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TECHNOLOGIES

Integrated Nuclear Services

JHT/96-46
July 15, 1996

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

Subject: Supplementary Information to FTI's Response to NRC's Request for Additional Information on BAW-10168, Volume II, Revision 2, October 1992; RSG LOCA - BWNT Loss-of-Coolant Accident Evaluation Model for Recirculating Steam Generator Plants.

Reference: J. H. Taylor to Document Control Desk, "Response to NRC's Request for Additional Information on BAW-10168, Volume II, Revision 2, October 1992; RSG LOCA - BWNT Loss-of-Coolant Accident Evaluation Model for Recirculating Steam Generator Plants," JHT/94-171, October 28, 1994.

Gentleman:

The reference transmitted FTI's response to an NRC request for additional information on topical report BAW-10168, Revision 2. The attachment provides supplemental information to the referenced response. The material enclosed herein is considered non-proprietary to Framatome Technologies.

Very truly yours,

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Break Discharge Coefficients: For SBLOCA, the leak flow requirements of 10CFR50.46 Appendix K have generally been interpreted as use of the Moody discharge correlation with a C_d of 1.0 for the entire two-phase flow regime. However, In BAW-10168 Revision 1, Volume II, Section 4.3.2.4, FTI proposed the use of realistic break discharge coefficients for SBLOCA calculations. Comparisons between the Moody discharge correlation and experimental data show that Moody overpredicts the leak flow rate for void fractions of 70 percent (corresponds to a quality of 10 percent at a pressure of 1000 psi) or greater. To account for this deficiency and better predict system depressurization, FTI's method used a C_d of 0.7 for void fractions of 70 percent or greater. For subcooled, superheated, and saturated discharges up to void fractions of 70 percent, a C_d of 1.0 was still used. FTI's break discharge methodology was NRC-approved based on our qualitative evaluation of the approach and with a request for a quantitative evaluation before or with its first application. FTI provided the NRC-requested evaluations with and in response to requests for additional information on Revision 2 of BAW-10168, Volume II.

After consultation with NRC personnel, it became clear that FTI's discharge model, while having a sound technical basis, would be considered as non-standard, requiring a substantial additional licensing effort. We have concluded that the expenditure of such an effort would currently not be productive. In point of fact, for most SBLOCAs the use of either method would produce comparable trends and results, since little time is spent at leak void fractions where significant differences are noted between Moody and test data. Therefore, FTI is modifying its SBLOCA break flow model to reflect the common interpretation of Appendix K. A discharge coefficient of 1.0 will be used regardless of leak flow quality--subcooled, saturated, or superheated. Discharge correlations--Extended Henry-Fauske (subcooled), Moody (saturated), and Murdock-Bauman (superheated)--will remain unchanged. This, coupled with a break spectrum, complies with the intent and requirements of Appendix K for SBLOCA.

This switch in methodology will not invalidate the studies and benchmarks performed in support of Revision 2 nor will FTI totally abandon the use of its more accurate modeling technique. FTI will reanalyze SBLOCA cases having clad temperatures in excess of 1800 F using its variable C_d model. Reductions in the rate of system depressurization occurring during the "core boildown" (or high void phase of the transient), resulting from the use of the variable C_d method, can adversely impact ECC injection, core inventory, and possible lead to clad temperature increases above those predicted using the normal Appendix K technique. Analyzing high temperature SBLOCA transients using both Appendix K and our variable C_d methods will assure that the PCT is not underpredicted. SBLOCA transients below 1800 F are not highly susceptible to large clad temperature changes resulting from items such as the incidence of rupture and its accompanying inside/outside metal-water energy addition; the reverse becoming true as temperatures climb above 1800 F. At and above 1800 F, the energy contribution from the metal-water reaction is becoming increasingly significant. For those cases just below 1800 F, a reasonable safety margin of at least 400 F to the PCT criterion is provided. Hence, 1800 F is a logical transition point between analyzing a SBLOCA transient using only the Appendix K method and analyzing the case using both methods.

In summary, FTI will use a discharge coefficient of 1.0 for the entire two-phase leak flow regime. All other aspects of our break modeling will remain unchanged. This methodology complies with the intent and requirements of Appendix K for SBLOCA. For SBLOCA transients predicting clad temperatures above 1800 F using the Appendix K technique, FTI will also analyze such cases using its variable C_d method. 1800 F will be the established transition point. Analyzing such cases with both techniques assures that the PCT will be conservatively predicted.

Partial Loop Seal Clearing: In response to questions regarding partial loop seal clearing, several additional SBLOCA cases were run using the plant model shown in Figure 1. Break sizes were varied from 1.6 to 2.0-inch to study the transition from no loop seal clearing to the clearing of the broken loop. It was found that RELAP5/MOD2-B&W predicts this transition for breaks between 1.9 and 2.0-inches. The liquid levels in the broken loop pump suction piping for these two cases are shown in Figures 2 and 3. Figure 4 shows the core liquid levels for the two cases. From Figure 4 it can be observed that the minimum core liquid levels of about 9.0-ft occur at about 1600 seconds and increase thereafter. For the 2.0-inch break, the core liquid level is about 10.0-ft at the time of loop seal clearing. The loop seal spillunder elevation corresponds to 8.0-ft height from the bottom of the core.

The steam velocity in the upside pump suction piping for the 2-inch break is shown in Figure 5. Once the steam venting process initiates, the head imbalance in the loop seal accelerates the steam flow and can be expected to reach a terminal velocity sufficient to clear the loop seal. For the 2-inch beak the terminal steam velocity in the upside pump suction piping reaches about 10.0 ft/s at the time of loop seal clearing as shown in Figure 5. Tuomisto and Kajanto[1] show that the loop will clear completely for steam velocity greater than 6.2 ft/s (1.9 m/s) at 870 psia (60 bar). This is based on the flooding criterion for large diameter vertical pipes, Kutateladze Number Ku (See Equation 5 in Reference 1) equals 3.2. This flooding criterion is defined as a zero downward flow of falling film on the tube surfaces. They also show that, at pressures above about 145 psia (10 bar), vertical flooding is the limiting mechanism for loop seal clearing rather than the droplet entrainment from the stratified liquid in the horizontal section of the loop seal. For the 2.0-inch break case, the system pressure is about 1000 psia and therefore the loop will clear for steam velocities lower than 6.2 ft/s. The 1.9-inch break case in ROSA (see response to Question 14) demonstrates the loop seal clearing mechanism discussed above. For these break sizes, it is possible to accumulate some of the liquid in the loop seal once the initial acceleration of steam is complete as observed in the test. This liquid fall back is also observed in the RELAP5 simulation of the 1.95-inch break case which is discussed at the end of this section.

