 of Attachment 2 of reference 1 (pages 41-42), and the minimum values for the non-LOCA transients are presented in Table 2 of Attachment 3 of reference 1 (page 49). A comparison of Table 2 of Attachment 2 and Table 2 of Attachment 3 with Table 1 of the report shows that the SGTR transient gives the minimum values for all of the RCP trip parameters for all plant categories with the exception of the RCS pressure trip parameter for three plant categories. The three plant categories and the minimum values of the RCS pressure for each are listed below:

(1) For South Texas 1 and 2, the minimum value for the feedline break is 1559 psia, whereas the minimum value for the SGTR is 1607 psia.

(2) For Summer and Shearon Harris 1 and 2, the minimum value for the steamline break is 1436 psia, whereas the minimum value for the SGTR is 1543 psia.

(3) For Ginna and Point Beach, the minimum value for the steamline break is 1181 psia whereas the minimum value for the SGTR is 1199 psia.

Q.4 How soon are adverse containment conditions expected to occur for SBLOCAs with break sizes from the size of a PORV to the larger breaks considered in Refs. 1 and 2?

A.4 For RCP trip concerns, reaching adverse containment conditions would cause the operator to use the adverse containment condition RCP trip setpoint in conjunction with the Westinghouse Emergency Response Guidelines (ERGs). The adverse containment conditions would result in a higher RCP trip setpoint which will result in the operator taking earlier action to trip the RCPs. Requiring RCP trip early in the SBLOCA event has always been the Westinghouse procedural recommendation. It continues to be to avoid the potential worsening of SBLOCA transients due to continued inventory depletion. The actual timing of the onset of adverse containment conditions is not only plant system and containment-design specific, but also dependent on analysis assumptions. For the purpose of the reference WOG reports, a complete spectrum of SBLOCA sizes and locations have been analyzed assuming prompt RCP trip to demonstrate acceptable ECCS performance (WCAP-9600).

Q.5 What non-LOCAs events, if any, can result in adverse containment conditions with the resulting higher setpoint requirements?

A.5 The non-LOCA events which could potentially lead to adverse containment conditions are steamline or feedline breaks within containment.

Q.6 What happens if containment conditions switch from normal to adverse?

A.6 Revision 1 of the Emergency Response Guidelines (ERGs) contains setpoint values for both normal and adverse containment instrument inaccuracies. The need for adverse containment instrument inaccuracies is determined on a plant specific basis depending on the location of equipment. If the specific equipment transmitting devices are located inside containment, then adverse instrument inaccuracies would be applicable during adverse containment conditions. In the event of containment conditions switching from normal to adverse, the operator would then apply the appropriate setpoint at the time each step is executed. The use of adverse containment setpoints will be covered during operator training.

Q.7 How frequently does the operator evaluate containment conditions?

A.7 In those steps in the ERGs where both the normal and adverse containment setpoints are given, the operator decides which of the two values to use by checking the containment pressure and radiation conditions, at the time each step is executed. Definition of the normal and adverse containment conditions are provided in the Generic Issues Section of the Rev. 1 ERG Executive Volume under the Generic Instrumentation section.

Q.8 Describe how the SBLOCAs were modeled in Attachment 1 of Ref. 1 including noding diagrams for the system model.

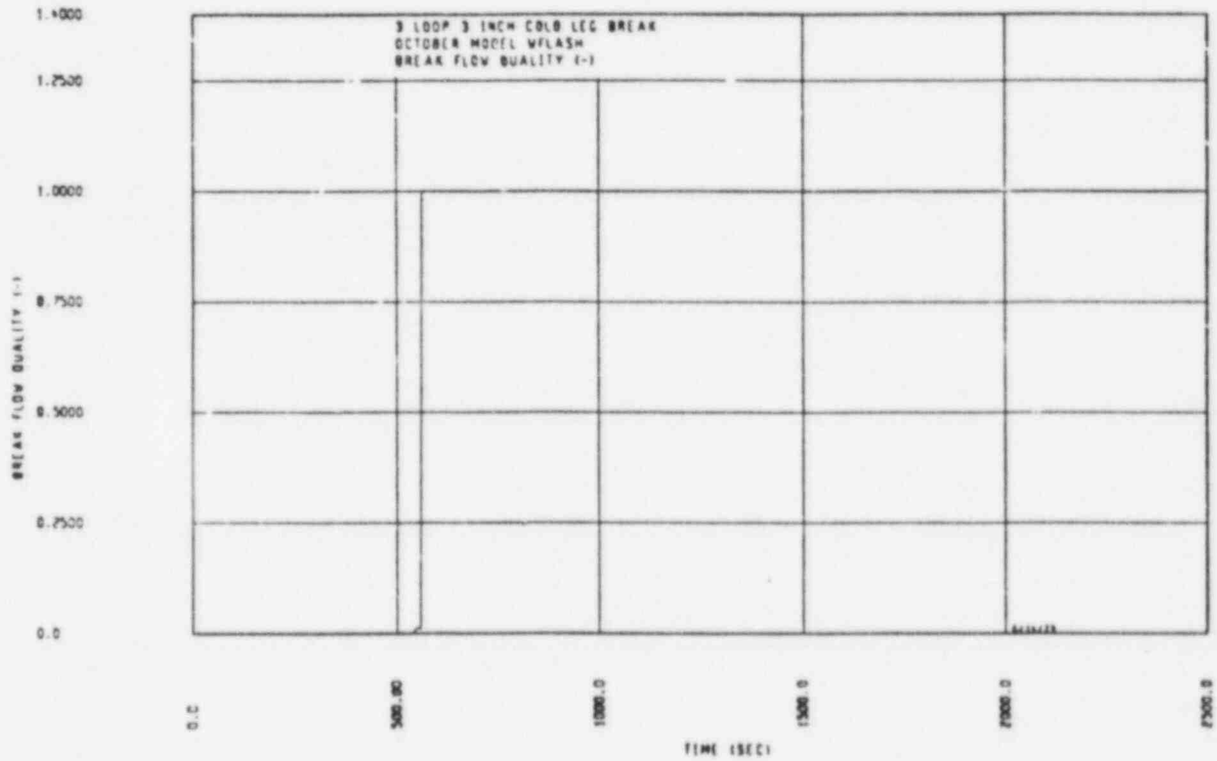
A.8 Detailed modeling descriptions were provided in WCAP-9584. The system noding diagram used is the same as presented in WCAP-8200 Rev. 2. Appendix A Figure A. The only exception to this model were the cases which used the revised accumulator model, details of which are provided in reference 2 Appendix A.

Q.9 Why is the break-flow quality nearly zero when the pumps are on rather than closer to the mixed quality of the system?

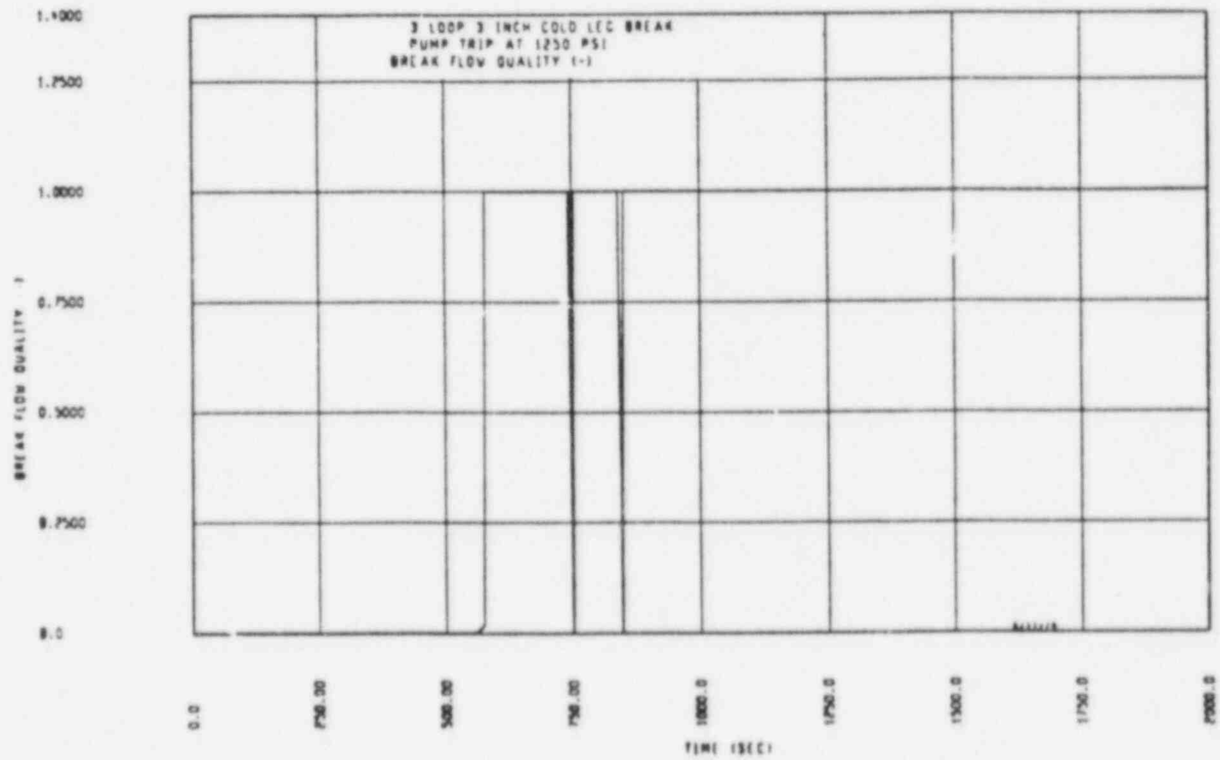
A.9 The break-flow quality is nearly zero even with RCPs on since the steam generators are removing heat generated by the core and therefore condensing steam. This can be verified by looking at the qualities for both the hot leg and cold leg for a typical transient with the RCPs operational. Also, refer to the response to question 60 for additional breakflow model details.

Q.10 Provide a plot of the quality or void fraction in the cold leg near the break as a function of time for the cases presented in Figure 1 on page 18 of Reference 1.

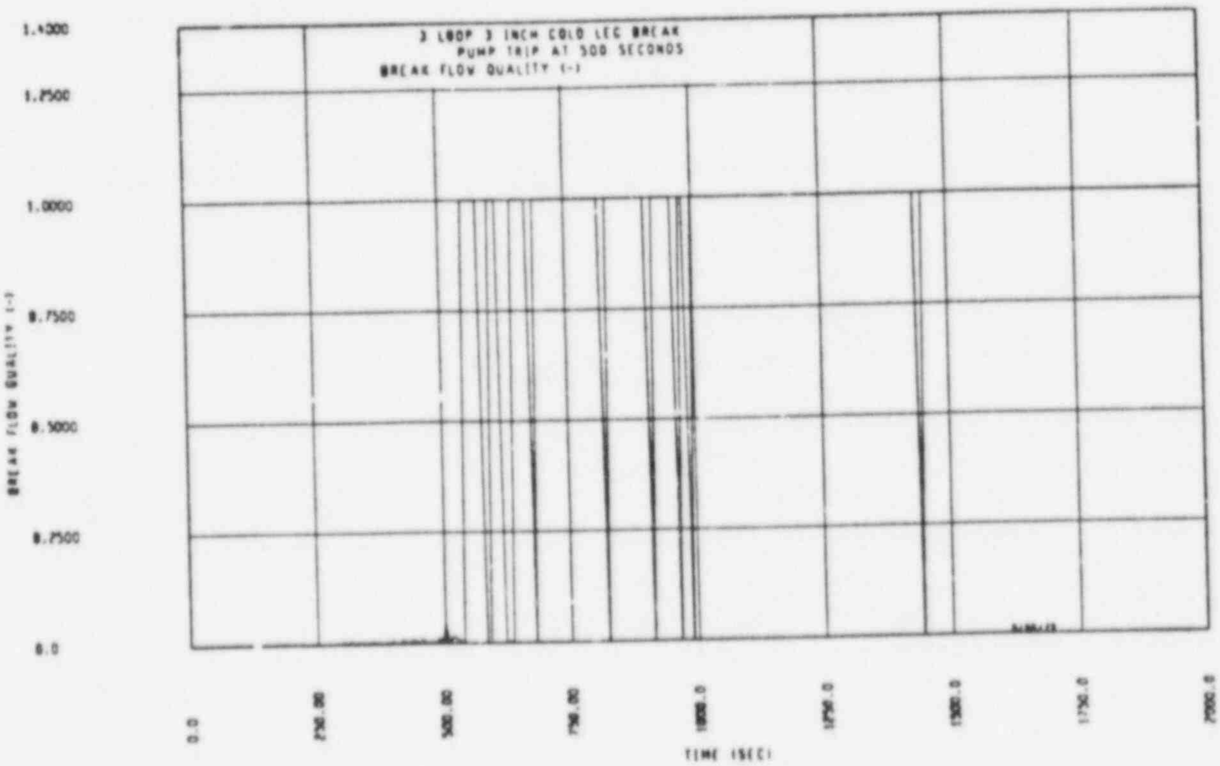
A.10 See the attached figures.



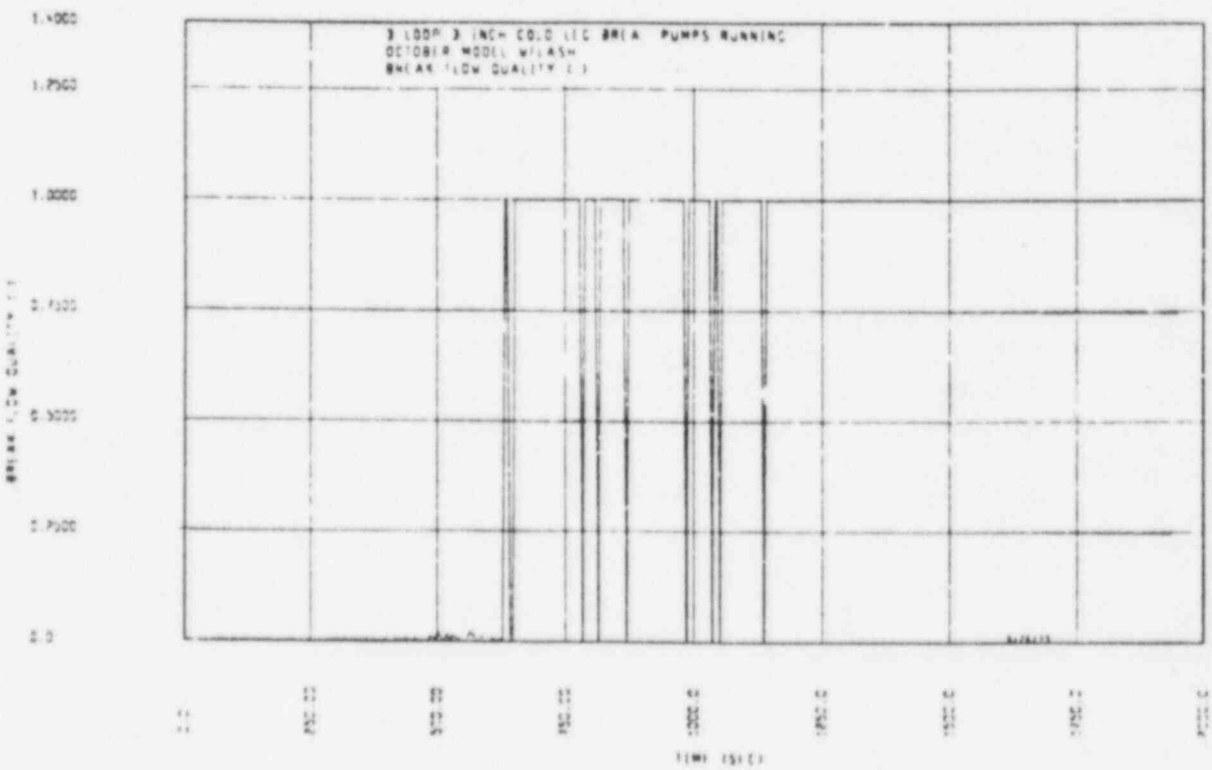
Break Flow Quality - RCP Trip at Scram Time - 22 SECONDS



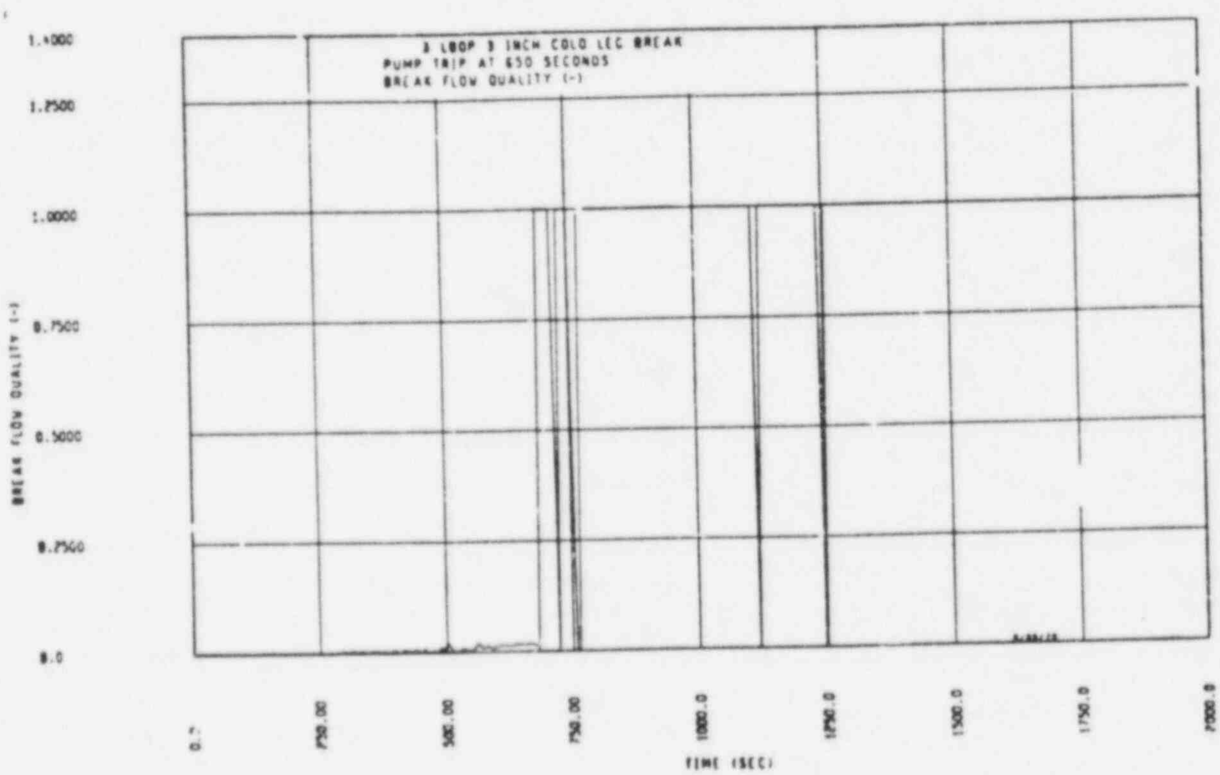
Break Flow Quality - RCP Trip At 74 SECONDS



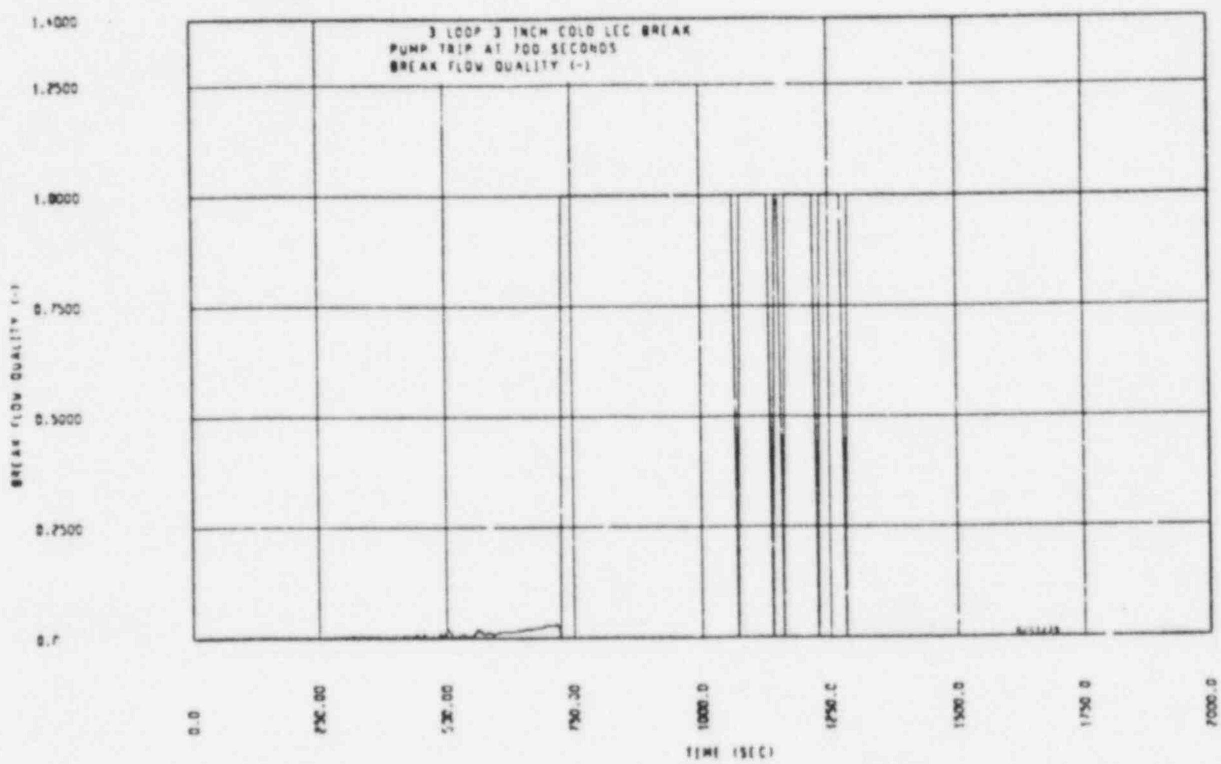
Break Flow Quality - RCP Trip At 500 SECONDS