Figure 3 shows that the liquid level in the upside of the loop seal section starts to decrease after about 1700 seconds. The void fractions in Nodes 255, 260, and 265 are shown in Figures 6 through 8, respectively. From these figures it can be seen that the liquid level decrease in the loop seal upside section is caused by the increase in void fraction in the pump volume (Node 260). Steam venting from the loop seal occurs only after about 2200 seconds as shown in Figure 6. The pump discharge piping on the other hand is highly voided after about 750 seconds due to the steam flow from the upper head spray nozzles into the downcomer. At about 1600 seconds the break junction void fraction increases rapidly from zero to a highly voided state and the flow in the cold

leg starts to oscillate. Injection of the cold ECC water into the highly voided cold leg and the break node amplify these oscillations. This results in a flow of steam from the cold leg into the pump volume. Note that in the broken loop, up until loop seal clearing, the HPI water is injected in to the Node 276 (a vertical node), and the CCI water is injected into the cold leg. The equilibrium option is selected in Node 276, making Node 276 a major source of oscillations. Stratified flow is expected in the pump discharge piping and RELAP5 allows only small condensation when the flow is stratified. The voiding of the pump node prior to loop seal clearing is discussed further in the next section.

To further study the possibility of predicting partial loop seal clearing, a 1.95-inch break case was run. The broken loop also cleared for this case. However, some liquid remained in the upside section and in the pump node, possibly as a liquid film on the pipe walls that fell back after the high steam flow period ended. This water eventually accumulated in Node 255 as shown in Figure 9. All other nodes in the loop seal were almost completely voided. The liquid did not fall into node 250, which represents the lowermost portion of the U-bend. This is consistent with the discussion in Reference 1.

<u>Pump Noding Sensitivity Study</u>

The broken loop pump suction noding for the base model is shown in Figure 10. To reduce early loop seal clearing, Node 248, representing the lower portion of the downside piping, was set at a small node height, 1 foot. The bottom of Node 248 coincides with the spill under elevation of the loop seal. Node 250 represents the horizontal portion of the U-bend and the height of this node is the radius of the pipe. Node 260 represents the pump. The height of Node 260 is 5.81 ft which is the actual height of the pump up to the centerline of the discharge piping. In RELAP5, the pump volume also uses the high mixing flow regime, and, therefore, slug flow (Wilson drag) is not used in this node, even though it is a vertical node.

The early voiding of the pump node for the 2.0-inch break case, as discussed in the previous section, may have been caused by the height of Node 260. To study the sensitivity of pump node size, the base input model was modified by dividing the pump volume into three nodes (259-1, 259-2, and 260) as shown in Figure 11. Node 260 still represents the pump. In this case the 2.0-inch break case did not clear the loop seal. For a 2.1-inch break case, the loop seal cleared after about 3300 seconds. Collapsed liquid levels in the loop seal and core and the void fractions in the loop seal nodes, pump node, and the pump discharge node of the broken loop are shown in Figures 12 through 22. From these figures the following observations can be made. Steam venting through the loop seal starts after Node 245 is highly voided. This occurs at about 1400 seconds. The void fraction in Node 259-1, which is part of the actual pump, is close to the void fraction in Node 258. Node 260 is highly voided and the void fraction in node 259-2 is somewhere between the values for Nodes 259-1 and 260. The void distribution in the upside U-bend, including the pump volume, is improved over that in the base calculation. The venting of steam causes the liquid level in the upside of the U-bend to decrease, reducing the core level depression. Figures 12, 14, and 15 show liquid level oscillations on the order of 1.0 foot in the down side of the U-bend from about 1500 seconds until the time of loop seal clearing, about 3300 seconds. The oscillations are mainly caused by the condensation of steam on the cold ECC water

injected into the cold legs. Rothe, Wallis, and Thrall[2] discussed the pressure and flow oscillations due to the condensation of steam on ECC water in the cold legs. CE[3] and Westinghouse 1/14 scale tests[2] (See Table X in Reference 2) both show condensation induced pressure oscillations on the order of 10 to 20 psi. Therefore, the RELAP5 calculated 1.0 foot oscillations are reasonable.

Conclusion

From this study the following conclusions are made. The transition from no loop seal clearing to clearing of one loop occurs within a narrow range of break sizes. Condensation-induced oscillations causes steam venting through the loop seal before the liquid level in the downside section of the loop seal reaches the spillunder elevation. This substantially reduces the possibility of core uncovery at the time of loop seal clearing for these break sizes. The core never uncoverd for the break sizes studied here.

The revised pump noding will be used in SBLOCA EM. However, this model change does not impact previous EM studies and benchmarks.

References

1. H. Tuomisto and P. Kajanto, "Two-Phase Flow in a Full Scale Facility," Nuc. Engg. And Design 107, pp 295-305, 1988.

2. P. H. Rothe, G. B. Wallis, and D. E. Thrall, Cold Leg ECC Flow Oscillations, EPRI NP-282, November 1976.

3. W. E. Burchill, P. A. Lowe, and J. R. Brodrik, Steam-Water Mixing Test program Task D: Formal Report for Task B and Final Report for the Steam Relief Phases of the Test Program, CENPD-101, AEC-C00-2244-1, October 1973.

Proprietary

Figure 5.9-2
RELAP5 Small Break LOCA Model
Sequoyah Noding for Primary Loops with Model 51 SGs

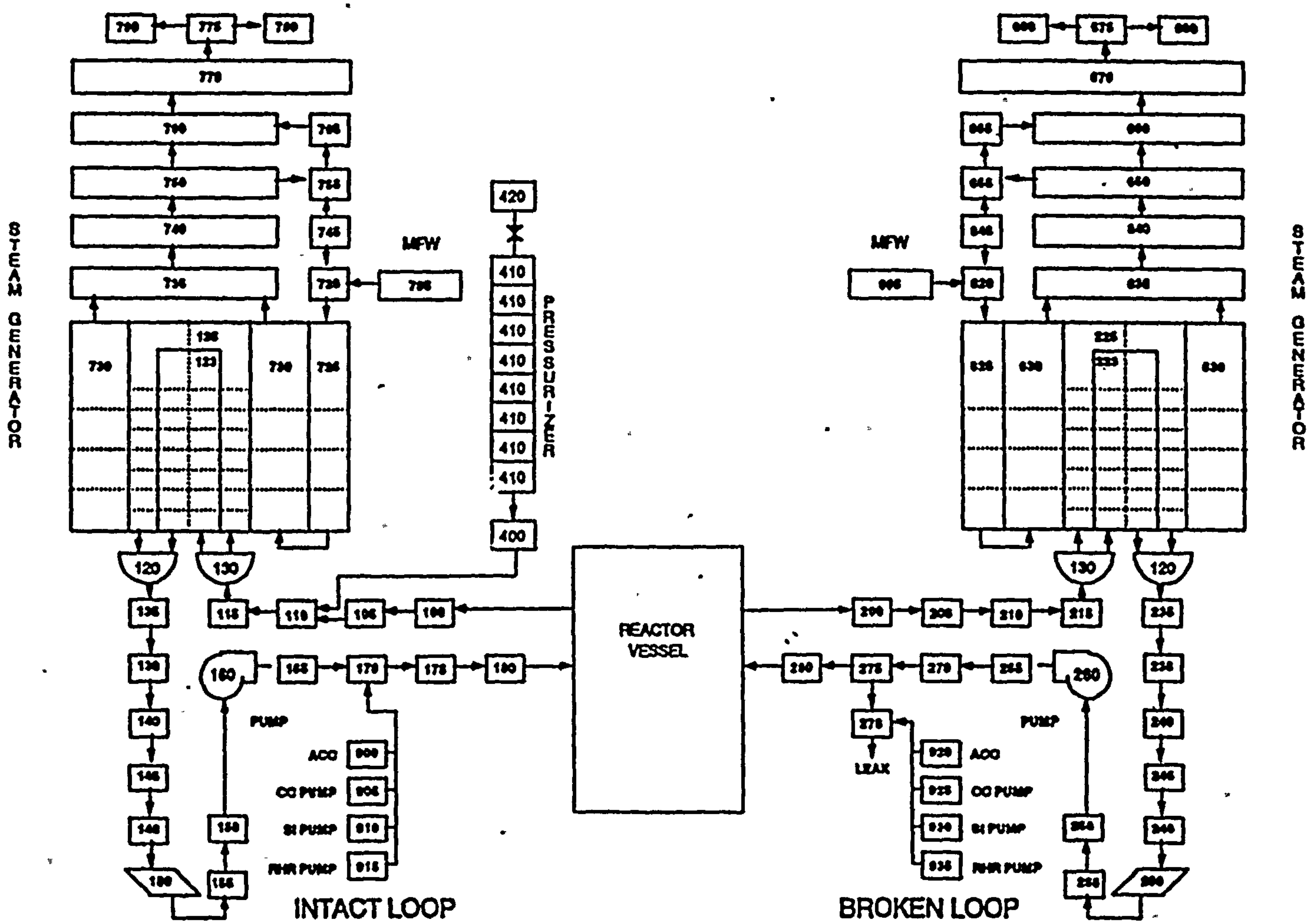


Fig-1

5

Fig 1

R5/2 1.9 INC BREAK
RELAP5/MOD2 Ver 20.0HP