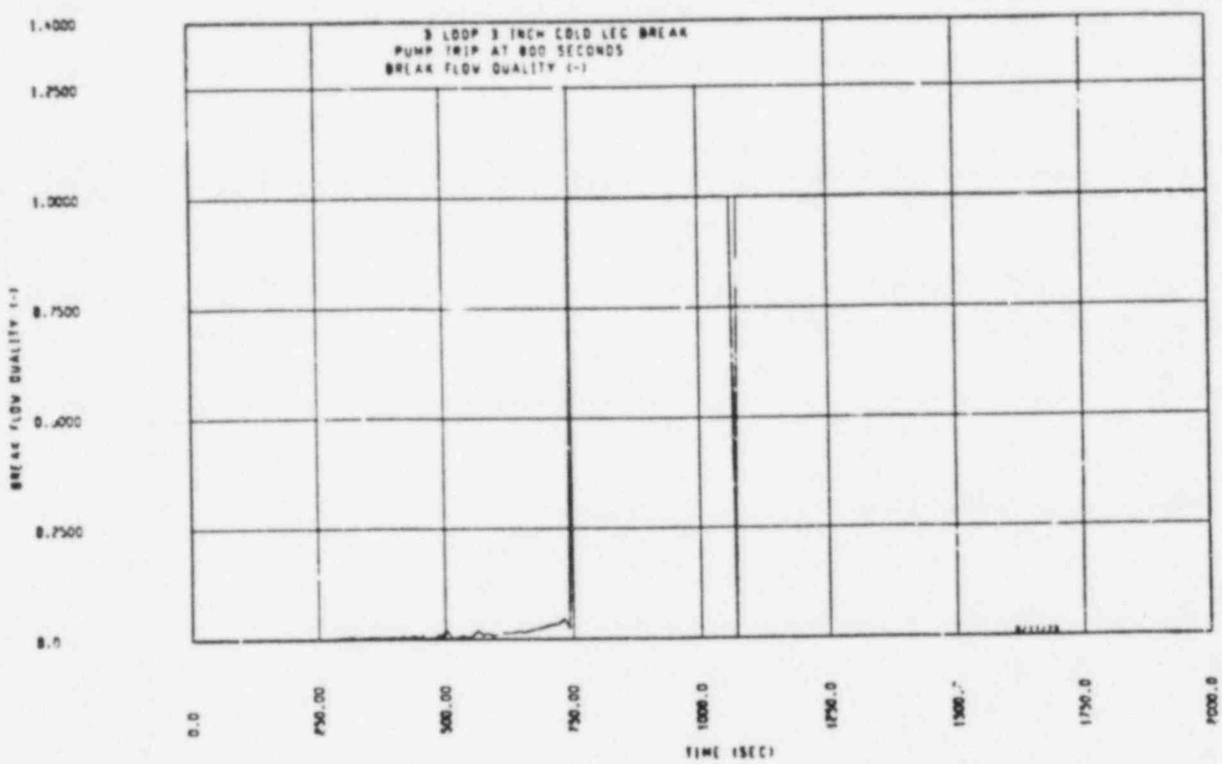
Break Flow Quality - RCP Trip At 575 SECONDS



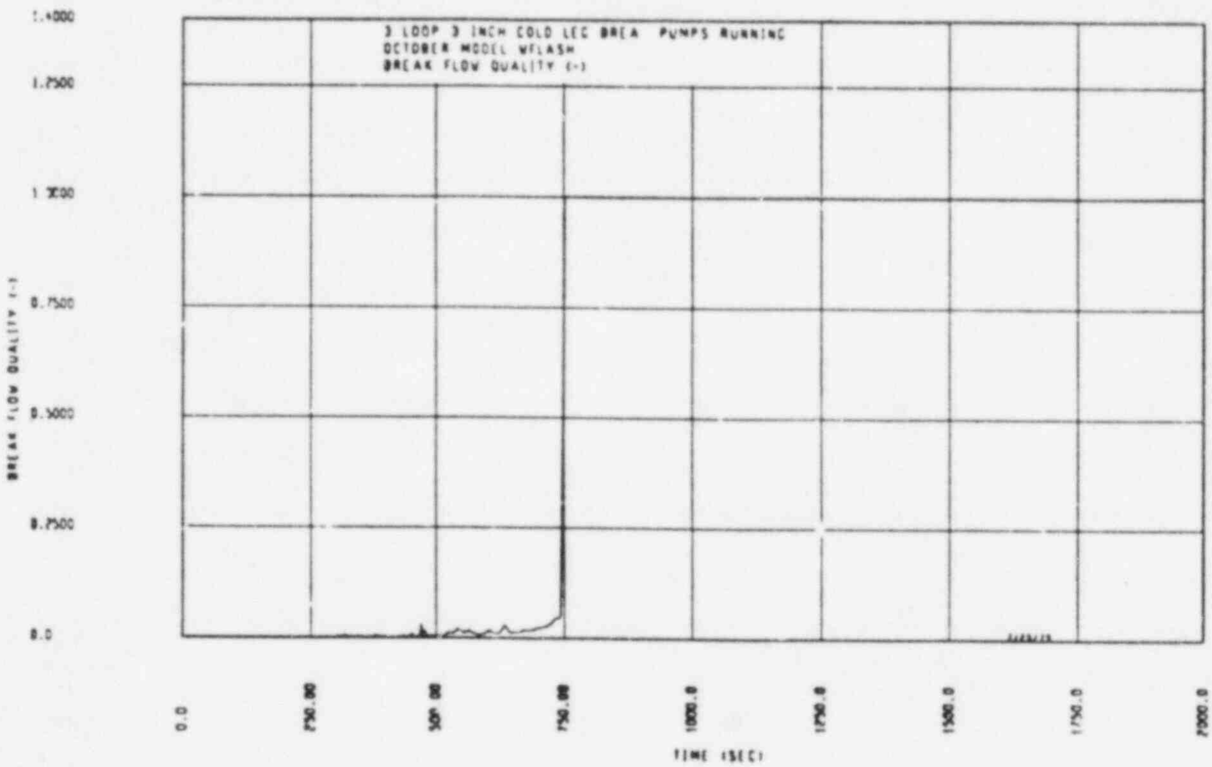
Break Flow Quality - RCP Trip At 650 SECONDS



Break Flow Quality - RCP Trip At 700 SECONDS



Break Flow Quality - RCP Trip At 800 SECONDS



Break Flow Quality - No RCP Trip During Transient

Q.11 What is the basis for the 6-in case because no information is given for 3-loop 6-in case in Ref. 1 or WCAP-9584?

A.11 This statement is based on the core uncovery history plot presented for the 4.5 inch transient case in Figure 5 of Reference 2. As can be seen by the figure, the core becomes completely uncovered for this transient, therefore, no deeper core uncovery can be predicted. Since the nature of larger break sizes (rapid depressurization and higher breakflow rates) tends to reduce the core uncovery period, the clad heatup period is shortened. Therefore, no higher clad temperature is expected to occur for a 6 inch diameter small break LOCA. Additional verification can be obtained by looking at existing FSAR small break results which demonstrate that 6-inch LOCAs are less limiting than smaller break sizes.

Q.12 How much does the plant primary-system volume vary between the vessel and the rest of the primary system for the different 2-, 3- and 4-loop plants?

A.12 For various 2, 3 and 4-LOOP plants, the plant primary system volumes vary as follows:

Plant	Plant Name	Vessel Delta	Loop Delta	Total Delta
CQL	Shearon Harris Unit 1		Base Plant	
APR	Farley Unit 1	96.4%	103.4%	100.5%
FPL	Turkey Point Unit 3	97.1%	103.5%	100.9%
NSP	Prairie Island Unit 1		Base Plant	
WEP	Point Beach Unit 1	99.6%	99.8%	99.7%
GAE	Vogtle Unit 1		Base Plant	
IPP	Indian Point Unit 2	101.2%	94.4%	97%
CWE	Zion Unit 1	100.7%	102.6%	101.9%
TGX	South Texas Unit 1	96.2%	118.3%	109.9%

Q.13 Provide the basis for the selection of the critical size range chosen for the 2, 3 and 4-loop plants?

A.13 Detailed discussion relating to the choice of the critical break size range is provided in WCAP-9584 pages 37-40.

Q.14 Why is only one size used for two loop plants?

A.14 Only one two-loop break size was analyzed since the calculated critical break size, based on WCAP-9584 results, would be less than 3 inches. Break sizes smaller than 3 inches would result in a less limiting critical RCP trip time than that presented for the 3 inch case. In addition, break sizes larger than 3 inches are not limiting since the 2-loop plant design allows for the additional benefit of accumulator injection at 715 psia. Therefore, break sizes greater than 3 inches are not important in this discussion of RCP trip criteria time for 2-loop plants.

Q.15 How much later would each of the trip setpoints be reached using best-estimate versus Appendix K models for the cases considered in this report?

A.15 The RCP trip setpoints would not be reached later for the best estimate model analysis, they in fact occur earlier because condenser steam dump results in a more rapid depressurization to a lower RCS pressure. Also, the available operator action time is extended due to the delay in critical inventory time occurrence due to reduced break flow which is a result of lower RCS pressure. A comparison of the time to the individual trip setpoints is shown below.

Analysis	RCS pressure	Subcooling	Pri/sec ΔP	Critical Inventory
Appendix K	53 s	55 s	90 s	500 s
Best Est.	34 s	34 s	50 s	930 s

As can be seen, the available operation action time to critical inventory is twice that of the Appendix K analysis.

Q.16 Are there any break sizes below which the best-estimate calculation would not indicate the trip setpoints were reached but the Appendix K models would indicate the trip setpoints were reached?

A.16 For a similar size break, the best-estimate analysis could equilibrate initially at a higher pressure due to the improved safety injection performance. SI would match break flow at a higher pressure potentially above the trip setpoint. The best-estimate case would eventually reach trip setpoint however, due to the availability of steam dump and lower decay heat values which would allow the plant to continue to cooldown and depressurize. Should the trip setpoint not be reached however, the plant would still be maintaining a safe stable condition since sufficient inventory and heat sinks would be available. For the break sizes of interest for SBLOCAs, the trip setpoint would be reached.

Q.17 Provide the basis for the 100 and 60 psi values used.

A.17 These values were used because they are representative of the values which would be used to establish the RCP trip setpoints for most plants. The setpoint using hot leg pressure is determined by adding the secondary relief valve setting plus a 3% accumulation allowance and the calculated pressure differential from the secondary relief valve to the hot leg pressure measurement location. The sum of the 3% accumulation allowance and the calculated pressure differential is typically approximately 100 psi for most plants. The primary/secondary ΔP setpoint is equivalent to the calculated pressure differential from the steamline pressure measurement location to the hot leg pressure measurement location, which is typically approximately 60 psi. Note that the comparable values which were calcuated for the sample plant in Attachment 4 of Reference 1 are 91 and 59 psi.

Q.18 How sensitive is the timing of events to the initial conditions, and in particular which initial condition variations are most important?

A.18 The conditions which are of primary importance are those parameters which will model the individual plant operating conditions, mainly, hot and cold leg temperatures, steam generator secondary side temperatures and primary and secondary side pressures. By modeling to resemble plant operating conditions, the timing for achieving the RCP trip setpoints are not altered. In order to significantly alter the timing of events, a fairly large deviation from actual plant conditions would be required. Minor discrepancies in these values would alter timing in the order of seconds and not result in major changes. As an example, two identical plants were modeled, one plant assumed a value for T_{hot} of 585°F while the other assumed 578°F. The impact of this initial difference of 7°F in the initial T_{hot} value, based on the subcooling RCP trip setpoint, resulted in the RCP trip setpoint being reached 5 seconds sooner (RCP trip was predicted at 55 and 50 seconds, respectively). This demonstrates the impact of event timing due to initial condition differences, specifically, the time to trip RCPs via the subcooling setpoint.

Q.19 Clarify why for table 2 on pg. 27 of Ref. 1 cases 3B and 3C were not also run with 4.5-in breaks as was done with case 3A.

A.19 The purpose of these runs was to determine the minimum operator action time available in the event of a SBLOCA. As can be seen from the results of table 2 on page 27 of reference 1, the critical inventory times presented for the 3-loop plants demonstrate that cases 3B and 3C have equal or less limiting critical operator action times than similar 3A cases. Since the intent of this analysis was not to look at every break size for every plant, the results presented in the table provide bounding type conservative analyses and additional runs were deemed not be appropriate or necessary.

Q.20 Describe what noding was used to model the system for the SGTR.

A.20 The SGTR transients were analyzed with the LOFTRAN program. The noding used in the LOFTRAN program is described in WCAP-7907-P-A, "LOFTRAN Code Description," April, 1984, (Proprietary Class II).

Q.21 Are there any design-basis or smaller SGTR cases which will not result in the pumps remaining on?

A.21 It is expected that the analysis results will be bounding for most SGTR events based on the design basis accident assumptions used for the analysis and the conservatisms in the analytical model. However, it is possible that design basis or slightly smaller sized SGTR cases could occur which would result in RCP trip if the conditions associated with the SGTR are more limiting than those assumed for the analysis. For instance, if the SI flow is degraded significantly from the best estimate values used for the SGTR analysis, this would result in a lower RCS pressure which could result in RCP trip. However, it is expected that the results of this best estimate study will provide for continued RCP operation for most of the SGTR events which may occur.

Q.22 How much difference does the use of a conservative versus best-estimate break-flow model make in system conditions?

A.22 The use of a best-estimate break flow model for the SGTR analysis instead of the conservative model incorporated in the LOFTRAN program would result in a reduction in the break flow rate and consequently would yield higher primary system minimum pressures. Thus, the use of the conservative break flow model produces conservative results for use in establishing RCP trip parameters to prevent RCP trip for a SGTR. With a reduced break flow rate, the SI flow required to match break flow will also be reduced, which will result in a higher equilibrium pressure. The magnitude of this increase in RCS pressure would be dependent upon the SI system head flow characteristics.

Q.23 What break-flow model was used?

A.23 The double-ended SGTR is represented by an effective break area connecting the steam generator plenum to the secondary side of the steam generator. The critical flow through the break is calculated using a modified Zaloudek correlation. For non-critical flow, the orifice break flow model is used.

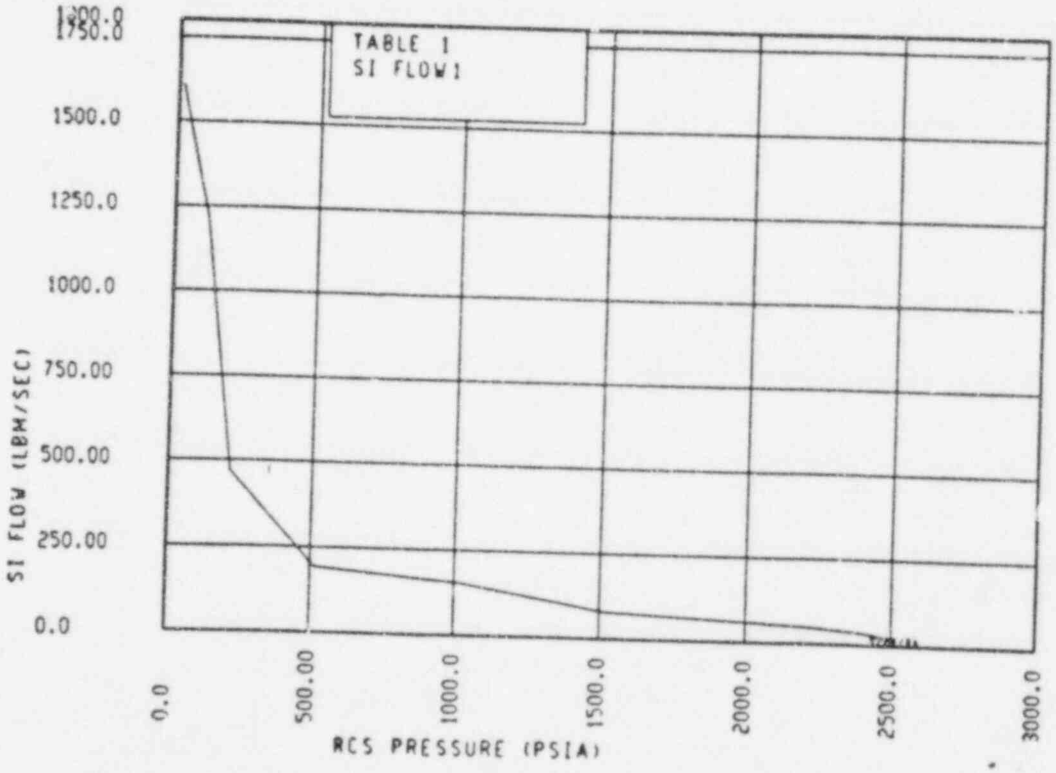
Q.24 What SI flow rates were used for each category?

Q.25 What auxiliary feedwater flow rate was used and was one selected for each grouping of 4-, 3-, and 2-loop plants or was the same one used for all of them?

A.24-25 The SI flow rates and auxiliary flow rates used in the SGTR analysis are shown for each plant category in Tables 1 through 8.

<u>Table 1</u>

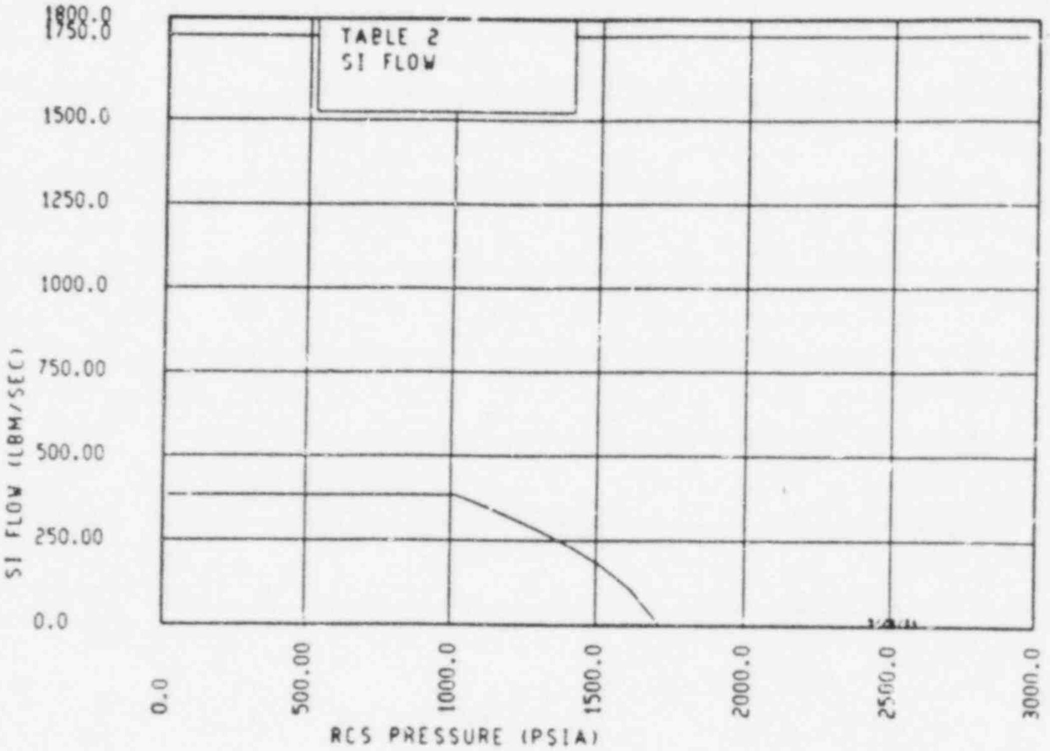
Vogtle 1 and 2	Trojan
Seabrook 1 and 2	Cook 1 and 2
Millstone 3	Zion 1 and 2
Snupps 1 and 2	
	Diablo Canyon 1 and 2
Byron 1 and 2	Salem 1 and 2
Braidwood 1 and 2	Sequoyah 1 and 2
McGuire 1 and 2	
Catawba 1 and 2	
Marble Hill 1 and 2	
Watts Bar 1 and 2	
Comanche Peak 1 and 2	