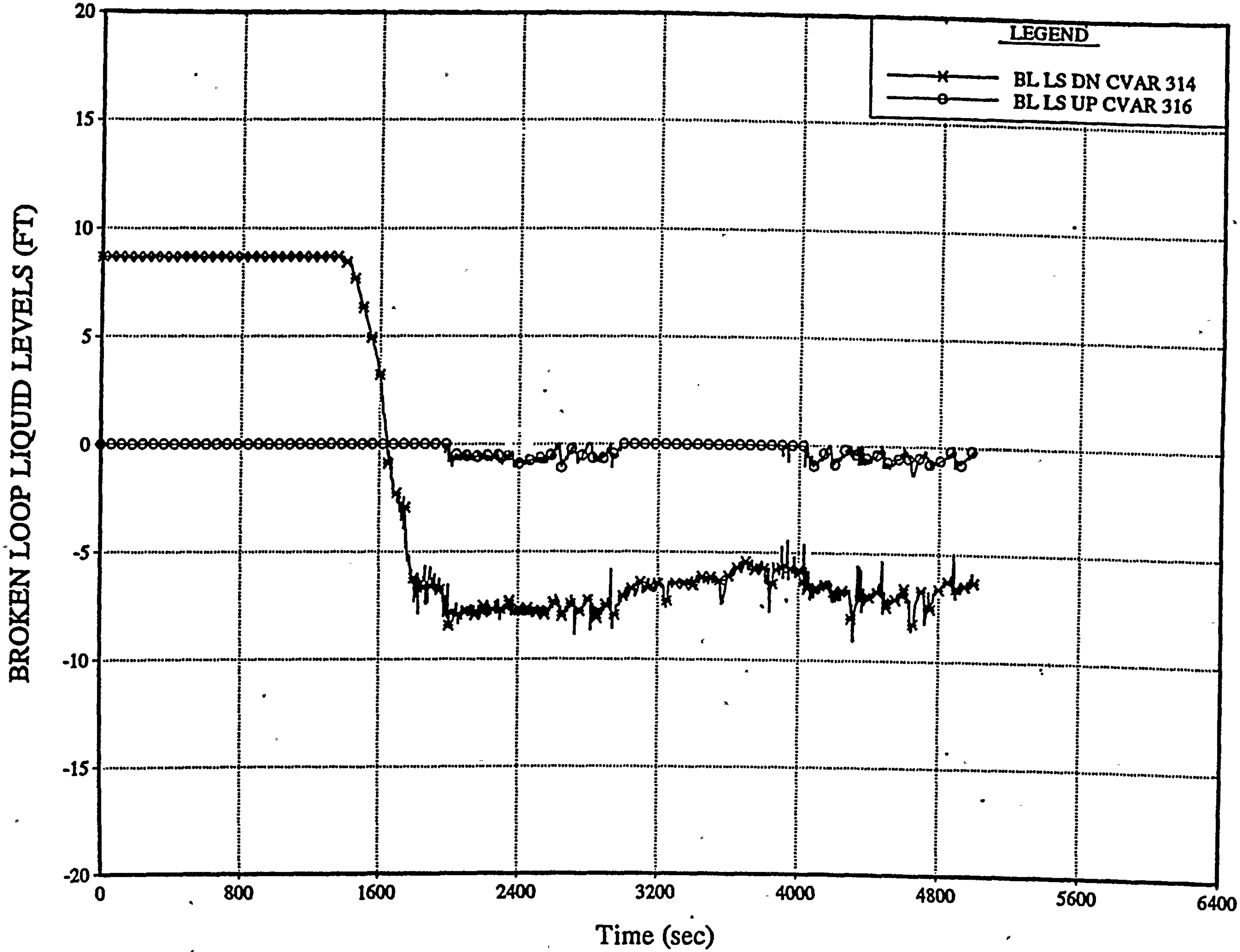


Fig-2

Fig2

R5/2 2.0 &4.0 INCH PD BREAKS
RELAP5/MOD2 Ver 20.0HP

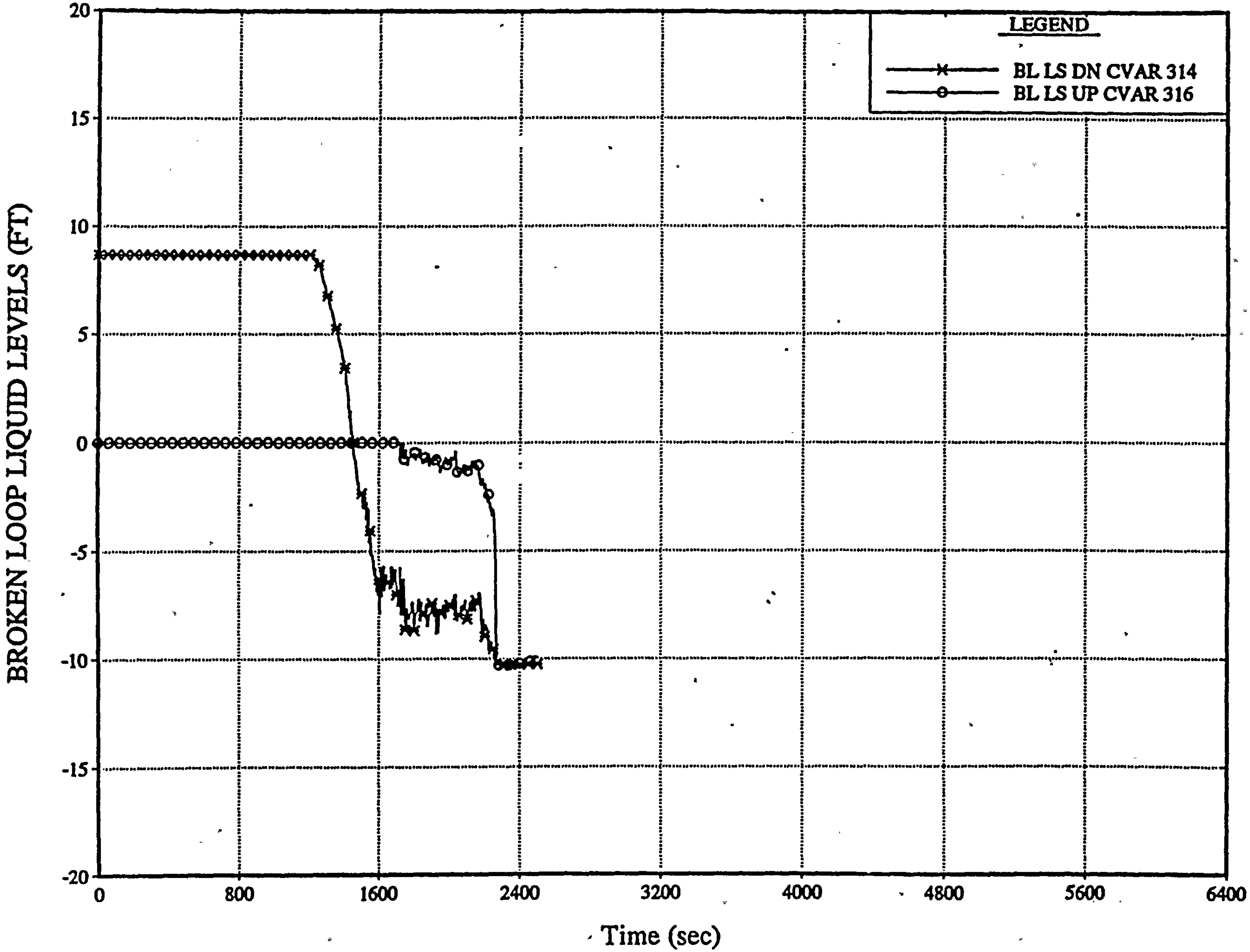


Fig-3

Fig 3

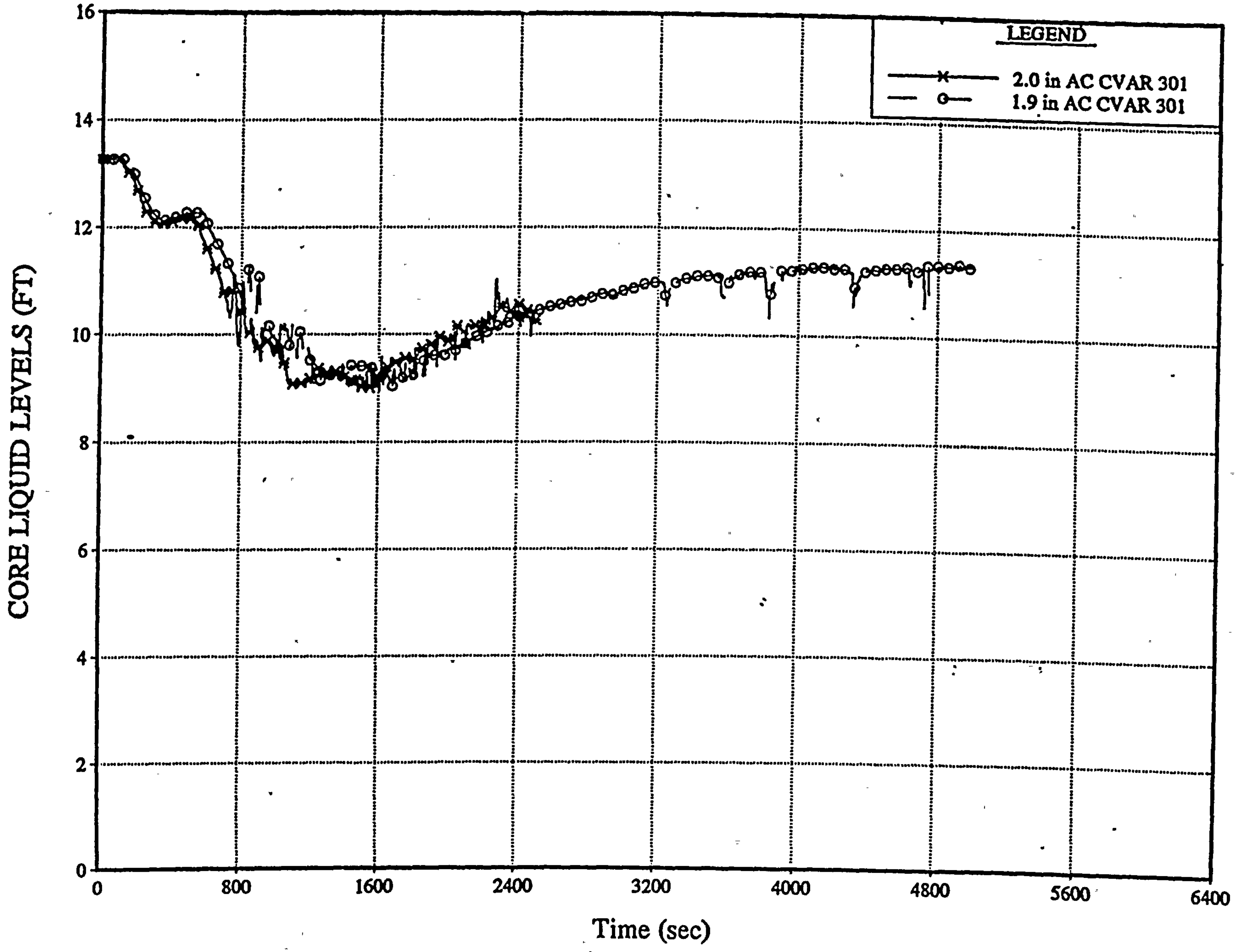
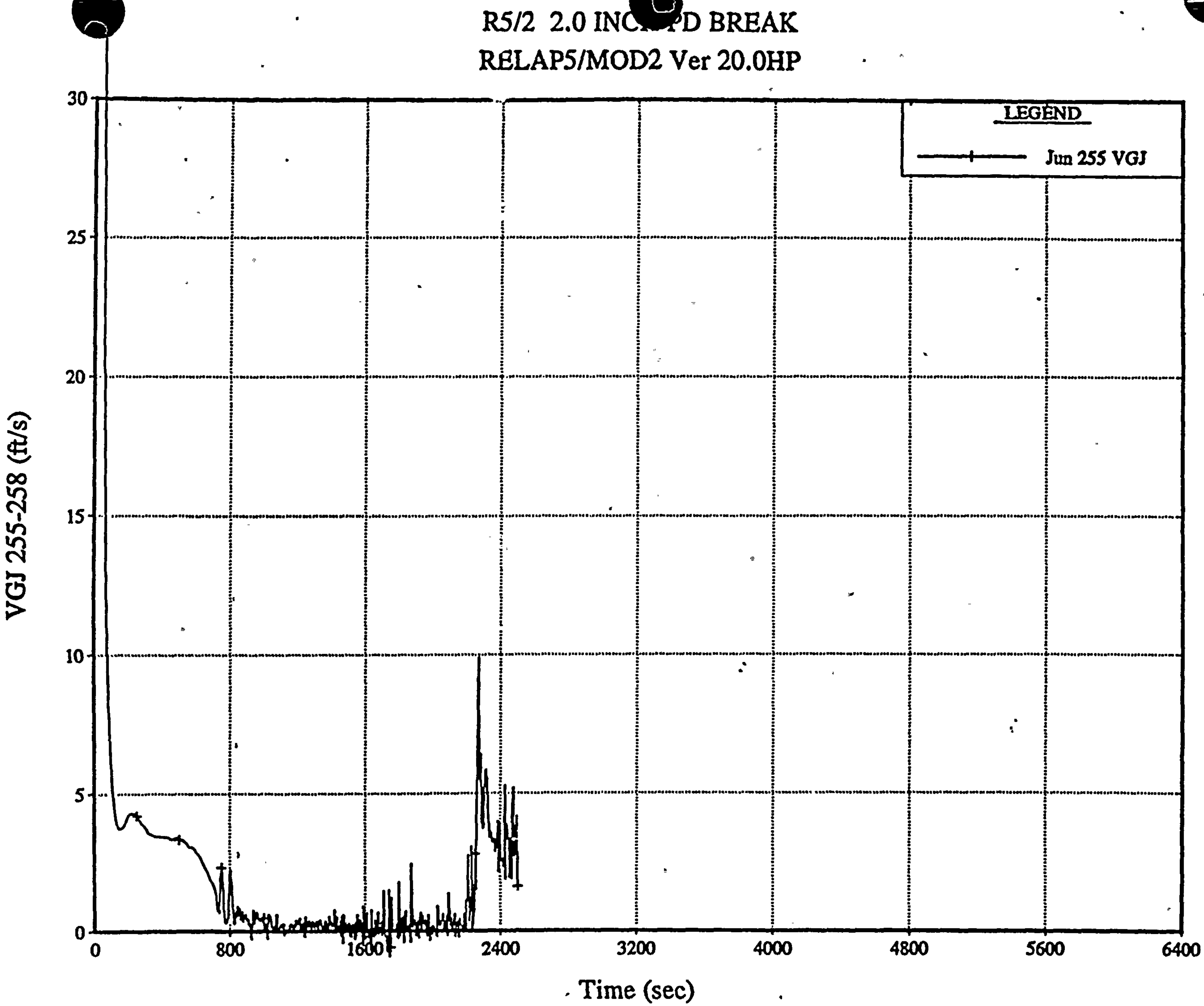