Auxiliary Feedwater Flow = 1880 gpm

Table 2

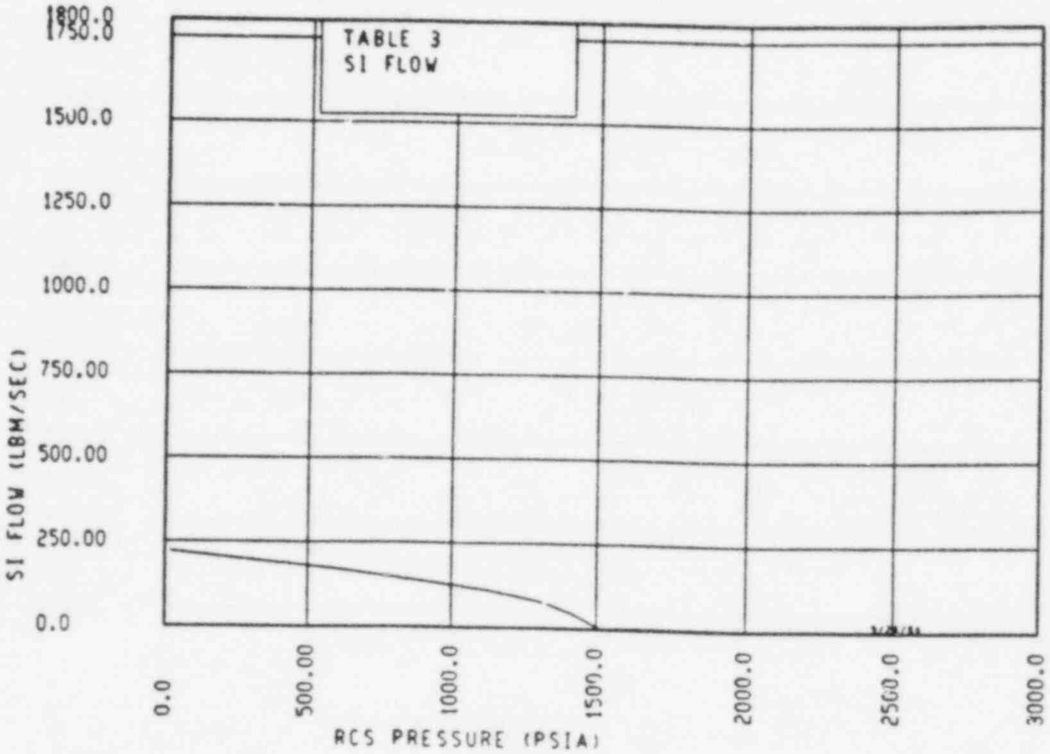
South Texas 1 and 2



Auxiliary Feedwat r Flow = 1880 gpm

Table 3

Indian Point 2 and 3



Auxiliary Feedwater Flow = 1880 gpm

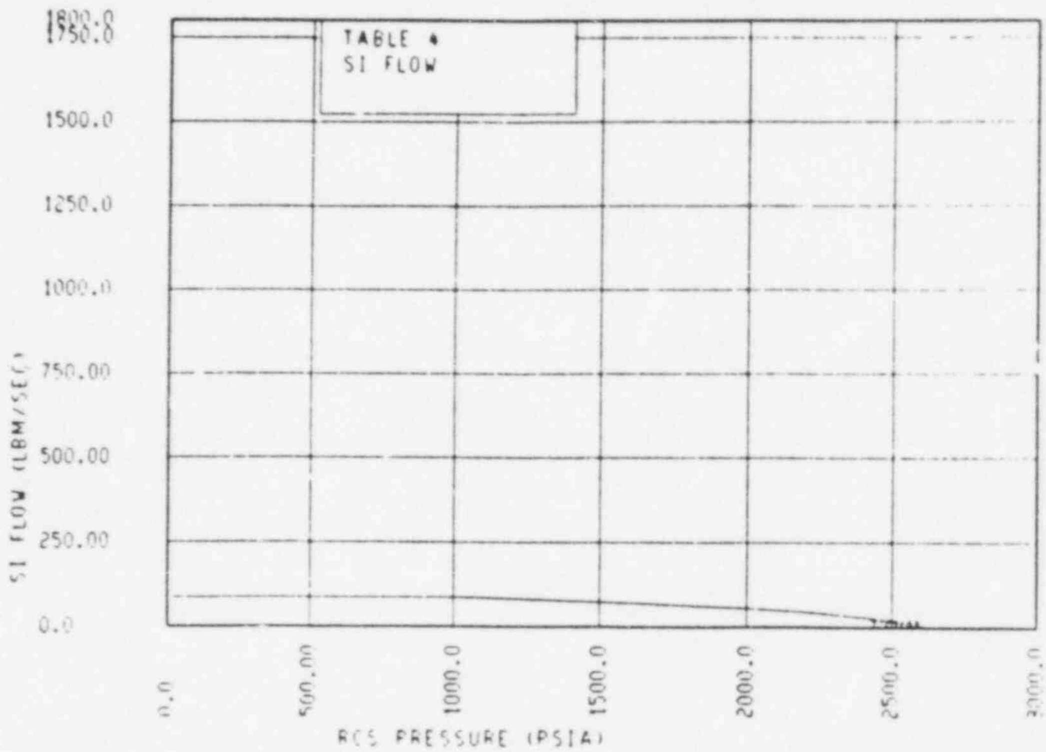
Table 4

Farley 1 and 2

North Anna 1 and 2

Surry 1 and 2

Beaver Valley 1



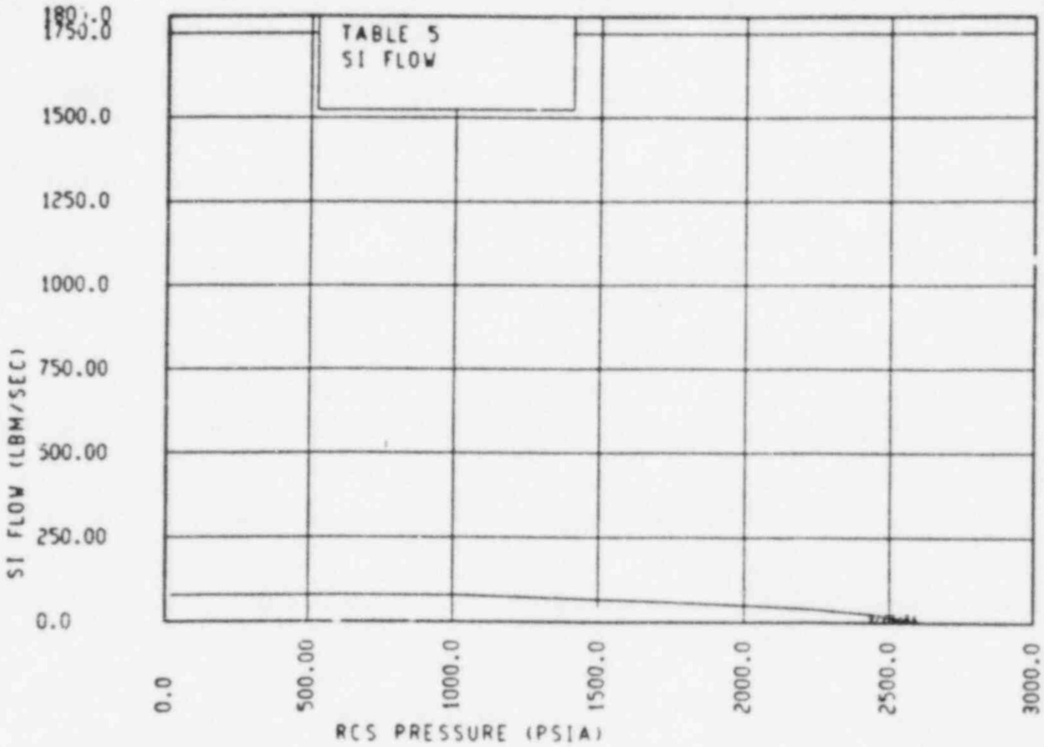
Auxiliary Feedwater Flow = 1400 gpm

Table 5

Summer

Shearon Harris 1 and 2

Beaver Valley 2

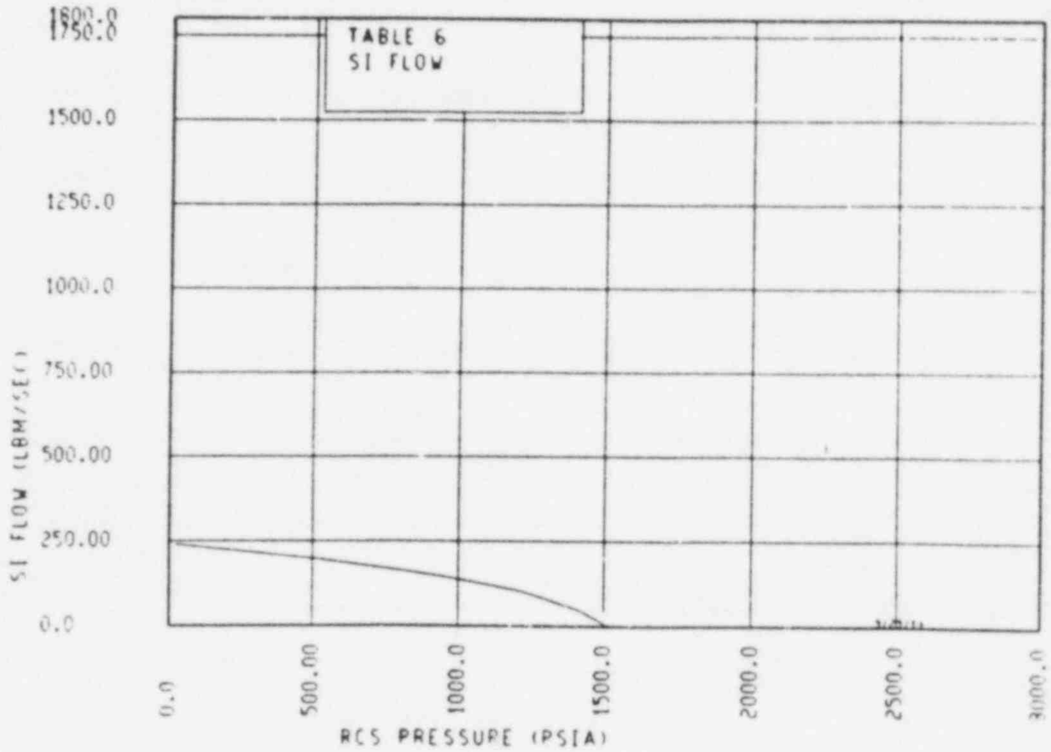


Auxiliary Feed flow = 1520 gpm

Table 6

Robinson

Turkey Point 3 and 4

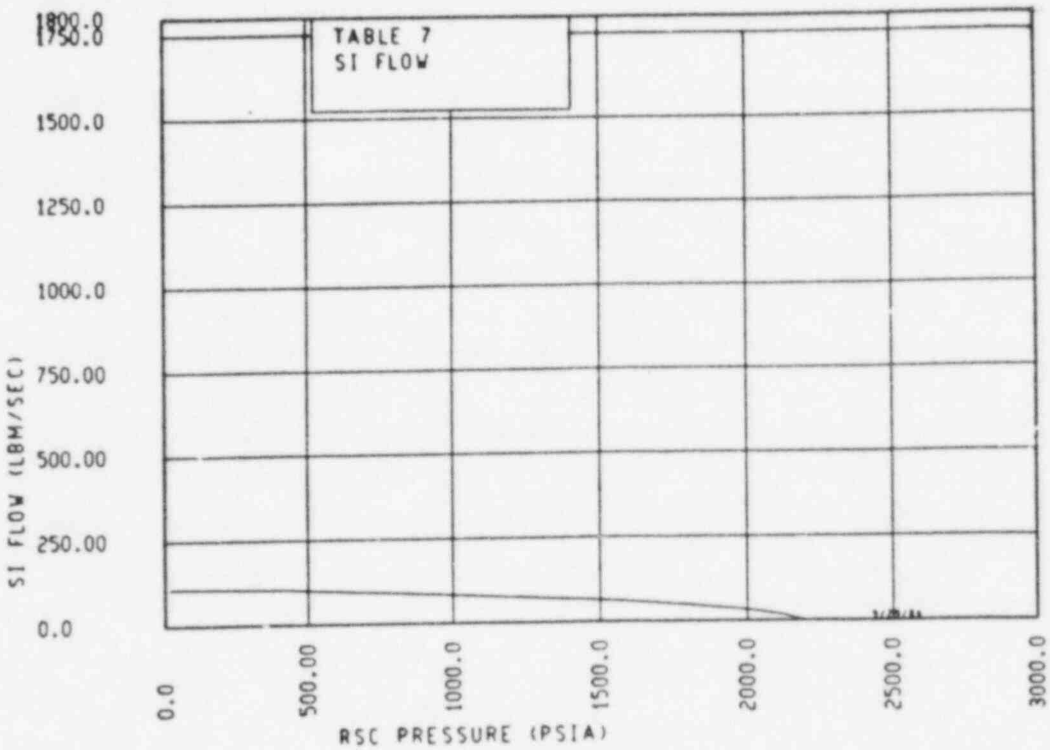


Auxiliary Feedwater Flow = 1200 gpm

<u>Table 7</u>

Prairie Island 1 and 2

Kewaunee



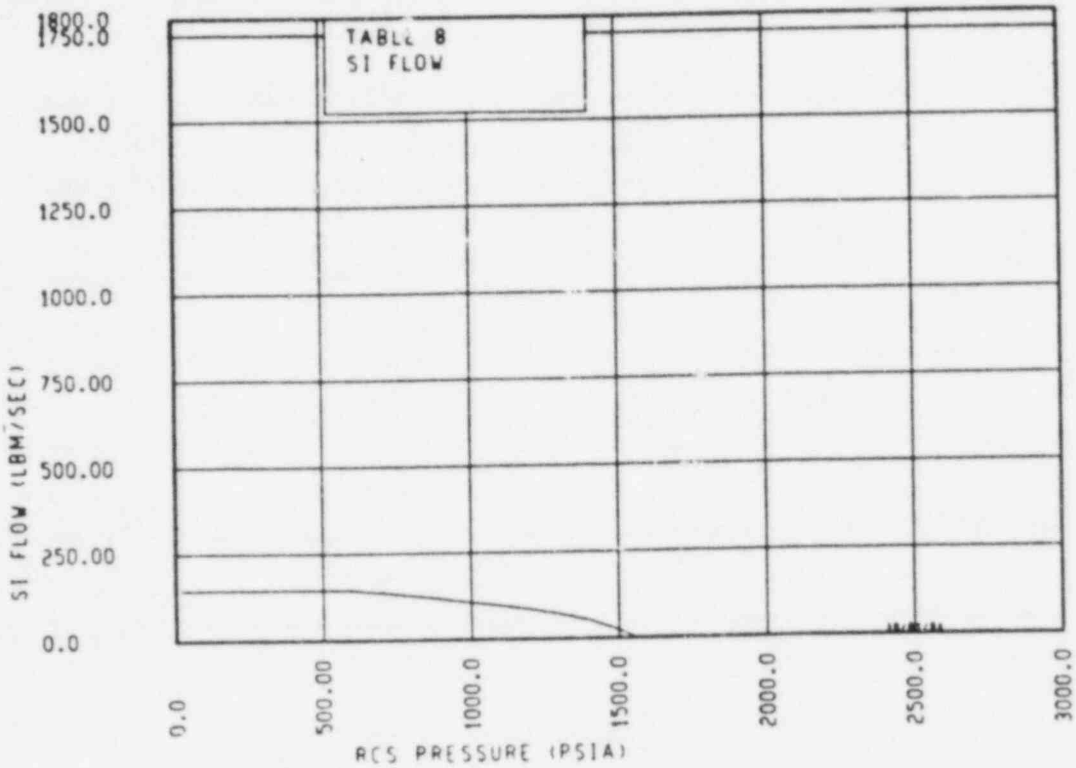
Auxiliary Feedwater Flow = 440 gpm (Prairie Island 1 and 2)

720 gpm (Kewaunee)

Table 8

Ginna

Point Beach 1 and 2



Auxiliary Feedwater Flow = 800 gpm

Q.26 Provide the justification as to why these conditions produce the limiting transient.

A.26 Following a SGTR, the operation of the steam dump sytsem will reduce the RCS temperature to the no-load value. For plants with higher T_{ave} values, this will result in a larger change in the RCS temperature which also results in more shrinkage of the reactor coolant. The increased shrinkage of the reactor coolant will result in a lower RCS pressure and also lower values of the other RCP trip parameters. The plants with the lower power levels will have lower decay heat levels which will result in less heat addition to the reactor coolant and a greater cooldown rate due to the operation of the SI and AFW systems. This will result in additional shrinkage of the coolant and generally lower values of the RCP trip parameters. Thus, the plants with higher operating T_{ave} values and the lowest power levels produce the limiting transients.

Q.27 Where and when does pressurizer emptying occurs in Figure 1 of Ref. 1 for Cases 2 and 3?

A.27 For case 2, the pressurizer empties at 315 seconds at which time the RCS pressure is approximately 1540 psia. For case 3, the pressurizer empties at 115 seconds at which time the RCS pressure is approximately 1600 psia.

Q.28 What causes the rapid decrease in the RCS pressure when the pressurizer empties?

A.28 Initially, the water in the pressurizer is saturated at the plant operating pressure of 2250 psia. Following a SGTR, the pressurizer level and RCS pressure decrease due to the coolant inventory loss through the rupture. As the water level in the pressurizer decreases and the pressure is reduced, flashing of the water occurs which tends to retard the rate of the pressure decrease. However, once the pressurizer empties, the temperature of the water surface in contact with the pressurizer steam space is reduced to that in the RCS hot legs. Since the water in the hot legs is subcooled, the flashing is restricted and the steam drawn from the pressurizer will condense in the hot leg, which causes the pressure decreases more rapidly. Note that the RCS pressure does tend to stabilize when the SI flow matches the break flow and that subcooling in the RCS is maintained throughout the transient.

Q.29 What factors are important in the relative rate of change of the RCS pressure and temperature and how much would they have to change for subcooling to continue to decrease?

A.29 After reactor trip, the RCS subcooling generally decreases with RCS pressure until the RCS pressure tends to stabilize at the point where the SI flow approximately equals break flow. The RCS temperature continues to decrease slowly after that time as a result of the net heat removal due to the continued SI and break flow and the continued operation of the auxiliary feedwater system. The RCS pressure will also continue to decrease slowly due to coolant shrinkage as the temperature decreases. However, as the RCS pressure decreases, the SI flow will increase slightly which will tend to maintain the pressure and reduce the rate of the pressure decrease. If the RCS temperature decreases faster than the pressure, the subcooling will increase, but if the pressure decreases faster than the temperature, the subcooling will decrease. It is noted that if the pressurizer does not empty, the temperature will decrease faster than the pressure; but if the pressurizer empties, the pressure will decrease faster than the temperature. Thus, the relative rate of change of the RCS pressure and temperature is dependent upon the status of the pressurizer level, and also upon the SI system pressure-flow characteristics, auxiliary feedwater flow rate, and decay heat level. However, the rate of change in subcooling due to the above effects is relatively slow. It is noted that even if the subcooling continues to decrease, the minimum value which occurs after reactor trip during the 10 minute transient which was analyzed has been used for the RCP trip parameter evaluation.

Q.30 If the minimum subcooling before reactor trip is not counted, what other reason explains the differences?

A.30 The minimum subcooling before reactor trip is not counted, which explains the differences that were noted in the results. The minimum subcooling for the referenced cases does occur just prior to reactor trip. However, the minimum subcooling prior to reactor trip is not used to evaluate RCP trip because the requirements for RCP trip are addressed in the Emergency Operating Procedures (EOPs), and the EOPs are not utilized until after reactor trip.

Q.31 Provide the tube rupture flows as a function of time for the different cases given.

A.31 Tube rupture flows as a function of time for each of the different cases were provided in Westinghouse letter NS-EPR-2918 (Ref. 3).

Q.32 How much is the system flow rate reduced to account for auxiliary spilling through the break?

A.32 The auxiliary feedwater (AFW) flow assumed in the feedline break analysis is comparable to approximately one motor driven AFW pump design flowrate for each plant classification. There is no significant sensitivity to the AFW flowrate however, since the limiting points occur during the initial blowdown of the steam generators.

Q.33 What does realistic reverse heat transfer mean as compared to any other assumptions normally used?

A.33 The realistic reverse heat transfer is used to differentiate between the two extremes used in the Chapter 15 safety analyses. LOFTRAN options typically used are:

1. No Reverse Heat Transfer - "No reverse heat transfer" allows normal forward heat transfer from the primary to the secondary sides of the steam generator U-tubes. Reverse heat transfer is not allowed even if a temperature difference exists where the S.G. secondary side is hotter than the primary side of the U-tubes. This maximizes the effects of an RCS cooldown.

2. Maximum Reverse Heat Transfer - "Maximum reverse heat transfer" results from LOFTRAN's calculation of heat transfer from the secondary side to the primary side of the steam generator tubes. The heat transfer is assumed to be uniformly distributed from the secondary side of the steam generator which maximizes the heat transfer to the primary system.

It is assumed that following steamline isolation, the recirculation in the steam generator is essentially non-existant. This may result in a temperature stratification on the secondary side of the steam generator where heat transfer occurs to/from the water in the steam generator tube bundle area.

This analysis uses a fraction of the LOFTRAN calculated heat transfer. This combines the effects of reverse heat transfer but limits the effect for the temperature stratification within the steam generator.

Page 48 of Ref. 1 states: "Reactor trip normally occurs on over-temperature ΔT or low pressurizer pressure for steamline breaks. In cases where the "credible" break does not result in a reactor trip for nominal setpoints, a reactor trip is imposed for the evaluation of the applicable parameters.

Q.34 What is the operator expected to do if the reactor trip did not occur for nominal setpoints?

A.34 The operator does not monitor for the need for RCP trip unless a reactor trip has occurred. A reactor trip was imposed for the analyses to evaluate the case where the operator initiates a reactor trip based on system conditions even though an automatic reactor trip would not have occurred.

Q.35 Provide the justification for the selection of 60 percent as the criteria.

A.35 The 60% value was used as the criteria since the estimated relief capability of a safety valve is approximately 60% of the rated capacity when the pressure is at or slightly above the safety valve setpoint. Thus, if the calculated steam relief is less than 60% of the valves' relief rating, the safety valve will be adequate to relieve the steam and limit the pressure to prevent opening of the safety valve with the next highest pressure setpoint. The 60% setting was previously specified for use in determining the RCP trip setpoint in the basic version of the WOG Emergency Response Guidelines, which were found to be acceptable by the NRC as reported in a letter from D. F. Ross to Cordell Reed, dated November 5, 1979.

Q.36 Clarify what assumptions should be made if credit should not be taken for these pumps. Should all of the heat removal be made by the remaining loops or should some credit be given for natural circulation in the loops that do not have RCPs running?

A.36 For those plants where an RCP or RCPs are automatically stopped following reactor trip, no credit for heat removal should be accounted for in those loops. The corresponding setpoint would then be conservatively calculated assuming no heat removal in the loops with idle RCPs. This is appropriate since reverse flow will be established in the loops with idle RCPs and typically no heat removal will occur.

Q.37 Provide the basis for these instrument uncertainties because even the 90 psi for normal containment conditions is about as large as the 91 psi from all of the other factors considered.

A.37 It is noted that the instrument uncertainties used in the report are typical and are not representative for any specific plant. The wide range RCS pressure instrument uncertainty for normal containment conditions is typically 3 percent of span with a span of 3000 psi, which yields an uncertainty of 90 psi. A sample breakdown of the channel accuracy error components for RCS pressure is provided in the Rev. 1 ERG Executive volume in the Generic Instrumentation sub-section of the Generic Issues section. The 91 psi shown on page 66 of Ref. 1 is the sum of the 3% accumulation allowance for the safety valve and the pressure differences between the steamline safety valve pressure and the RCS pressure instrument which was determined in the sample calculation.

Q.38 Why will voiding not occur first at the top of the U-tubes?

A.38 Void formation does not occur at the top of the steam generator U-tubes first, since the steam generator is capable of removing heat generated by the core. This results in a slightly cooler fluid temperature at the top of the U-tubes which corresponds to slightly more subcooling at that location. This results in a slight delay in void formation behind locations with slightly lower saturation pressures such as the core and upper plenum. Also, refer to WCAP-9600 for additional details on system response and voiding trends.

Q.39 How is loss of subcooling treated in a loop if the RCP is not running in that loop?

A.39 For subcooling based on the hot leg RTDs the minimum subcooling is determined using the loop with the highest hot leg temperature. If the RCP is not running in one loop, reverse flow will be established in that loop. With reverse flow, the hot leg temperature, for a typical case, will be colder than the remaining loops which will result in a higher subcooling in the idle loop. Hence the stopped RCP will not have an impact on the determination of the minimum subcooling. If the subcooling measurement is based on the core exit thermocouples, the minimum subcooling will also not be affected if the RCP is not running in a loop.

Q.40 How are uncertainty numbers derived?

A.40 The subcooling uncertainties of 17°F and 59°F for normal and adverse containment conditions, respectively, were determined for the sample plant. The subcooling uncertaintes were derived by determining the effect of the RCS pressure uncertainty on the saturation temperature at a pressure of 1150 psia, and then statistically combining the saturation temperature uncertainty with the uncertainty in the RCS temperature measurement. The subcooling uncertainty for adverse containment conditions is substantially higher because of the increased uncertainty in the RCS pressure for adverse containment conditions and the corresponding effect on the saturation temperature.

Q.41 How are these uncertainty numbers derived?

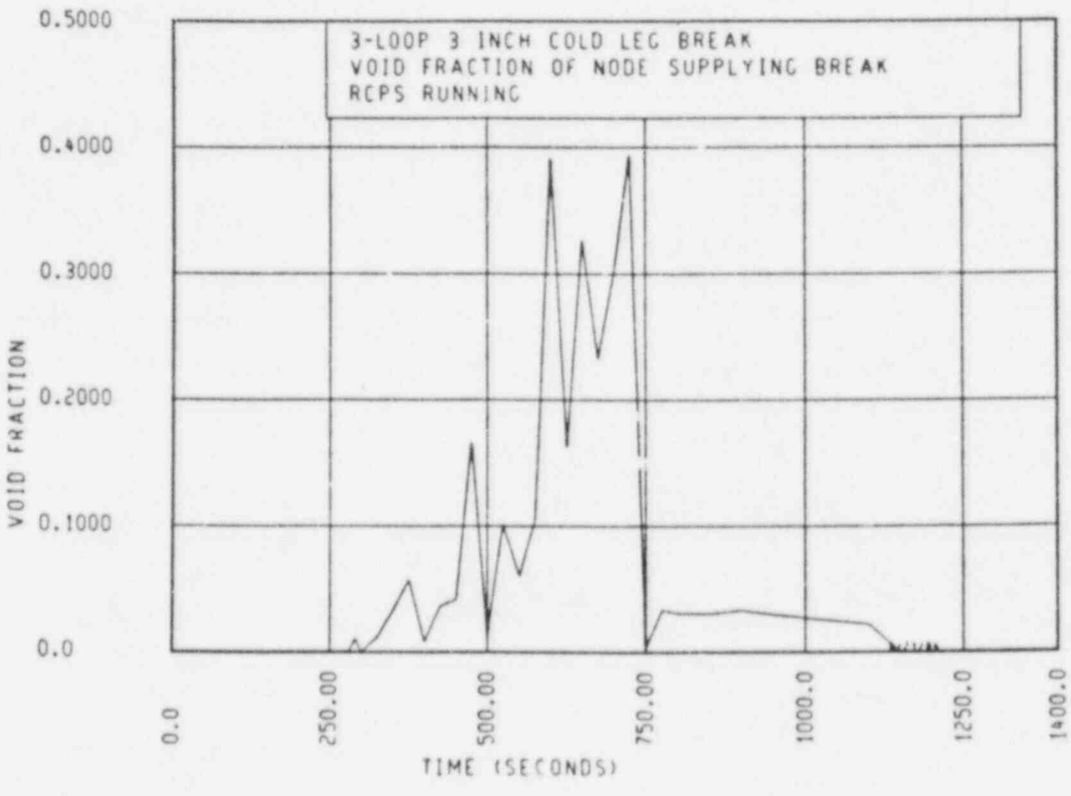
A.41 The secondary pressure measurement uncertainties of 39 psi and 169 psi respectively, were determined for the sample plant based on the steamline pressure instrument uncertainty. The uncertainties were assumed to be 3% and 13% of span for normal and adverse containment conditions, respectively, and the instrument span was assumed to be 1300 psi. Note that for this sample plant, it was assumed that the transmitter for the secondary pressure instrument is located inside containment and would be affected by the containment conditions, which is not the case for most plants.

Q.42 What does it mean to drain completely if the pumps are still running?

A.42 Draining of the Steam Generator tubes cannot occur prior to the RCS pressure reaching hot leg saturation pressure. Only at this time can steam volumetrically replace the liquid in the steam generator tubes and liquid be forced out. Continued RCP operation has two competing effects on tube draining: one is forced flow through the tubes, while the competing effect is the forced inventory loss from the loop seal region. Eventually, even with RCPs operational, the S.G. tubes will continue to drain due to loss of continuous liquid flow to the cool side of the tubes while the RCPs force liquid from the loop seal region.

Q.43 What is the void fraction vs. time supplying the break for the pumps on case?

A.43 See the attached figure.



Void Fraction Of Node Supplying Break

Q.44 What is the basis for the last sentence?

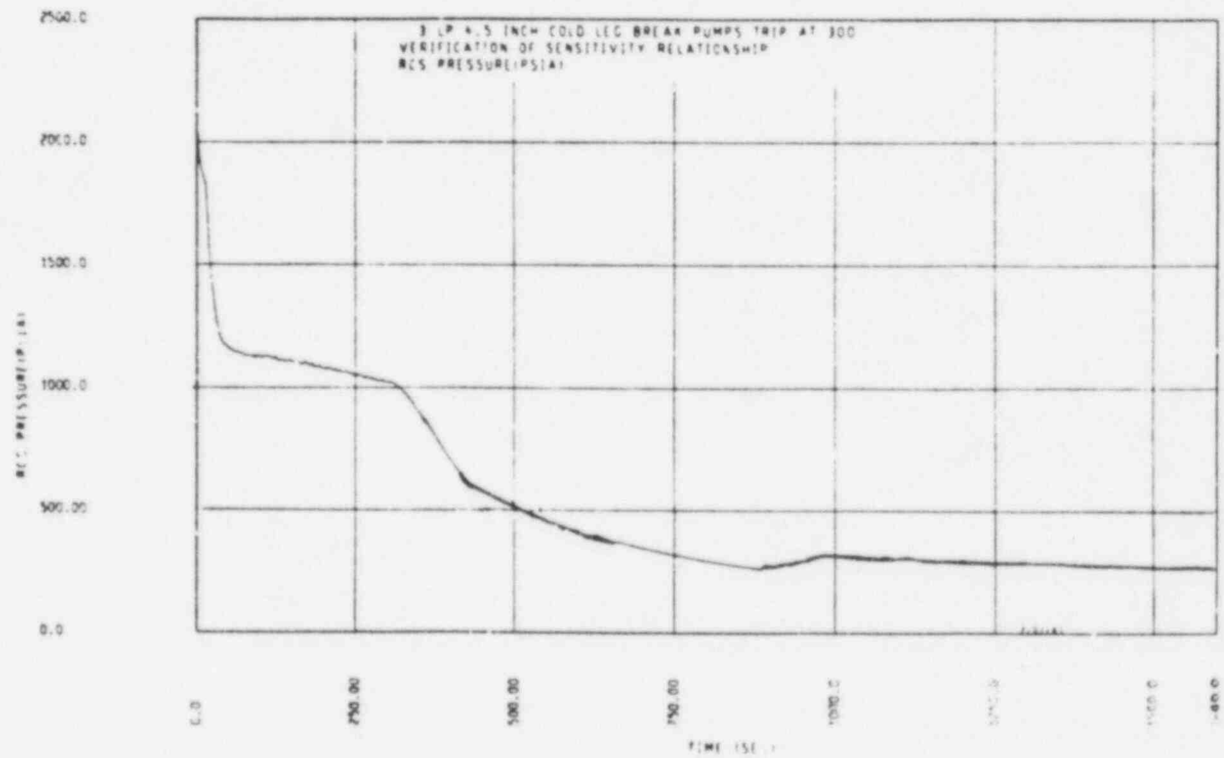
A.44 This statement is based on the results presented in table 2 of reference 2. This table demonstrates that the minimum operator action time available to trip the RCP prior to "critical inventory" time is greater than 2 minutes. Page 4 of reference 2 describes "critical inventory" time as the time beyond which continued RCP operation would result in more limiting PCT results than the existing plant FSAR analysis. Therefore, the current plant-specific FSAR analyses remain valid under the criteria of generic letter 83-10c and d, since more than 2 minutes exist from break initiation to "critical inventory" time and the existing FSAR analyses are conservative prior to "critical inventory" time.

Q.45 What causes the peak in the core mixture level after the initial drop in Figures 4 and 5 of reference.

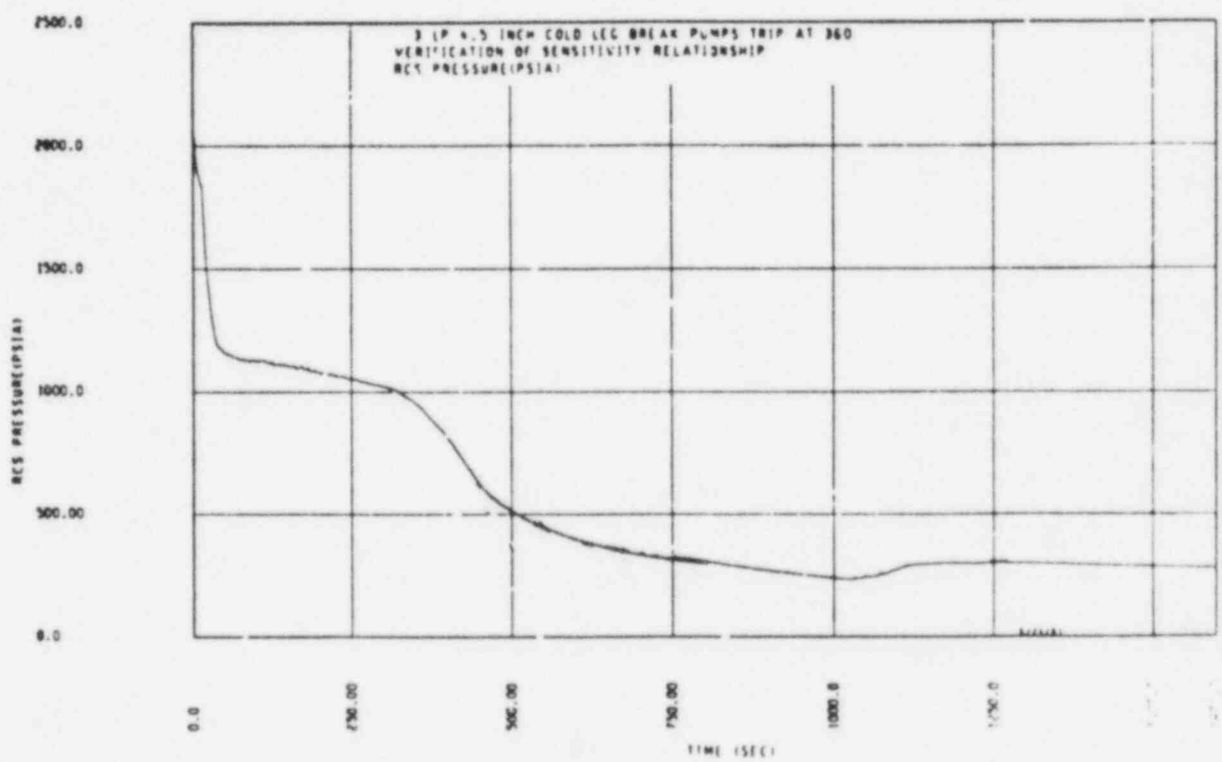
A.45 The initial drop in the figures are caused by the collapse of core voids following reactor trip. The core mixture level peak which occurs following this depression is caused by the draining of the cool side of the steam generator tubes which is driven by the continued RCP operation. The water which is drained from the tubes is forced into the core due to the continued RCP operation. Upon completion of the draining of the tubes, the core mixture level again begins to decrease.

Q.46 Provide the primary pressure, void fraction, and PCT curves for the 300s and 360s RCP trip time cases shown in Figure 4 and 5 of Reference 2.

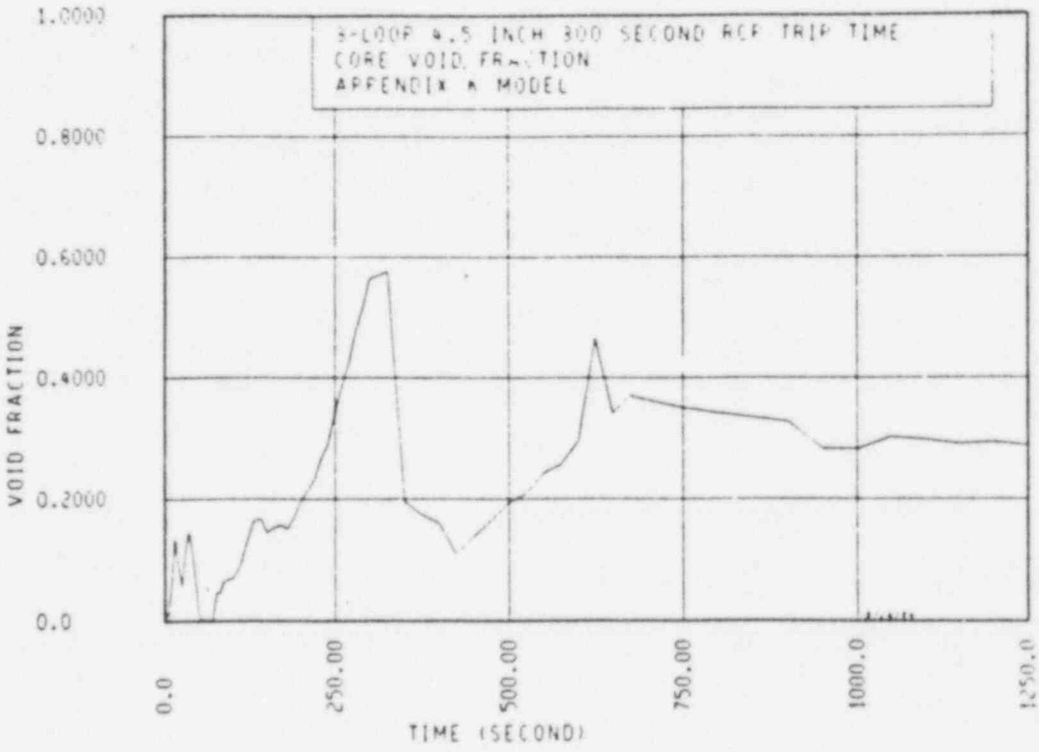
A.46 See the attached figures.