R5/2 2.0 & 1.9 IN PD BREAKS
RELAP5/MOD2 Ver 20.0HP
LEGEND
2.0 in AC CVAR 301
1.9 in AC CVAR 301
CORE LIQUID LEVELS (FT)
Time (sec)
0
2
4
6
8
10
12
14
16
800
1600
2400
3200
4000
4800
5600
6400

Fig 4

F-15-4



R5/2 2.0 INC PD BREAK
RELAP5/MOD2 Ver 20.0HP
LEGEND
Jun 255 VGJ
VGJ 255-258 (ft/s)
Time (sec)
0
5
10
15
20
25
30
0
800
1600
2400
3200
4000
4800
5600
6400

Fig - 5

FIG 5

SQN 2.0 in SBLO Case, sqnsb2b.in

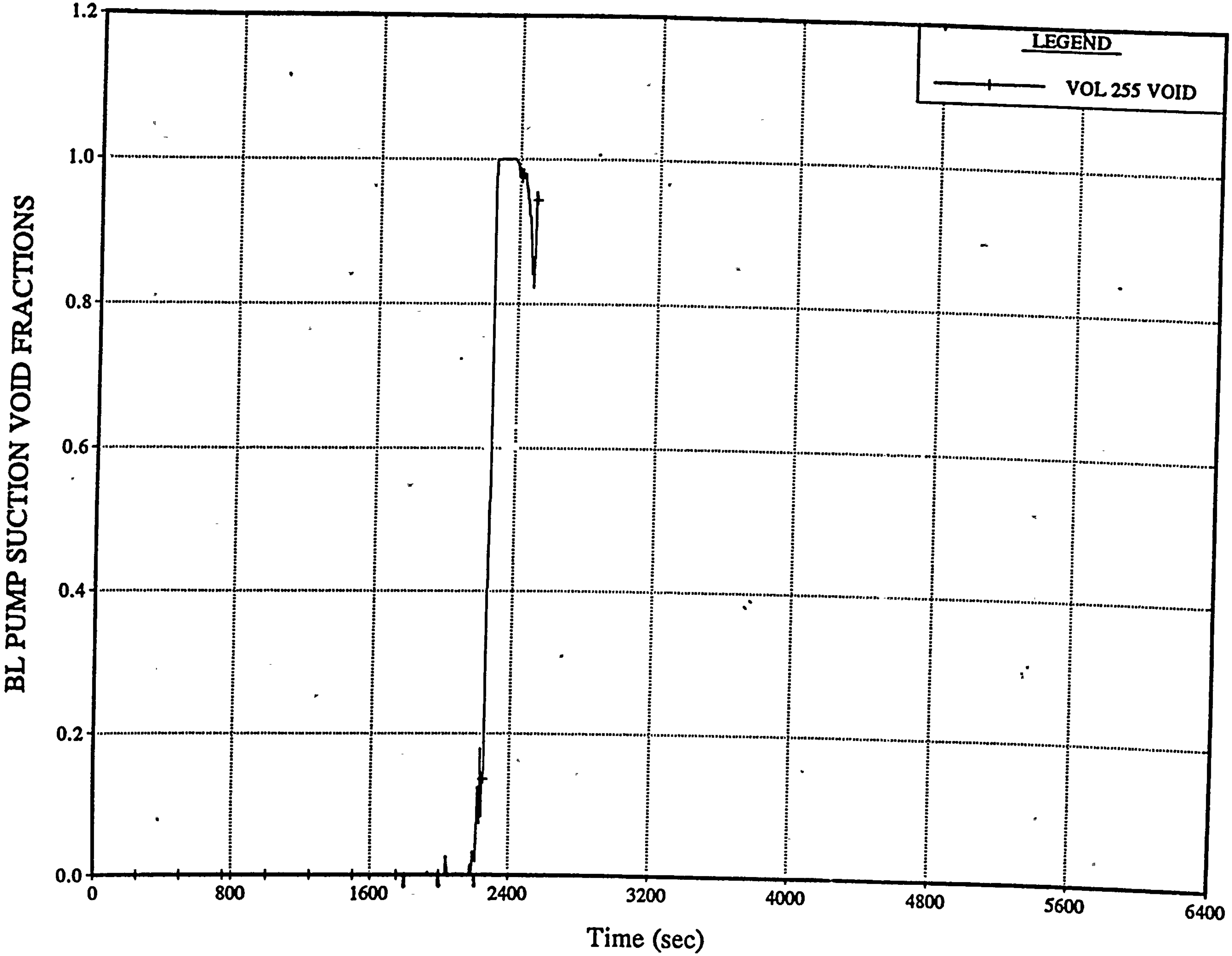