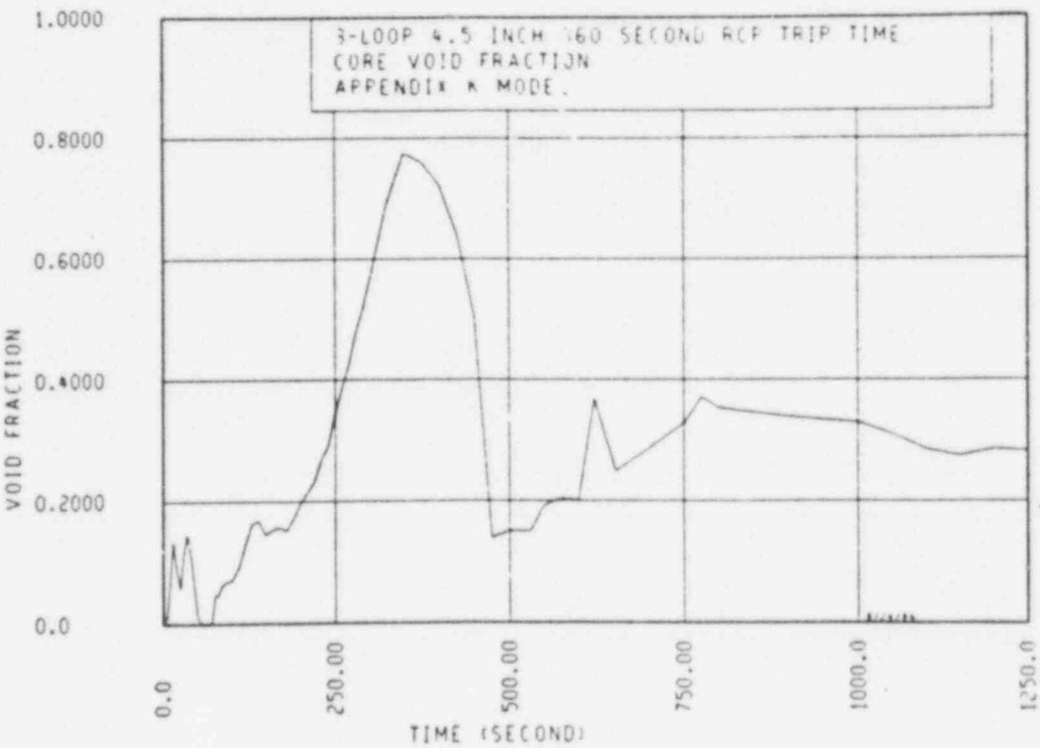
RCS Pressure 300 Second RCP Trip



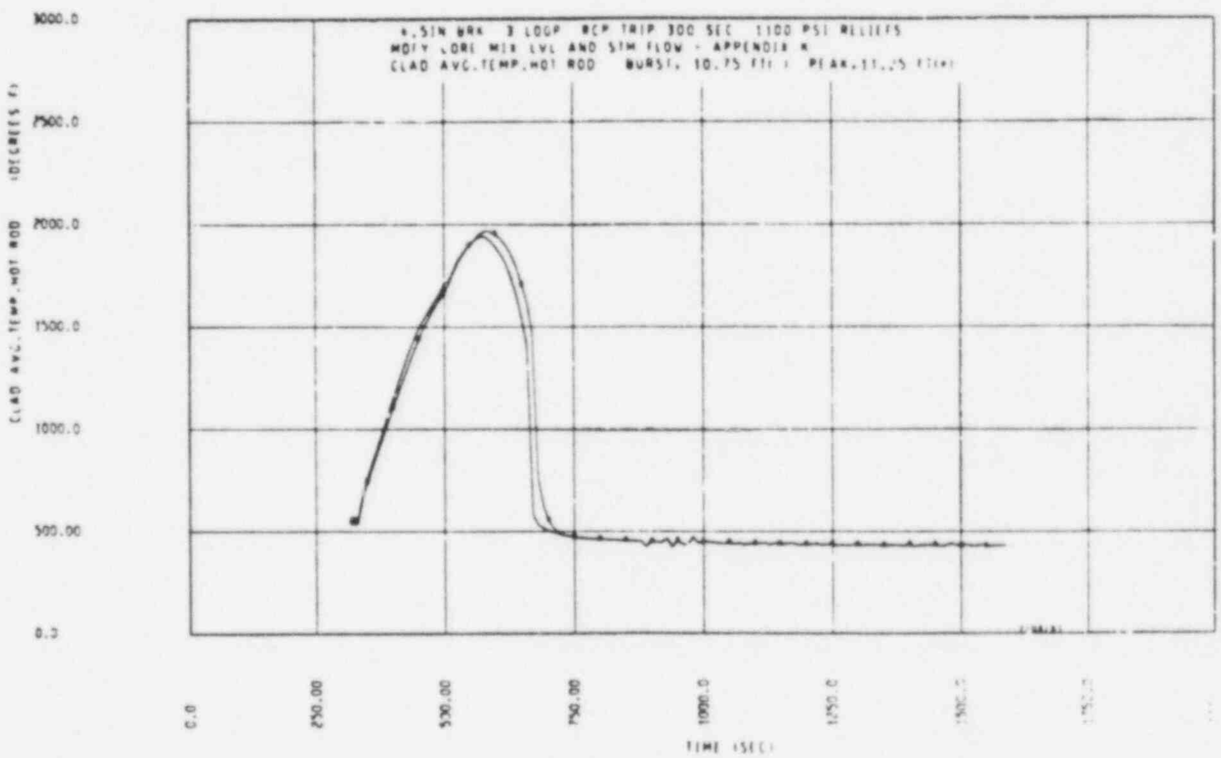
RCS Pressure 360 Second RCP Trip



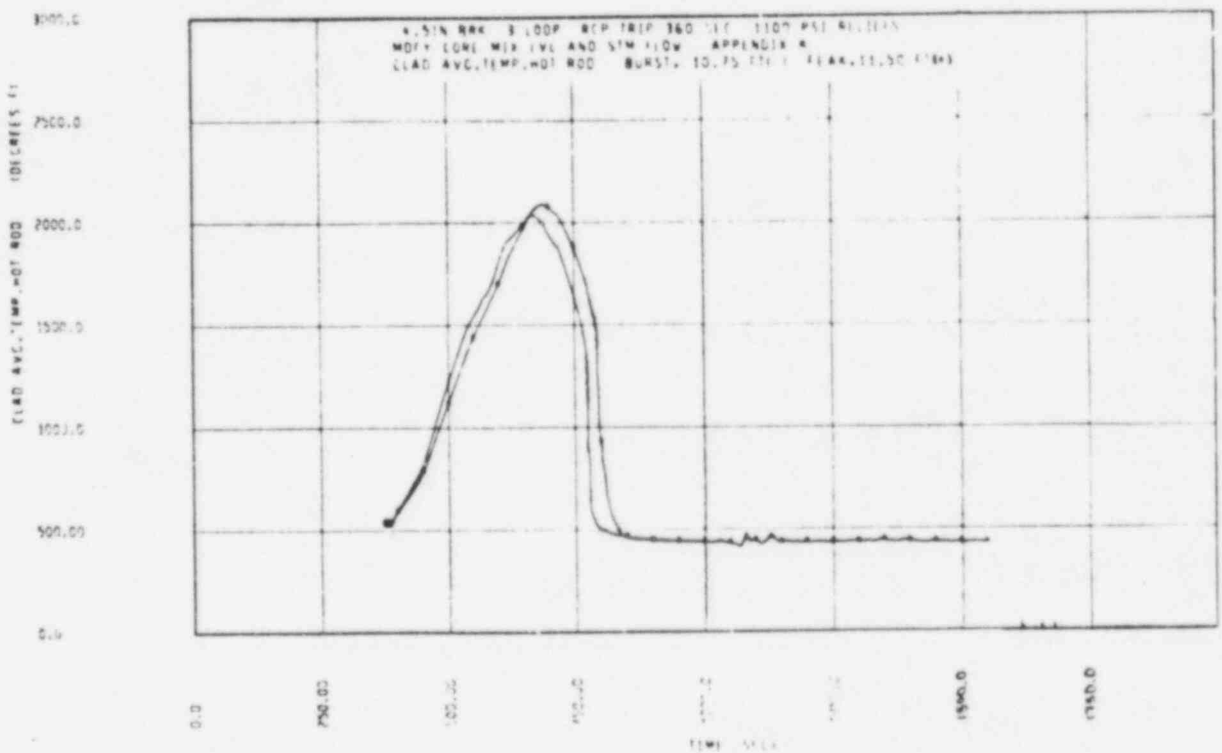
Core Void Fraction 300 Second RCP Trip



Core Void Fraction 360 Second RCP Trip



Clad Average Temperature 300 Second RCP Trip



Clad Average Temperature 360 Second RCP Trip

Q.47 What is the relative contributions of pump coastdown and break flow to the level decreases shown in Figures 4 and 5 of Ref 2. When does pump coastdown end for these two cases?

A.47 The level decreases shown in Figures 4 and 5 are due primarily to the inventory lost out the break. However, continued RCP operation produces a pressurized downcomer and allows a forced flow core mixture level to be maintained. When the RCPs are tripped, sufficient inventory has been lost to cause the core mixture level to drop below the top of the active fuel as RCP coastdown begins. RCP coastdown occurs rapidly early after trip resulting in the loss of approximately 48 percent of pump speed after 50 seconds. This allows the forced downcomer and core mixture levels to equilibrate which results in the rapid drop in core mixture level.

RCP coastdown is predicted to end at 1050 sec and 1200 sec for the 300 and 360 second RCP trip times respectively. This represents the time at which pump speed drops below 1% of its original pre-trip value.

Q.48 Would the PCT be higher by tripping before 360s?

A.48 No, since tripping the RCPs prior to 360 seconds would result in a less severe core uncovery than predicted in Figure 5. This is due to the fact that prior to 360 seconds breakflow in this Appendix K case continues to exceed pumped safety injection flow; therefore, RCP trip prior to 360 seconds would result in an earlier break uncovery with a resulting faster depressurization to the point where pumped S.I. would exceed breakflow. This would result in the termination of inventory depletion with a corresponding reduction in the severity of core uncovery. The combined effects would result in a reduction in both the clad heatup period and ultimate peak clad temperatures.

Q.49 Why is this S.I. spilling assumption made even though best-estimate S.I. flow rates were assumed on page 9 of Ref. 2?

A.49 Had a break location other than the cold leg location been chosen, the assumption of 1 S.I. line spilling against RCS backpressure would <u>not</u> have been used. However, as regards establishing that cold leg break locations result in the most limiting transient results, the S.I. spillage assumption is not overly conservative, simply consistent. Best estimate S.I. flow rates were presumed since both high head S.I. pumps deliver flow, whereas only one high head pump would be available with Appendix K single failure assumptions.

Q.50 Provide the justification for concluding that the 0.06 constant predicts too great a degradation for the PWR pumps.

A.50 Refer to Westinghouse Owners Group letter OG-60 dated June 15, 1981, "LOFT L3-6 predictions", and

NS-TMA-2428 Letter from T. M. Anderson (W) to Paul S. Check (USNRC), "L3-6 changes for blind post-test predictions", March 30, 1981.

Q.51 Why is the LOFT-basis number more realistic for a PWR pump when LOFT also does not use a full scale pump?

A.51 Refer to question 50 response.

Q.52 What Westinghouse study is the basis for this impact?

A.52 Internal Westinghouse sensitivity studies using the WFLASH Evaluation Model were performed which compared different fuel types while holding all other parameters constant.

Q.54 For figure 7 and table 5 of Ref. 2, why is the value given for the 3-inch case the maximum when only one value was run for this size?

A.54 Based on the trends predicted for the other break sizes the limiting RCP trip time was determined to be the time at which the breakflow quality becomes 1.0 (all steam breakflow). Also, two cases are available for checking these results, the pumps running case and the 930 second RCP trip case. Based on the pumps running case the inventory loss will cease when breakflow becomes all steam (930 seconds) i.e. SI is greater than breakflow at this time. RCP trip prior to 930 seconds results in the breakflow becoming all steam sooner causing a reduction in inventory depletion and a corresponding increase in the predicted minimum core mixture level. Delaying RCP trip beyond 930 seconds results in a less severe core uncovery (since inventory is being replenished) while maintaining forced core cooling while continuing to depressurize to the accumulator actuation setpoint. Tripping beyond 930 seconds will reduce the predicted clad heatup duration since less inventory is needed to reach the recovery mixture level when RCP trip occurs. Therefore, PCTs would be reduced by either tripping the RCPs prior to or beyond the "critical trip time" of 930 seconds.

Q.53 How much different would the result be if full S.I. flow was available and not assumed spilled in one delivery line and could this change in assumption shift the choice of worst case plant to a different plant?

A.53 The relative differences between safety injection systems remain consistent regardless of the S.I. spillage assumption. In other words, all plant values for SI/MW will become larger, with the relative differences between plant types remaining fairly consistent. No shift in limiting plant choice will occur.

Q.55 In table 5 of reference 2 why is the 3.3 in case the worst case when nothing was given between 3.3 and 4.0 in. and the peak value for the 2.5 in. case is greater than for the 3.0 in case?

A.55 The intent of this analysis was not to run every possible incremental break size but rather to determine to the best of our ability a bounding break size. Based on figure 7 of reference 2 we have demonstrated that the trend of increasing PCTs with decreasing break size has ended beyond the 3.3 inch break size, specifically by the 3.0 inch case. Also, since the predicted clad temperature for the cases analyzed are so low (< 1300°F) no challenge to the Appendix K limit of 2200°F is expected to occur due to small changes in break size.

In regards to the 2.5 in. break case resulting in a greater predicted PCT than the 3.0 inch case, the 2.5 inch case resulted in a 3°F higher clad temperature even though this case was conservatively modeled (no accumulators modeled even though sufficient depressurization to accumulator actuation pressure is predicted to occur). Therefore, had this case been modeled on a consistent basis with the 3.0 inch case, the resulting PCT would be much less than the 3.0 inch case.

Q.56 Does this mean the break flow is all steam while the RCPs continue running or does it mean the break flow becomes all steam after RCP trip.

A.56 The procedure used to determine the critical RCP trip time is as follows:

1) Run the continued RCP operation case

2) From 1 above determine the time at which break flow becomes all steam.

3) Restart case 1 prior to break flow becoming all steam and trip RCPs at the determined critical time from 2 above.

4) Restart case 1 with various other RCP trip times.

Q.57 Is there any data available for pump-trip times closer to the peaks that would verify this criterion more directly?

A.57 No. The closest data point available following the critical RCP trip time is for the 2.5 inch break case which has RCP trip occurring 68 seconds after the critical RCP trip time. Table 5 of ref. 2 verifies that the critical trip time indeed predicts the highest clad temperatures, thereby verifying the critical trip criterion.

Q.58 How is the accumulator injection curve derived and verified for different depressurization rates?

A.58 The method for deriving the accumulator injection curve is to revise the RCS depressurization curve for the break size of interest predicted with the standard WFLASH Appendix K accumulator model. Assuming a more realistic RCS depressurization following accumulator actuation time than the standard model result allows the calculation of a long term "averaged" accumulator flowrate assuming isothermal cover gas expansion as recommended by B. Sheron in Reference 4. This flowrate can then be input as a constant pumped safety injection flow versus RCS pressure. This eliminates the unrealistic RCS cold leg depressurization behavior from causing excessive accumulator injection flow such as is predicted to occur with the standard WFLASH model. The flowrate input can then be verified by using the RCS pressure curve generated by inputting the identified accumulator flowrates. The method used is to choose two RCS pressures, the accumulator injection setpoint pressure and the RCS pressure slightly beyond the predicted PCT time. Again, assuming an isothermal cover gas expansion, a proper flow rate value for input to the code can then be derived; the input flow rate value is compared to this value. Additional iterations can be performed depending on the results of the calculation, and WFLASH can again be restarted with the new value.

Q.59 How is the curve to be used for each break size transient validated after running the transient?

A.59 Refer to the response to question 58.

Q.60 How is the tape processed and what is judged unrealistic?

A.60 Unrealistic core mixture level swelling and steam flow spikes are edited out of the WFLASH output tape and a linear interpolation between the realistic points is then performed for continuity. This edited tape is then used as input to the LOCTA code.

Unrealistic core mixture level swelling and core steam flow rates are predicted to occur due to the coarseness of the core axial nodes in WFLASH. During slow core recovery transients there is a core mixture level and steam flow spike predicted when the mixture level enters a new core axial node. These mixture level swells and steam flow spikes are unrealistic and are caused due to core model limitations. Since they provide an unwarranted fuel cooling improvement, they are edited out.

Q.61 Why does the model make the results conservative rather than best estimate, since it is trying to model actual behavior?

A.61 This model results in conservative predictions since the use of long term "average" flow value will delay the core recovery transient and result in higher ultimate PCTs. It was felt that this model represents a "more realistic" prediction of accumulator injection without the additional expense of detailed, costly model development efforts which would have delayed responses to NRC generic letter 83-10c and d without substantial improvement of results.

Q.62 How is the core mixture level defined for the part of the transients when the RCPs are still running?

A.62 Details regarding the WFLASH core mixture level model and its verification are available in WCAP-9764 titled "Documentation of the Westinghouse Core Uncovery Tests and the Small Break Evaluation Model Core Mixture Level Model".

Q.63 For ref. 2, are the core mixture levels given in table 6 measured from the bottom of the core, whereas the core mixture levels in the figures in Appendix B are measured from the bottom of the vessel or some other location?

A.63 As stated on table 6 of reference 2 the core mixture level is measured from the bottom of the flow skirt. This is due to the nature of the transient with the RCPs running in which the downcomer mixture level depresses to the bottom of the flow skirt. This is a realistic representation of the actual flow geometry.

Q.64 What does it mean for some of the temperature plots in Appendix B of Ref. 2 where it says "core spikes removed"?

A.64 The comment "core spikes removed" deals with LOCTA runs performed following unrealistic core mixture level and steam flow spike removal described in the response to question 60.

Q.65 What is the relationship between the PCT values given in Table 5 of Ref. 2 and the "clad avg. temp. hot rod" plots in Appendix B of Ref. 2 because the values appear to agree for some cases and yet differ by over 100°F for the 4.5 in. break case with trip at 360s?

A.65 The values presented in table 5 of reference 2 should result in a direct one to one comparison with the PCT plots presented in Appendix B of reference 2. However there appears to be 2 errors under the peak clad temperature headings. The PCT values for the 4.5 in. 360 second and 4.5 in. 600 second RCP trip are incorrectly stated as 1203°F and 1071°F. The appropriate values for these cases are 1071°F and 771°F, respectively.

Q.66 Clarify why with the pumps running more void does not reach the break earlier.

A.66 Refer to the response to question 9.

Q.67 Why is there such a sharp jump in quality from nearly zero to 1.0 with the pumps still running.

A.67 The break is modeled to occur at the bottom elevation of the affected cold leg pipe. While sufficient liquid mass inventory exists in the node, saturated liquid is feeding the break from the stratified break node. At the time breakflow is predicted to become all steam, sufficient inventory loss has occurred to uncover the break. Therefore, breakflow becomes single-phase steam.

Q.68 Clarify why the core mixture level does not reflect that the RCPs are pumping pure steam after about 900s.

A.68 The mixture level plot does demonstrate that the RCPs are pumping pure steam, since at approximately 930 seconds the core mixture level begins to drop. The mixture level does not drop out dramatically since there is still sufficient forced flow available to maintain a forced flow core mixture level. This can be seen by comparing the pumps running and the 930 second RCP trip case. In the 930 second trip case pump trip and coastdown does not allow for sufficient forced flow, so the core mixture level tends to equilibrate with the downcomer mixture level. This continues to be true as sufficient system inventory becomes available to refill the system.

Q.69 Are there any SGTR transients that will cause the plants to trip even though the rupture is smaller than the design-basis single-tube event.

A.69 The answer to this question is addressed in the response to Q.21.

Q.70 How would the operator determine if he had a SBLOCA or a SGTR for a SBLOCA of about the same size as a SGTR?

A.70 The intent of RCP trip criteria parameter selection is to provide the operator a symptom to base RCP trip requirements independent of event identification. The intent of the criteria is to minimize inventory depletion in the event of actual size SBLOCAs while minimizing RCP trip for SGTRs, non-LOCAs and certain SBLOCA cases (safety injection flow is sufficient to offset inventory depletion). These criteria were developed so that when exceeded, RCP trip would be indicated regardless of the event in progress. Also, RCP trip would not be necessary for a SBLOCA of equivalent size to a single tube rupture. The distinguishing characteristics of SGTRs over SBLOCAs of equivalent sizes would be high secondary side radiation and ruptured steam generator level response.

Q.71 Are the RCPs expected to trip for smaller size SBLOCAs than given in Refs. 1 and 2 and can these smaller sizes lead to repressurization and the need to use the PORVs to control primary pressure?

A.71 RCPs are expected to be tripped for break sizes smaller than those presented in references 1 and 2. Hypothesize a break size where break flow and SI flow equilibrate at a pressure higher than the trip setpoints, and decay heat cannot be fully removed by the Steam Generators and the break. The RCS will repressurize to a pressure at which sufficient heat transfer will be available to remove the decay heat produced by the core through natural circulation flow into steam generators and flow out the break. No safety hazard will exist and the PORVs should not be challenged. For very small breaks, if S.I. continues to exceed breakflow, specific S.I. termination criteria are provided in the ERGs so the PORVs should not be challenged. Refer to WCAP-9600 for further discussion of break sizes smaller than those presented in references 1 and 2.

Q.72 How has the requirement been met to establish guidelines and procedures for cases where RCP trip can lead to hot, stagnant fluid regions at primary system high points?

A.72 Specific Optimal Recovery Guidelines (ORGs) have been established which deal with plant recovery under voided conditions in stagnant RCS regions with RCPs tripped. Guidelines ES-0.3 and ES-0.4 provide recovery guidelines for natural circulation cooldown with steam voids in the vessel both with and without the availability of RVLIS instrumentation with no accident in progress. All accident recovery guidelines include contingencies for cooldown and depressurization without RCPs operating.

Q.73 We will be performing independent, confirmatory analyses of selected SBLOCAs and SGRs. In order to benchmark our calculations, please provide plots of the following parameters for the 3-loop generic PWR, for the 3.3 inch diameter SBLOCA and for the design base SGTR (where noted (*) these data were presented in the submittals for the SBLOCA case,

1) Reactor coolant system pressure,*
2) Secondary-side pressure, faulted and intact loops,
3) Hot leg and cold leg temperatures, faulted and intact loops,
4) Core mixture level,*
5) Small-break or SGTR rupture mass rates,
6) Integrated small-break or SGTR rupture mass flow,*
7) Hot rod temperatures,*
8) Reactor coolant loop mass flow rates, faulted and intact loops,
9) Steam and feedwater (main and auxiliary) flows, faulted and intact loops, and
10) Safety injection and accumulator flow rates

A.73 The following data for the 3-loop generic PWR design base are provided:

1) RCS pressure - Figure 1
2) Secondary side pressure, ruptured - Figure 2
   Secondary side pressure, intact - Figure 21
3) Hot leg and cold leg temperatures, ruptured - Figure 3
   Hot leg and cold leg temperatures, intact - Figure 4
4) Core mixture level - Not applicable
5) SGTR rupture mass flow rate - Figure 3L Case 3 of Ref. 3
6) Integrated SGTR rupture mass flow rate - Figure 20
7) Hot rod temperature - Not applicable
8) RCS loop mass flow rate, ruptured - Figure 19
   RCS loop mass flow rate, intact - Figure 19
9) Steam flow rate, ruptured - Figure 5
   Steam flow rate, intact - Figure 6
   Total feedwater flow rate, ruptured - Figure 18
   Total feedwater flow rate, intact - Figure 18
(10) Total Safety injection mass flow rate - Figure 17

For SBLOCA:

The following pages contain the requested information in the form of graphs where applicable. It should be noted that only one figure is provided for Hot Leg Fluid Temperature, Cold Leg Fluid Temperature and Steam Generator Pressure. This is due to the fact that the variances in temperature and pressure for the figures would be imperceivable between the broken and intact loops, therefore, only one figure was provided.

Also, since the accumulator flow is modeled as a constant pumped safety injection flow value, it was felt that a curve would not be appropriate. The value used for the 3.3 inch 740 second RCP trip case was a constant 450 GPM when the RCS pressure dropped below 642.7 psia (approximately 855 seconds).

The small break rupture mass rates for the 3.3 inch 740 second RCP trip case was previously transmitted in Reference 3.

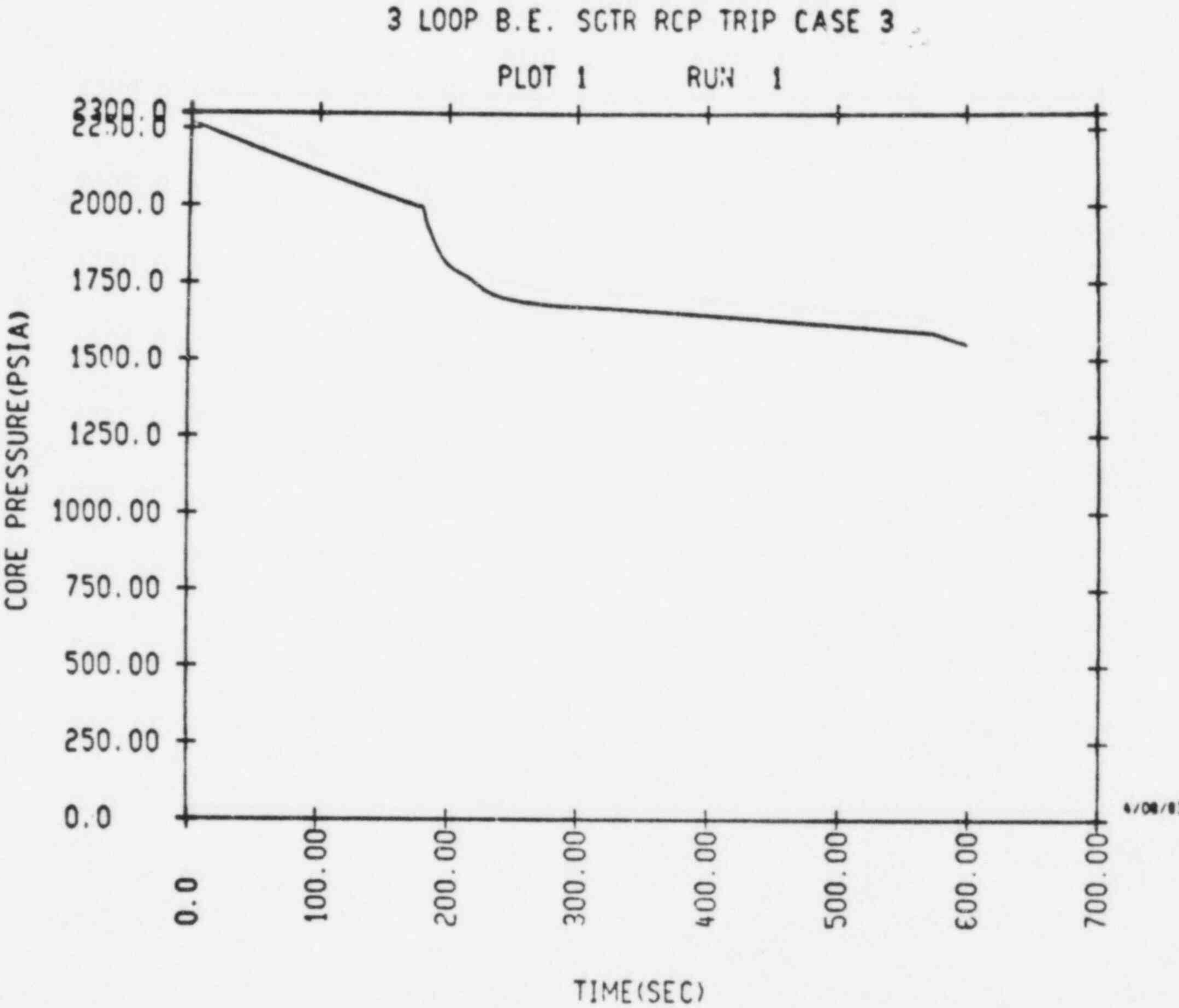


Figure 1 - SGTR RCS Pressure (PSIA)

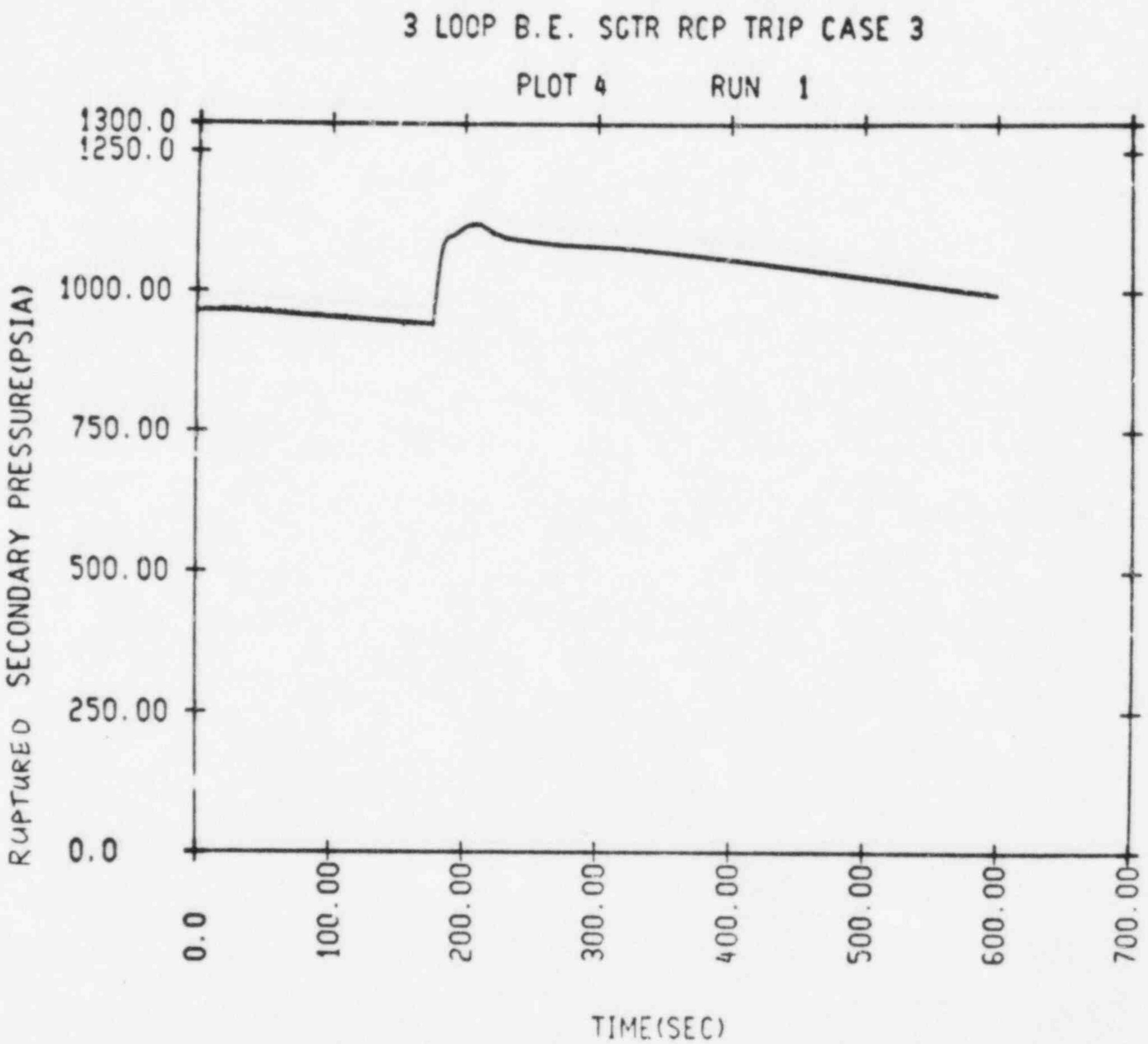


Figure 2 - SGTR Ruptured Steam Generator Pressure (PSIA)

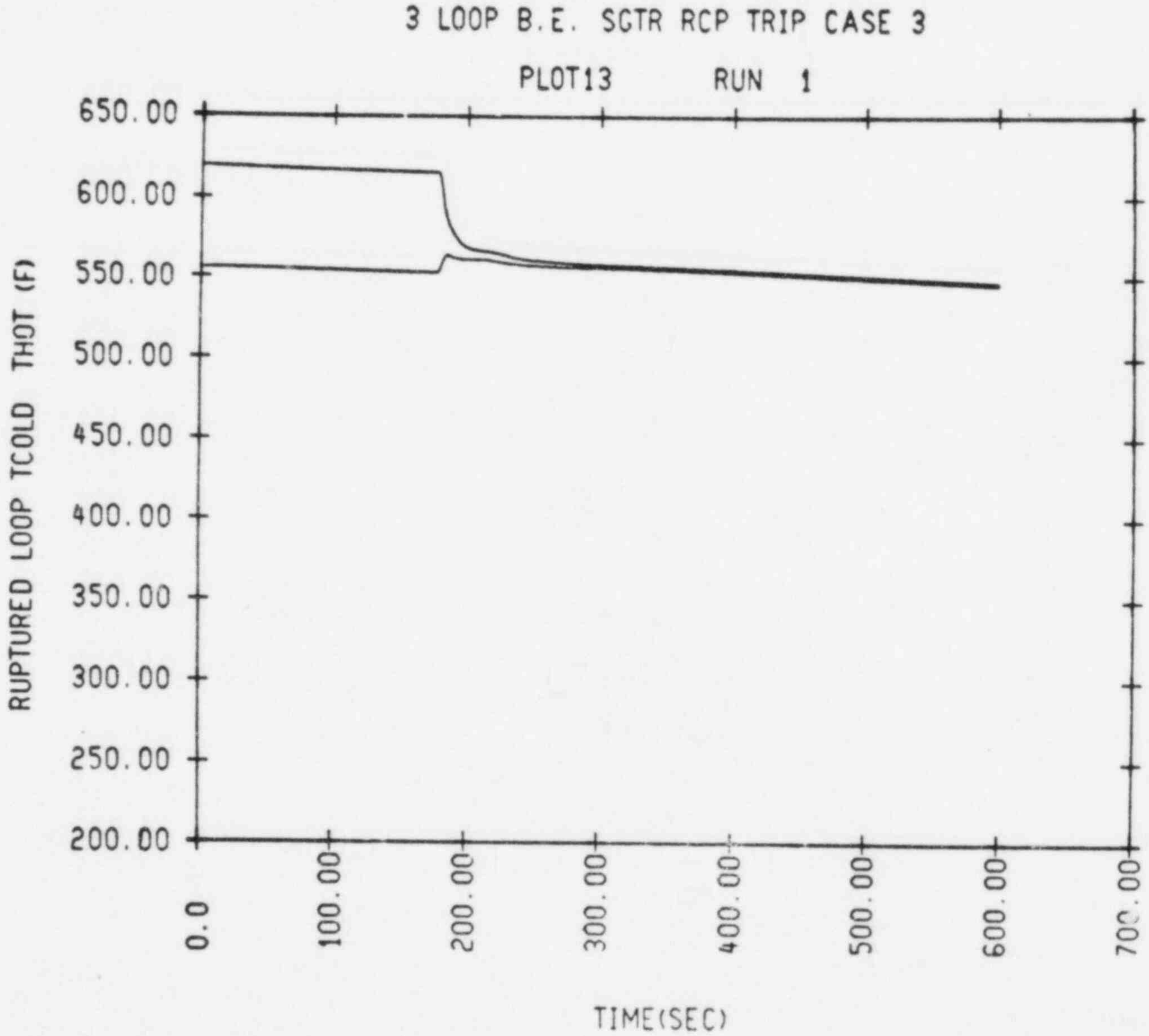


Figure 3 - SGTR Ruptured Loop Fluid Temperatures (^{o}F)

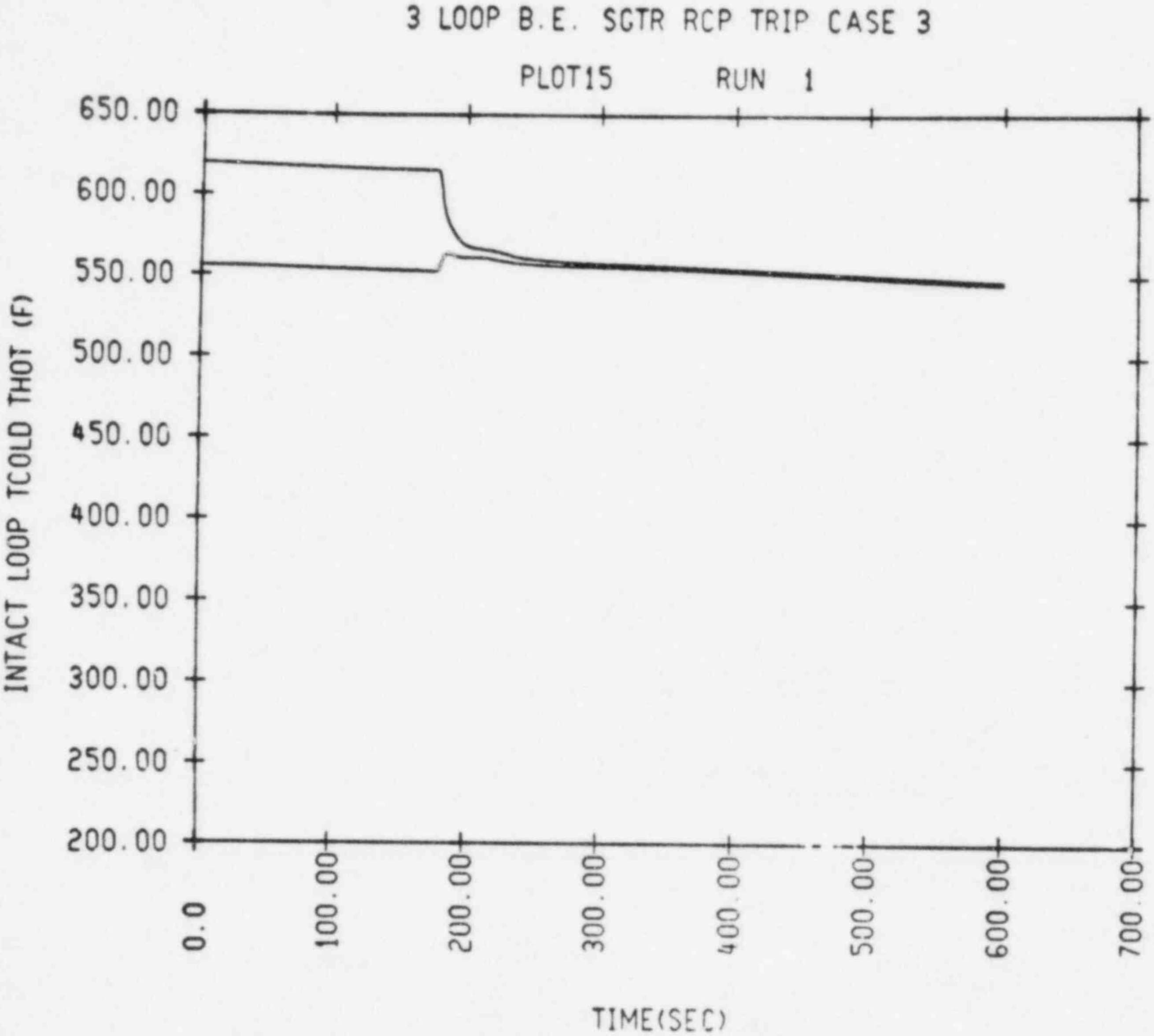


Figure 4 - SGTR Intact Loop Fluid Temperatures (^{o}F)

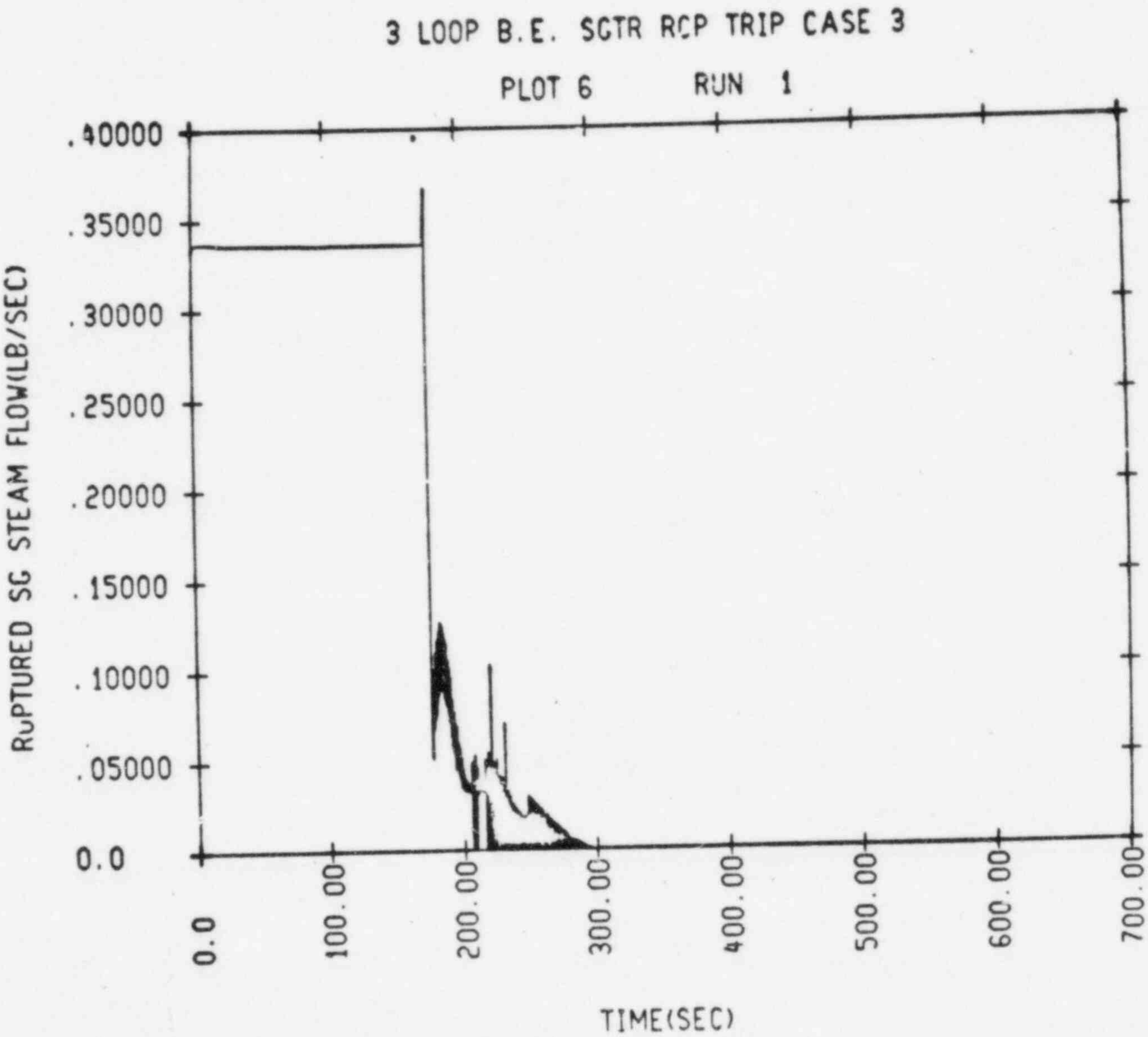


Figure 5 - SGTR Ruptured Steam Generator Steam Flow (LBM/SEC)

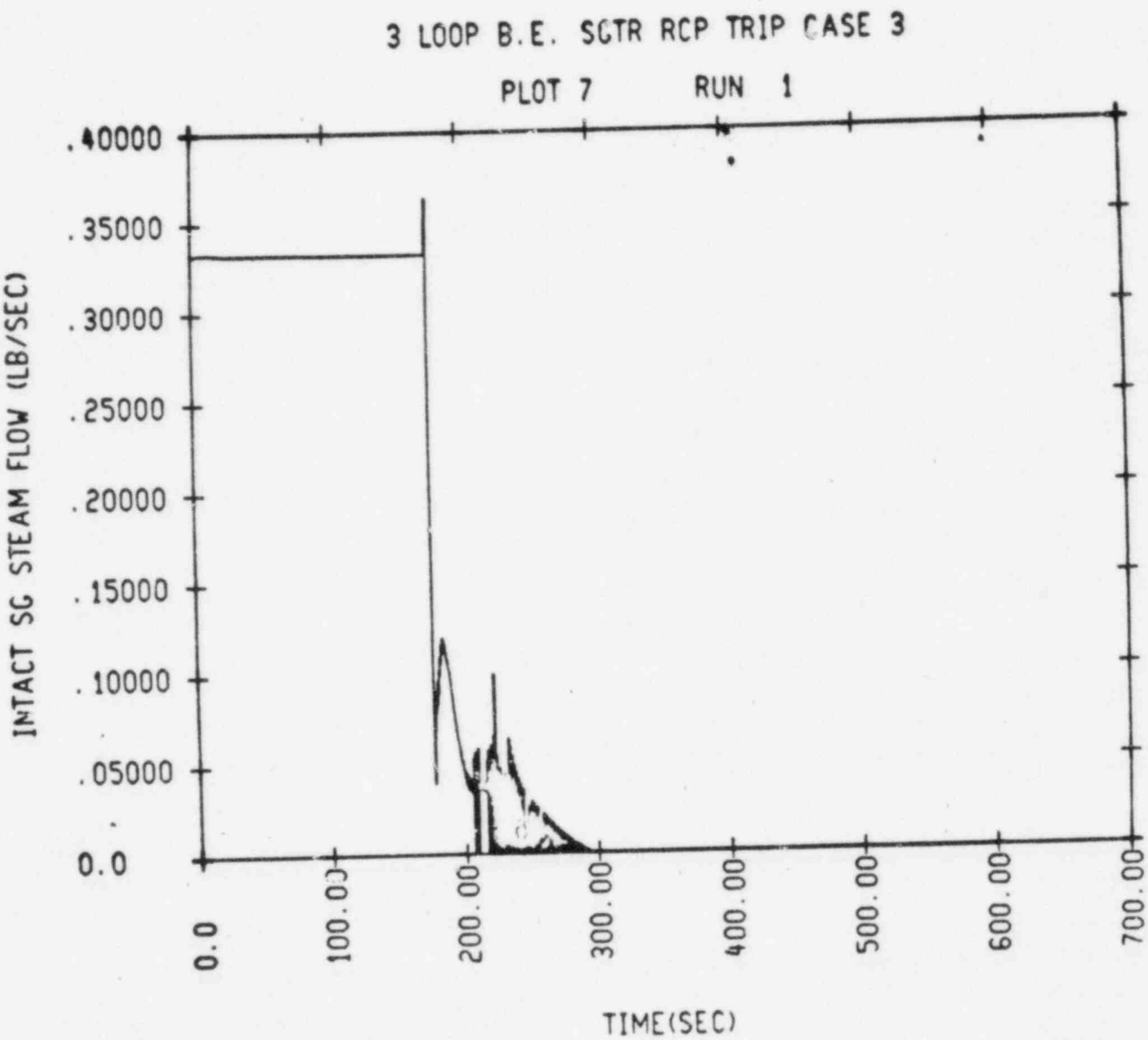


Figure 6 - SGTR Intact Steam Generator Steam Flow (LBM/SEC)