Fig 6

10 Fig - 6

SQN 2.0 in SBLOCA Case, sqnsb2b.in

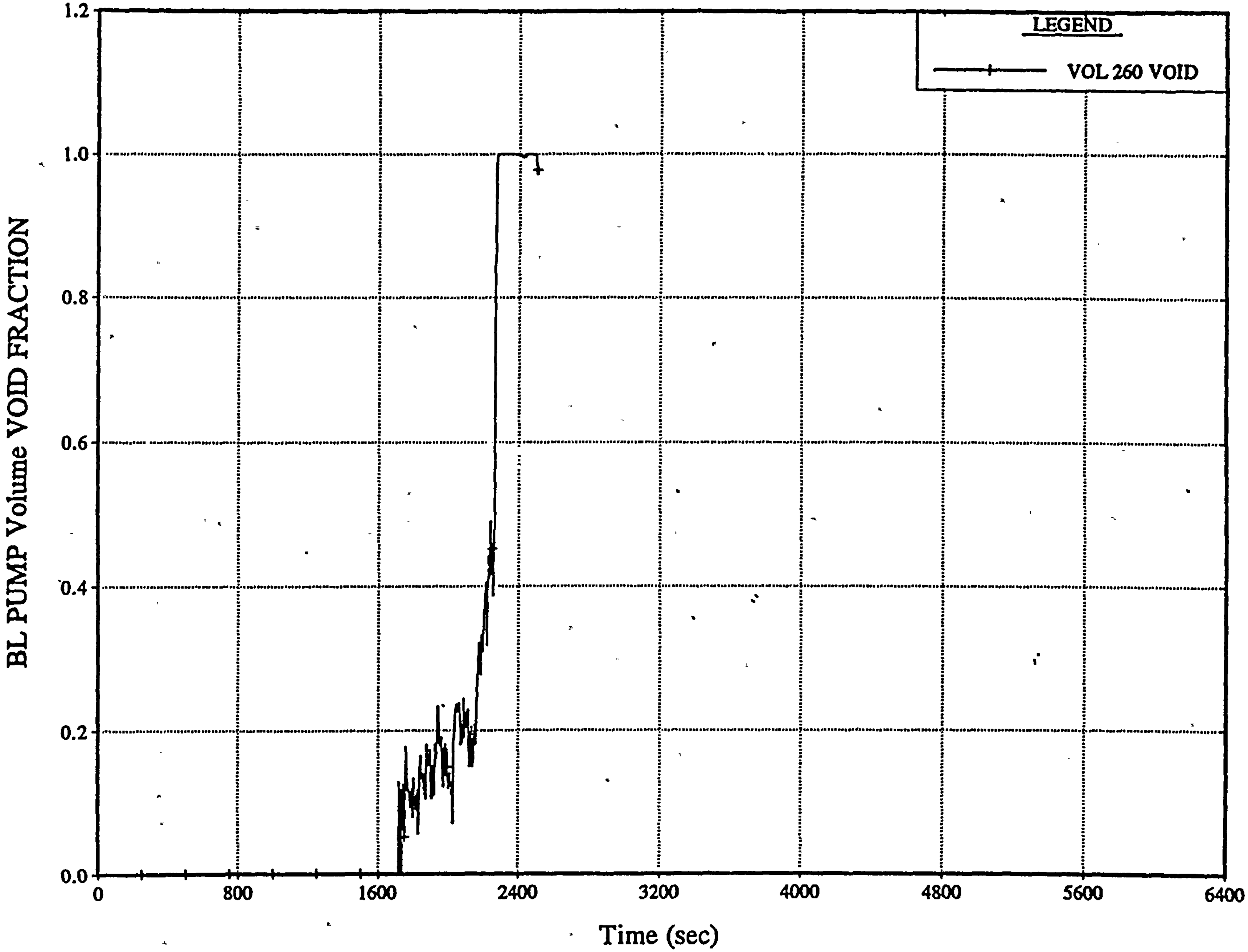


Fig - 7

Fig 7

SQN 2.0 in SBLOCA Case, sqnsb2b.in

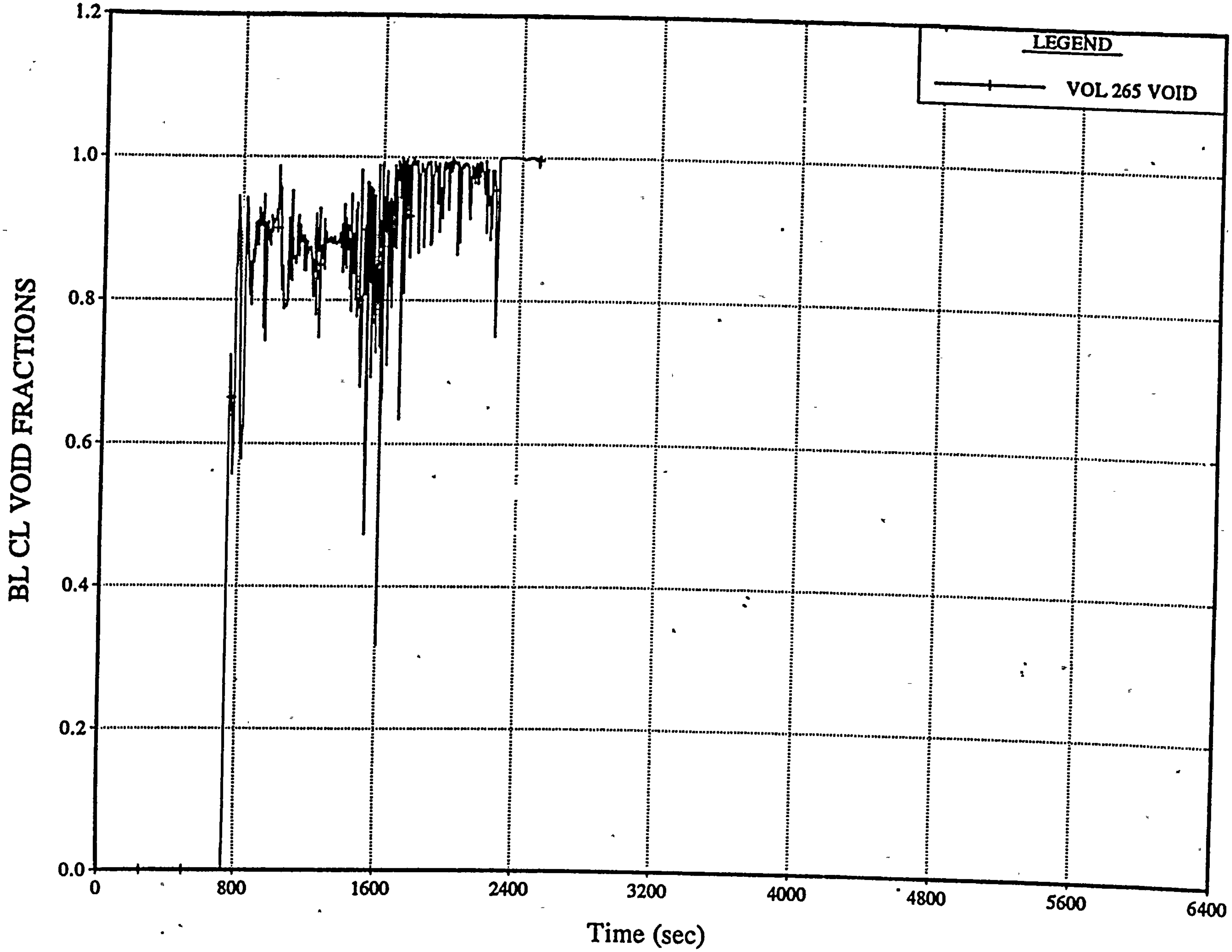


Fig - 8

12

Fig 8

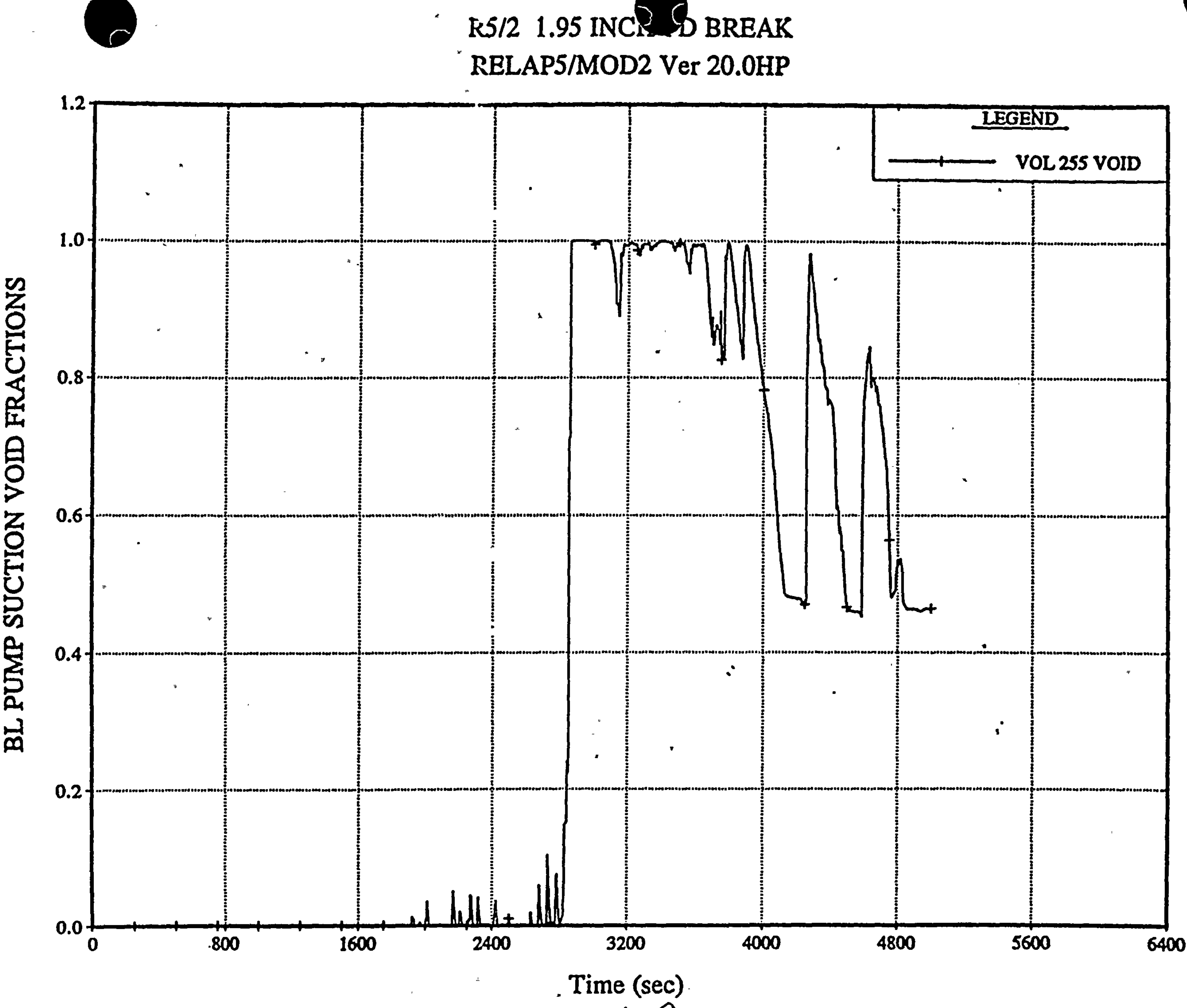

R5/2 1.95 INCH [illegible]D BREAK
RELAP5/MOD2 Ver 20.0HP
LEGEND
VOL 255 VOID
BL PUMP SUCTION VOID FRACTIONS
1.2
1.0
0.8
0.6
0.4
0.2
0.0
0
800
1600
2400
3200
4000
4800
5600
6400
Time (sec)