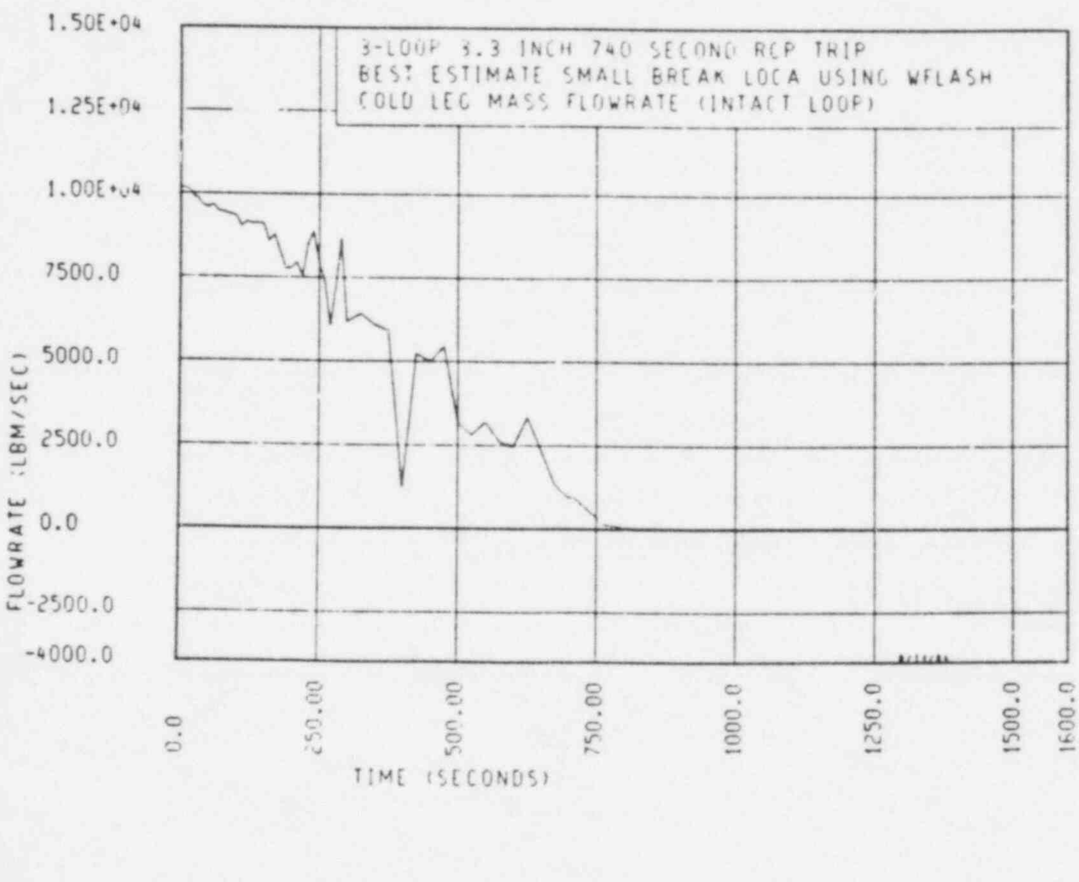


Figure 7 - SBLOCA Cold Leg Mass Flow (Intact Loop) (LBM/SEC)

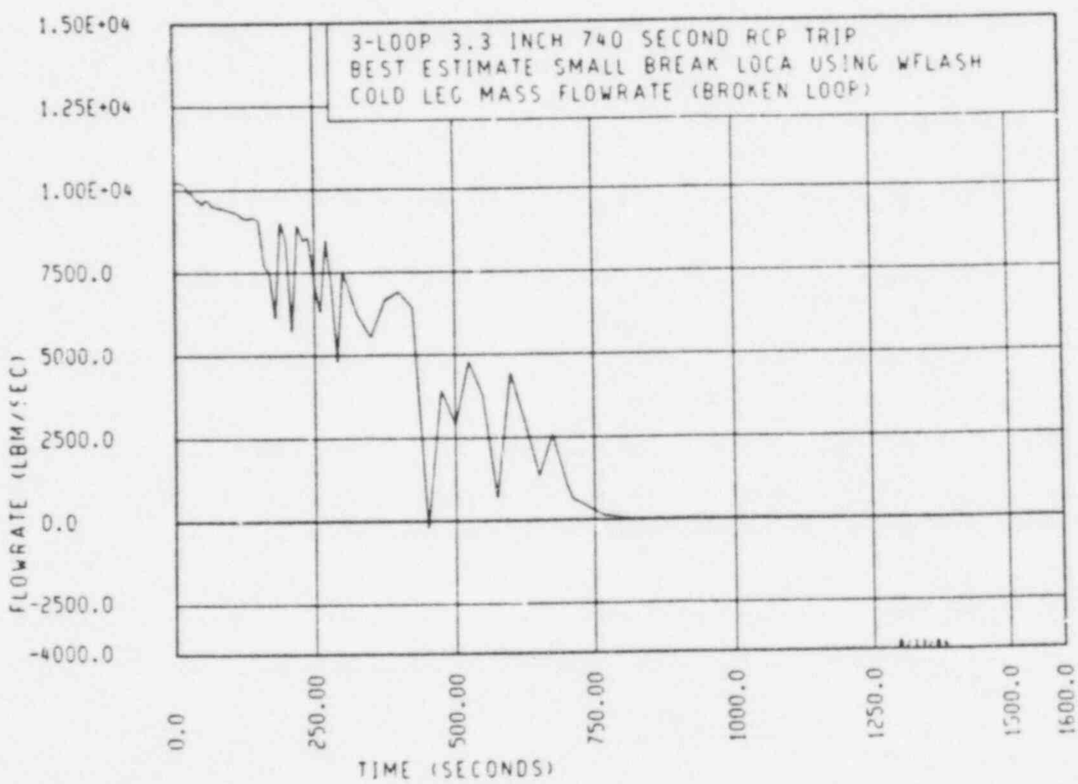


Figure 8 - SBLOCA Cold Leg Mass Flow (Broken Loop) (LBM/SEC)

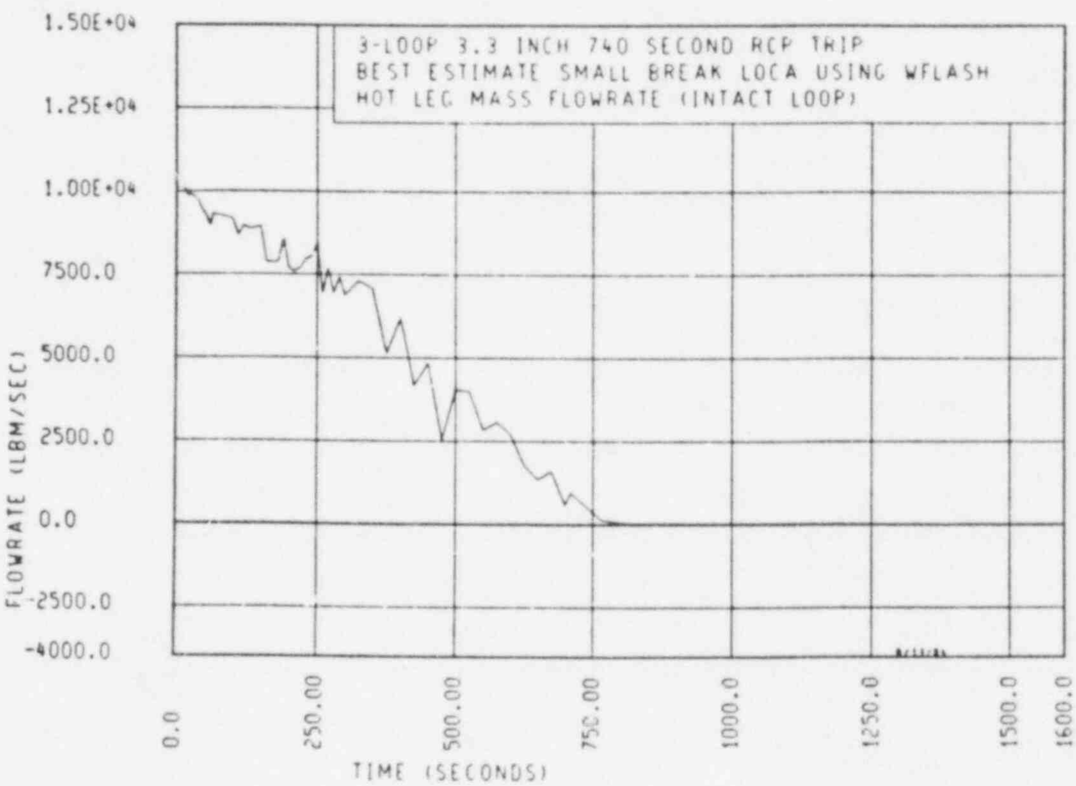


Figure 9 - SBLOCA Hot Leg Mass Flow (Intact Loop) (LBM/SEC)

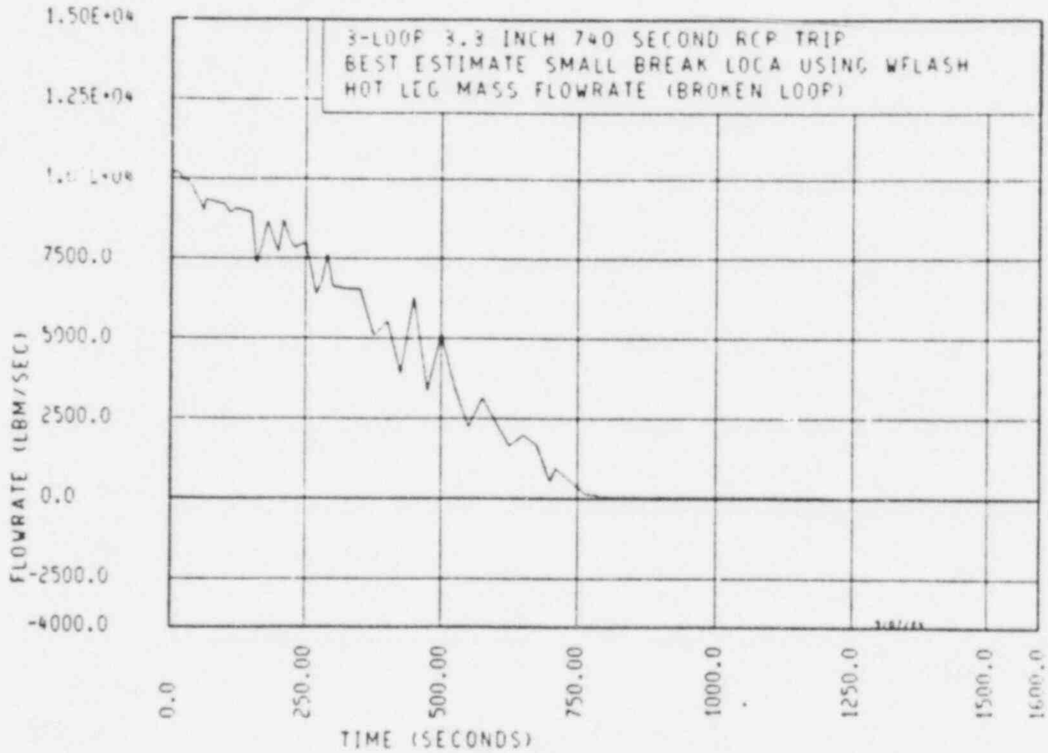


Figure 10 - SBLOCA Hot Leg Mass Flow (Broken Loop) (LBM/SEC)

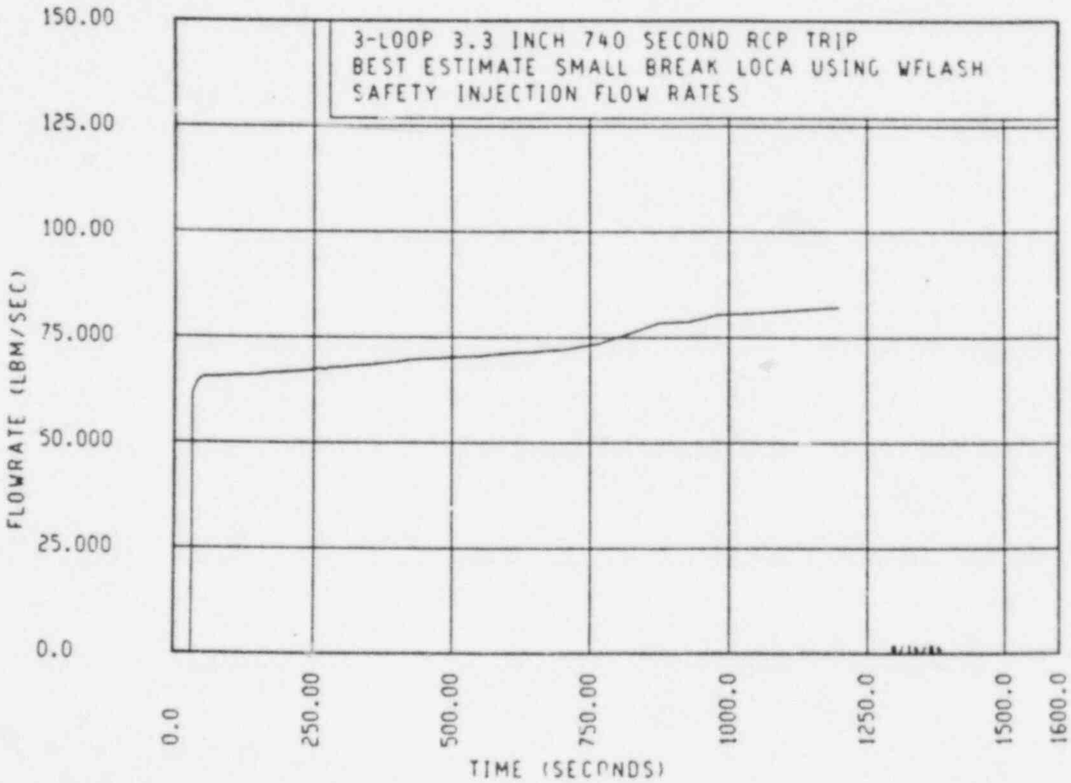


Figure 11 - SBLOCA Safety Injection Flowrate (LBM/SEC)

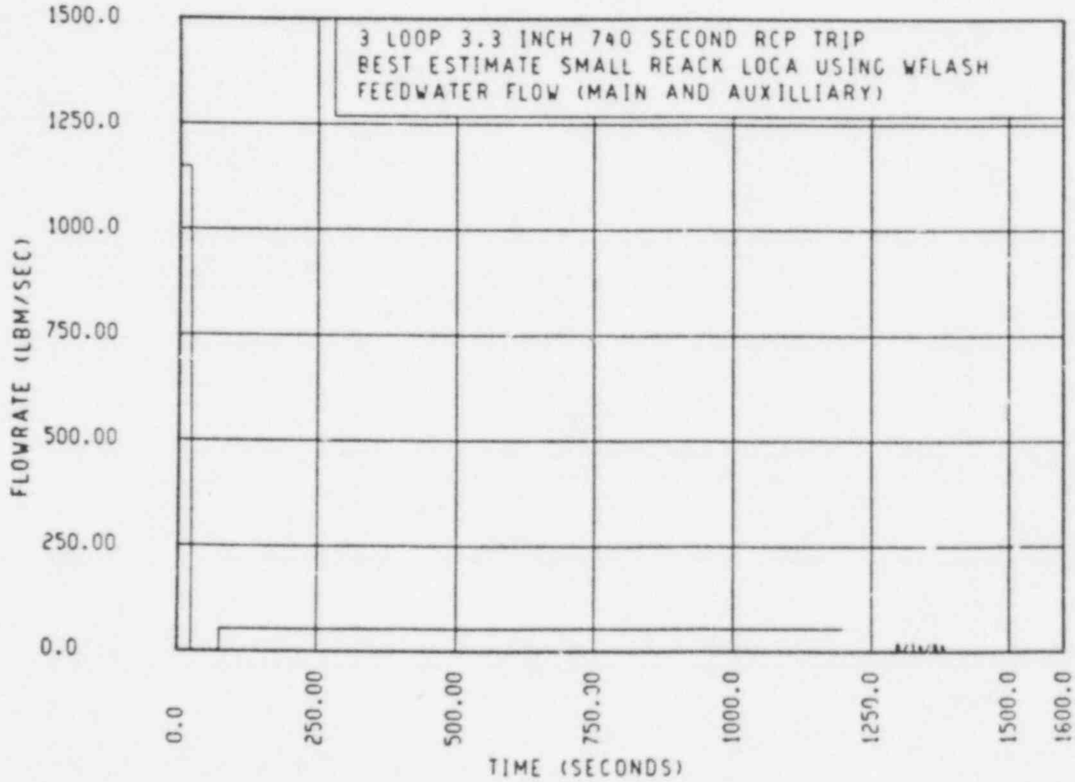


Figure 12 - SBLOCA Main and Auxilliary Feedwater Flow (LBM/SEC)

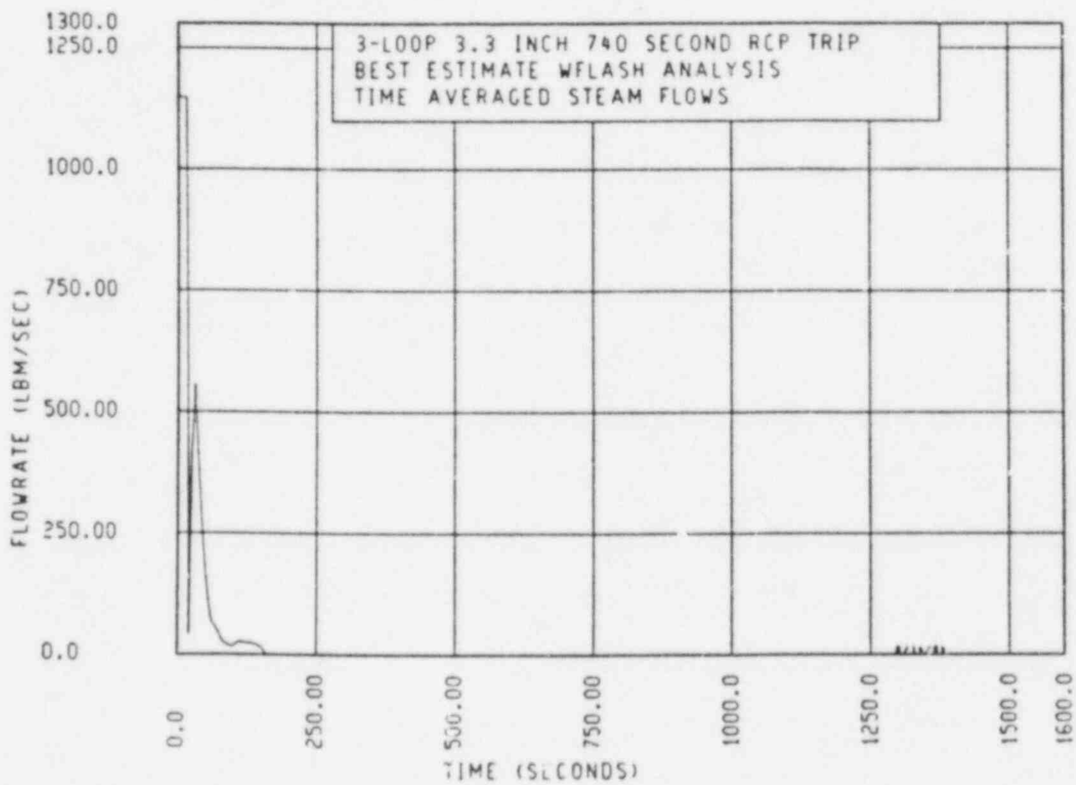


Figure 13 - SBLOCA Steam Flow (LBM/SEC)

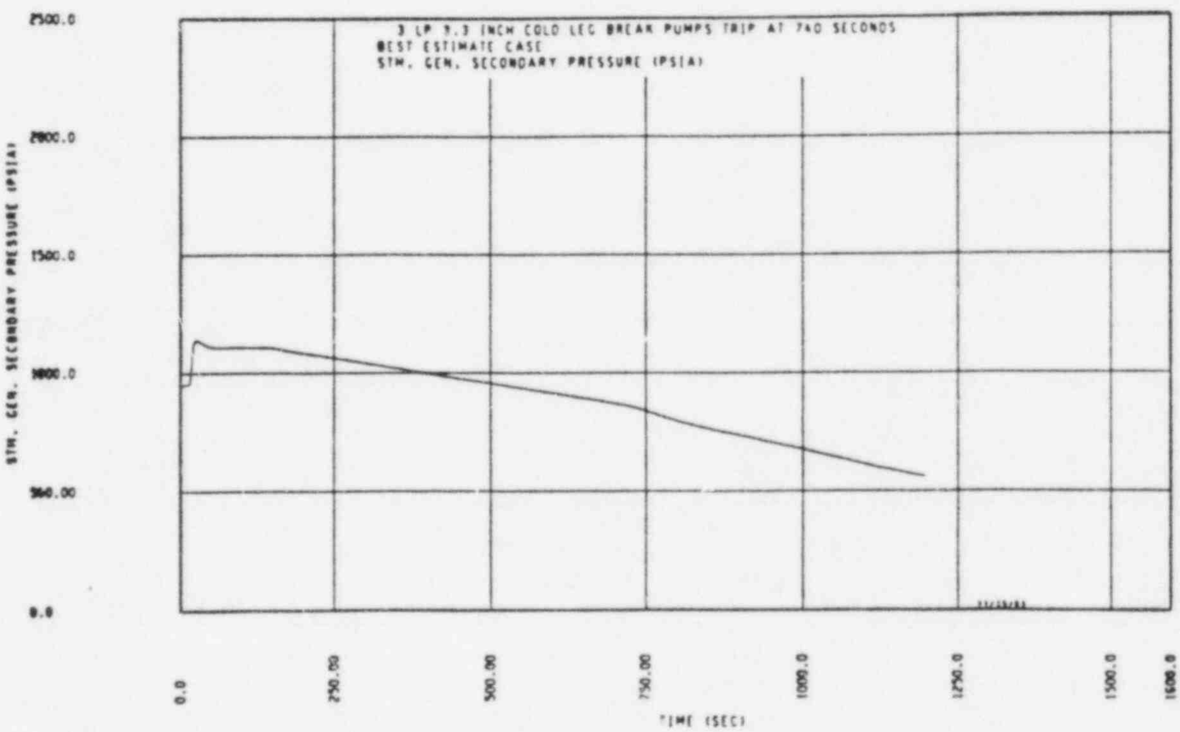


Figure 14 - SBLOCA Steam Generator Pressure (PSIA)

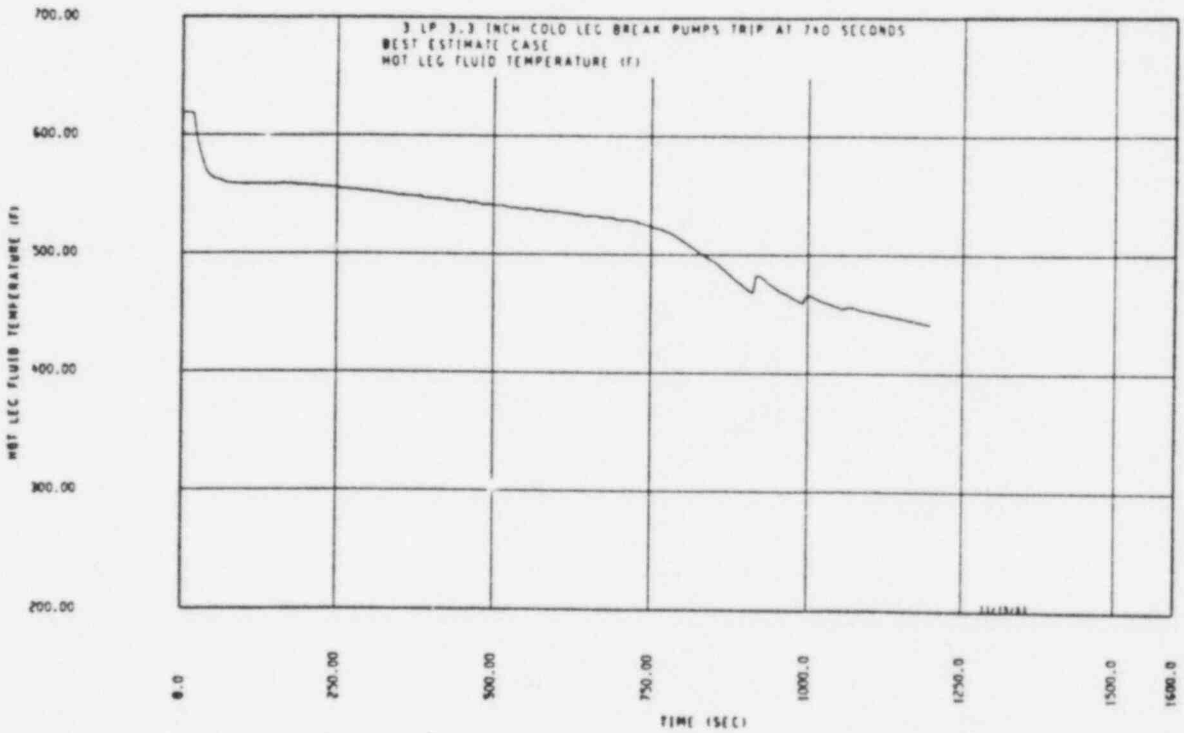


Figure 15 - SBLOCA Hot Leg Fluid Temperature (^{o}F)

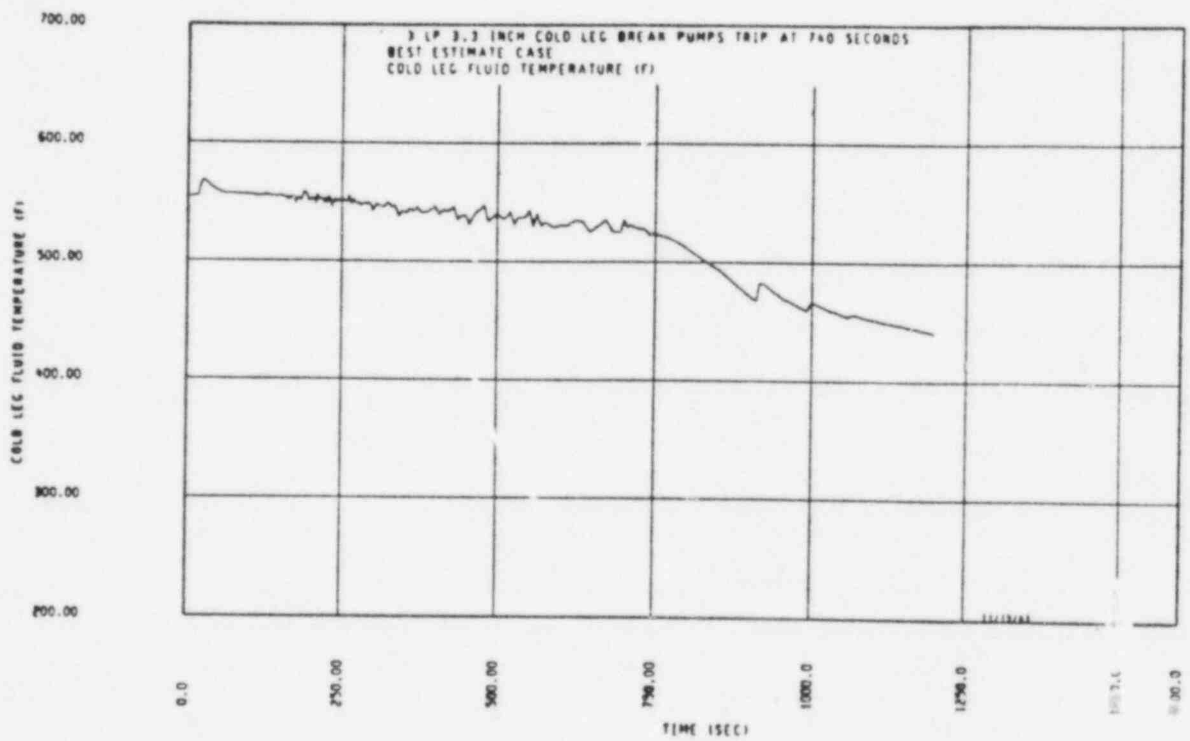


Figure 16 — SBLOCA Cold Leg Fluid Temperature (^{o}F)

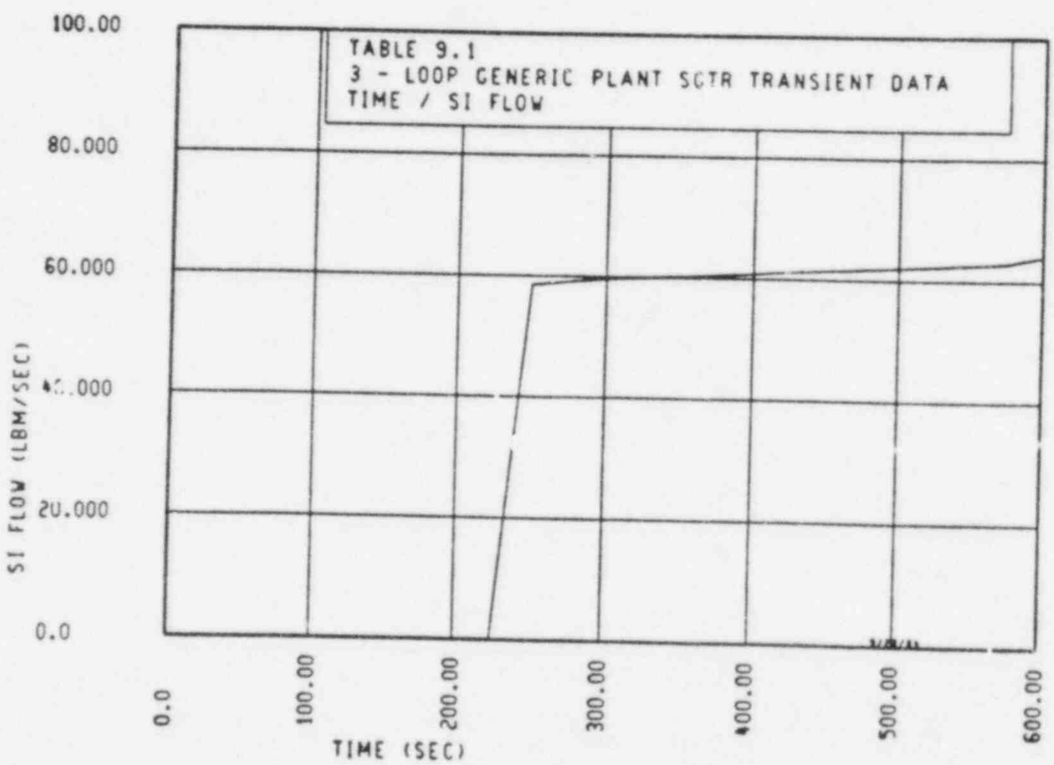


Figure 17 - Safety Injection Flow Rate (LBM/SEC)

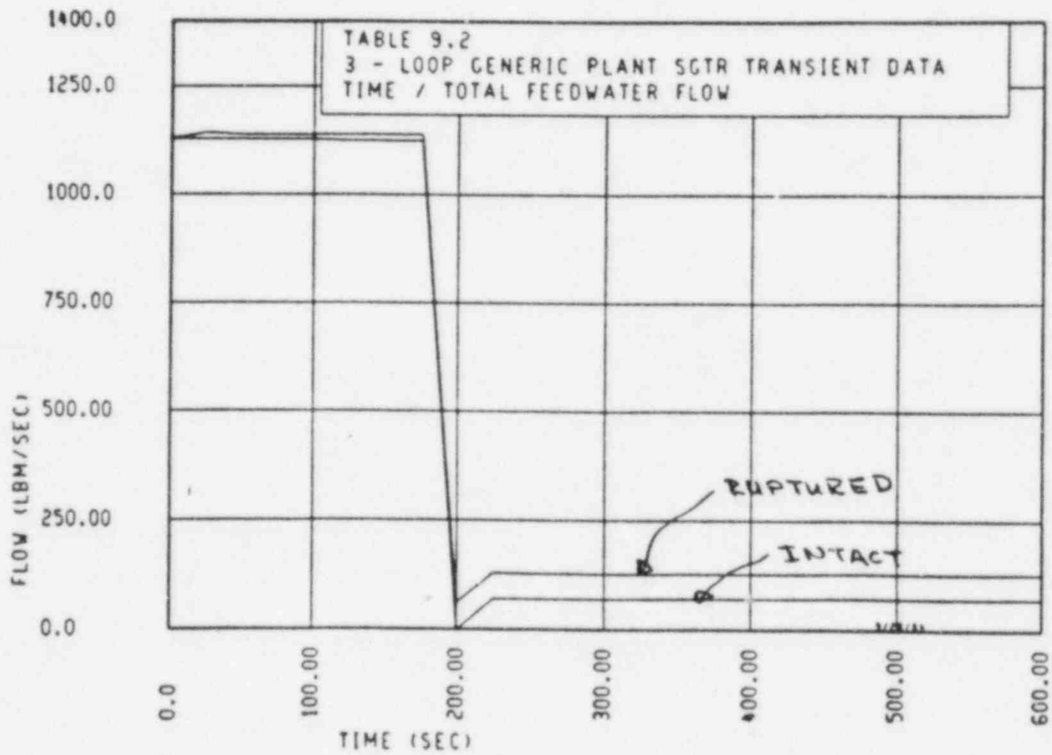


Figure 18 - Feedwater Flow (Ruptured + Intact Loop) (LBM/SEC)

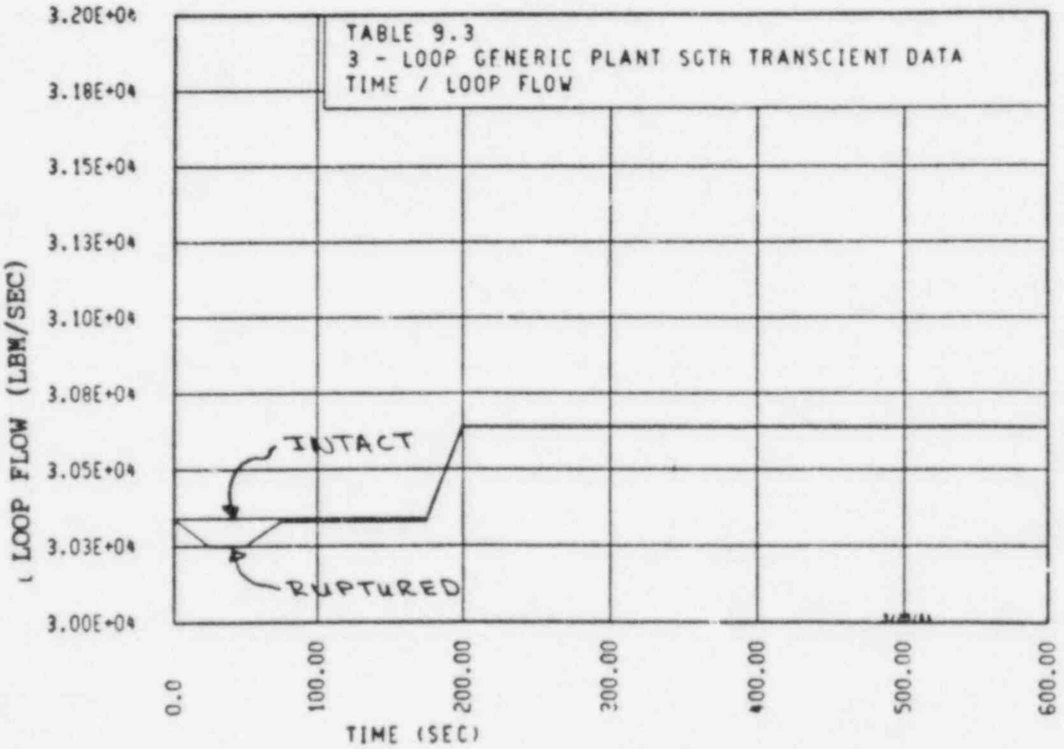


Figure 19 - RCS Loop Mass Flow Rate (Ruptured + Intact Loop) (LBM/SEC)

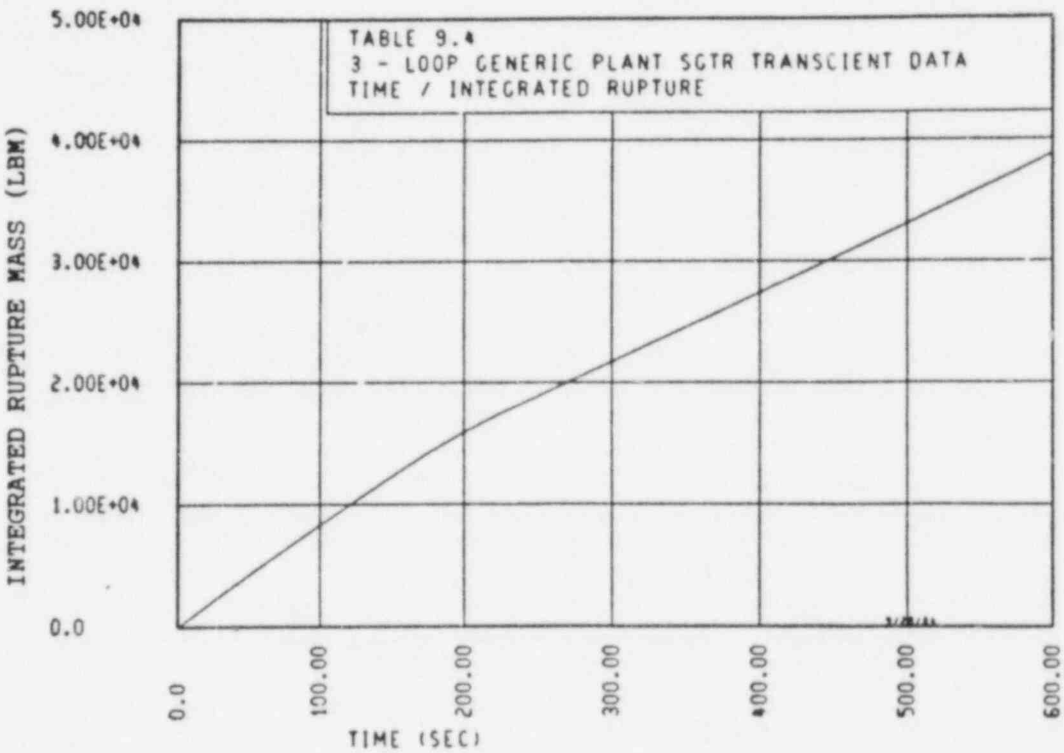


Figure 20 - Integrated SGTR Rupture Mass (LBM)

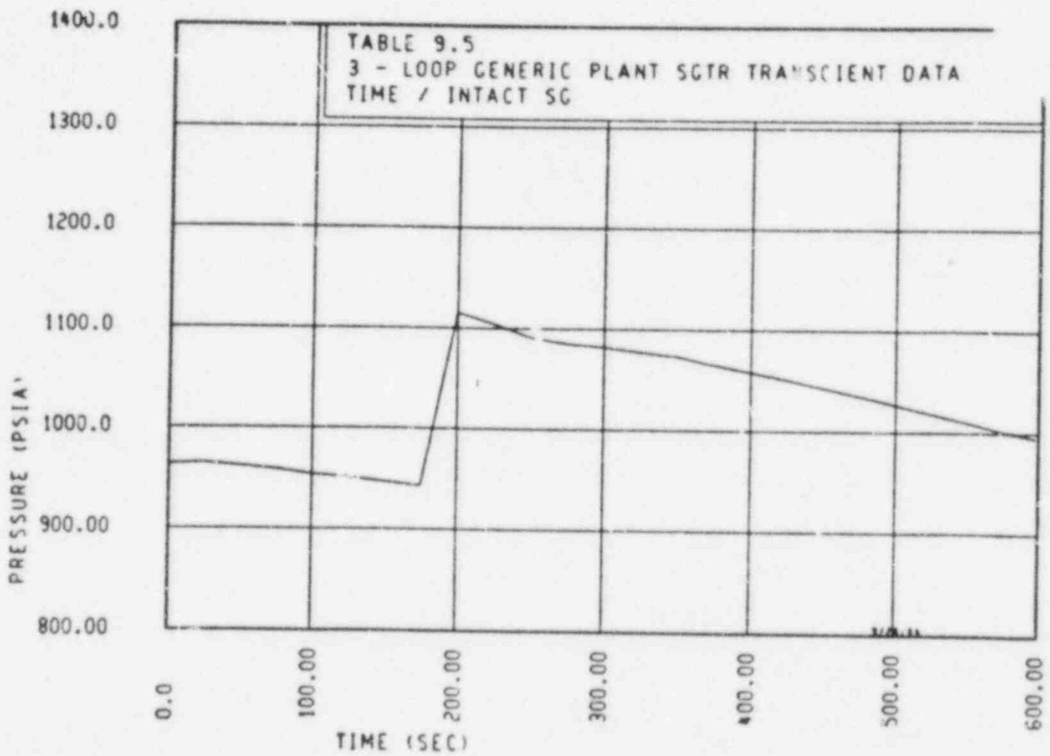


Figure 21 - Secondary Pressure (Intact Loop) (PSIA)

Q.74 What assumptions are used regarding charging pump flow for the SBLOCAs and SGTR events? Provide the charging-pump flow rate data in graphical or tabular form.

A.74 For the SGTR transients normal charging is flow not modeled in the analysis. However, the charging/SI flow is modeled and included in the SI flow curves for high pressure plants.

Normal charging flow is not modeled during a SBLOCA transient. However, charging flow following safety injection actuation is modeled; the rates were previously transmitted via reference 3 as the small break safety injection flow rates. Since only charging safety injection is modeled and no credit is taken for low head injection, the table in reference 3 is applicable.

References

1. Westinghouse Owners Group, "Evaluation of Alternate RCP Trip Criteria," Submitted to the NRC in response to NRC Generic Letters 83-10c and d WOG letter OG-110, December 1,1983.

2. Westinghouse Owners Group "Justification of Manual RCP Trip for Small Break Events," Submitted to the NRC in response to NRC Generic Letters 83-10c and d. WOG letter OG-117, March 9, 1984.

3. Westinghouse Letter NS-EPR-2918 to Mr. R. J. Mattson of the NRC dated May 24, 1984.

4. NRC Memorandum to Z. R. Rosztoczy (USNRC) from B. W. Sheron (USNRC), "Effect of Realistically - Estimated Accumulator Injection Behavior on Small Break Loss-Of-Coolant Accidents."