Fig 9

13 Fig-9

Figure 10: Typical FTI SBLOCA 4-Loop RSG Pump Suction Noding Details

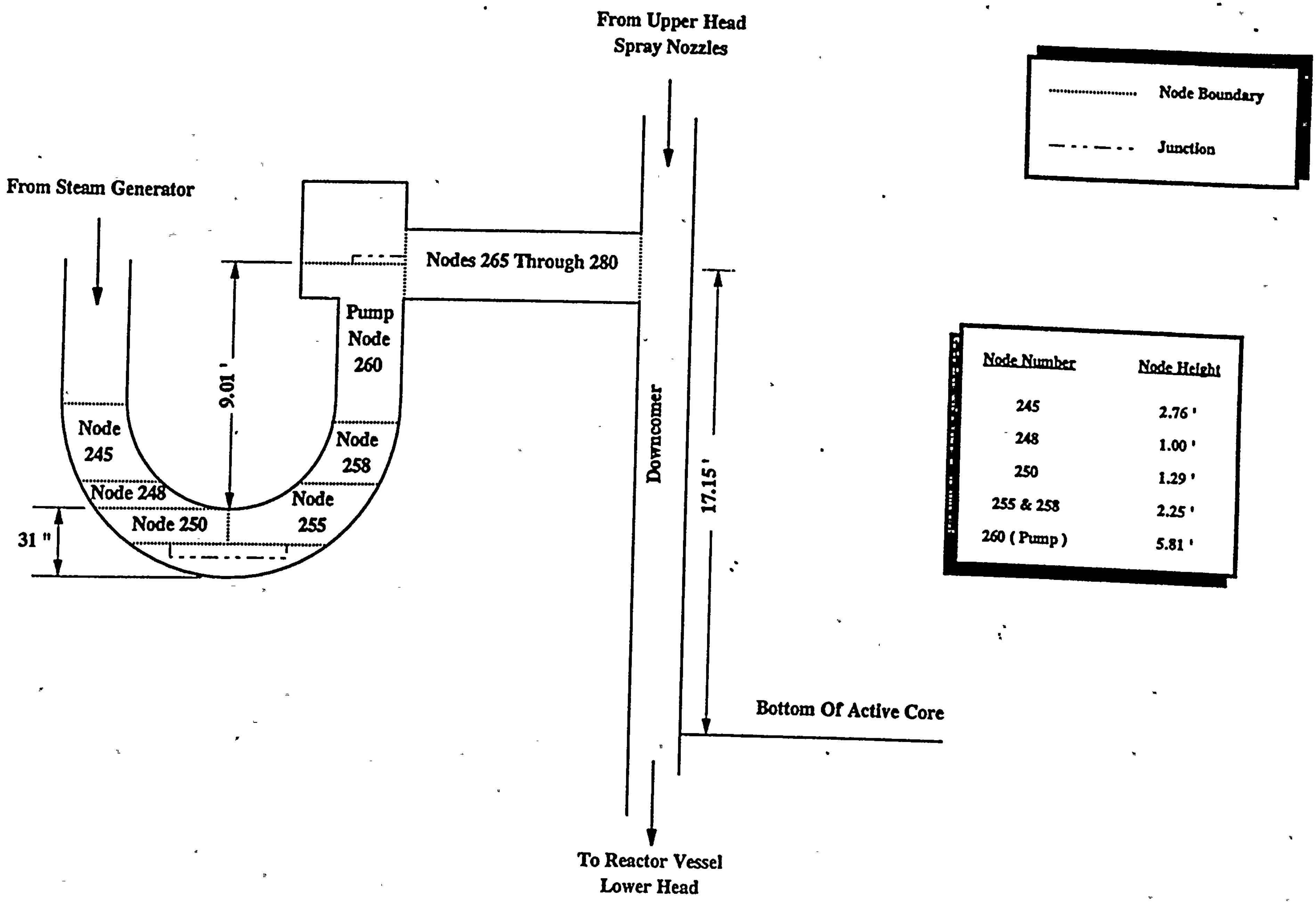


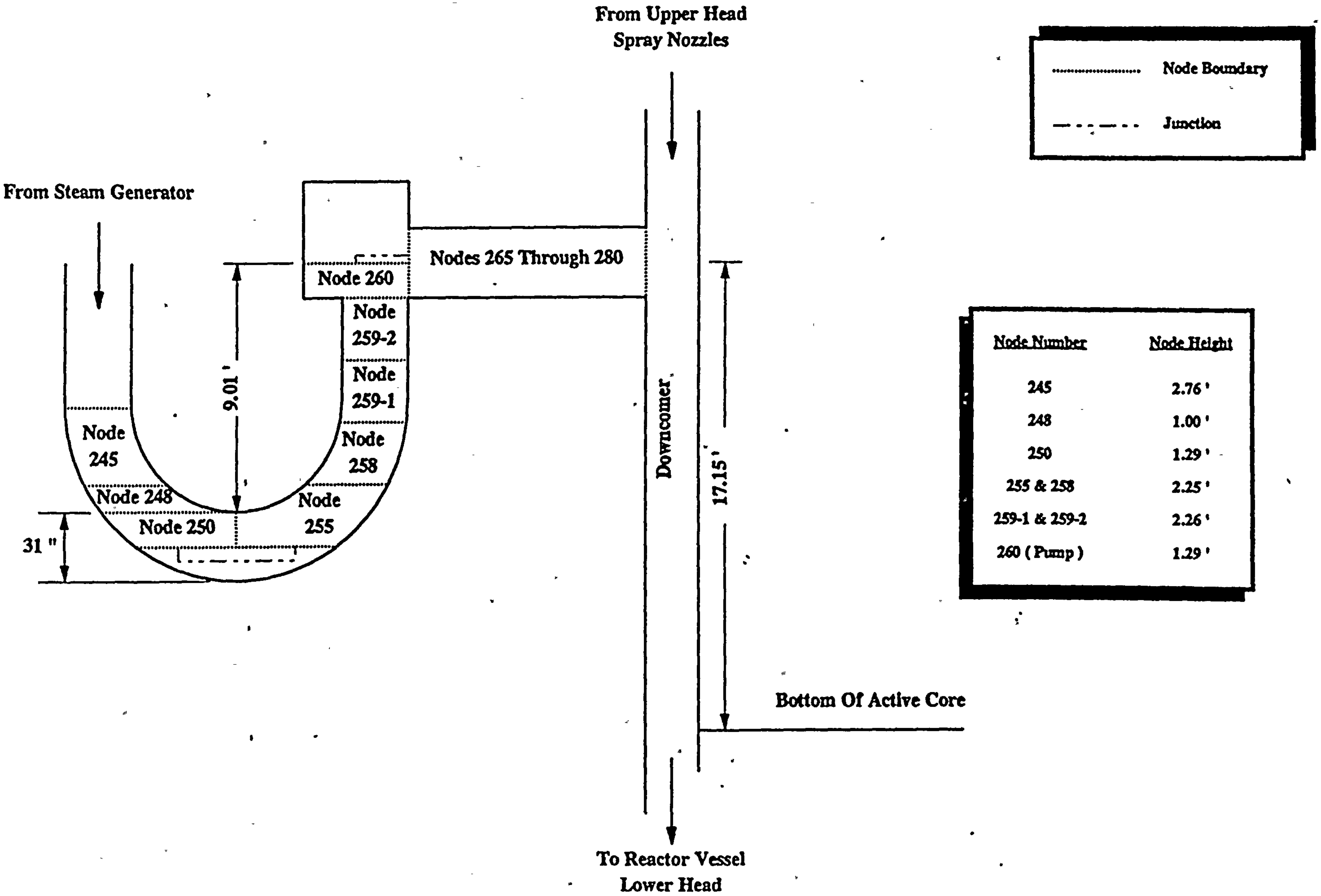
Fig-10

14

Fig-11

15

Figure 11: Revised FTI SBLOCA 4-Loop RSG Pump Suction Noding Details



Node Number	Node Height
245	2.76 '
248	1.00 '
250	1.29 '
255 & 258	2.25 '
259-1 & 259-2	2.26 '
260 (Pump)	1.29 '

R5/2 2.1 INCH PD BREA[illegible]lit BL Pump Vol 260
RELAP5/MOD2 Ver 20.0HP

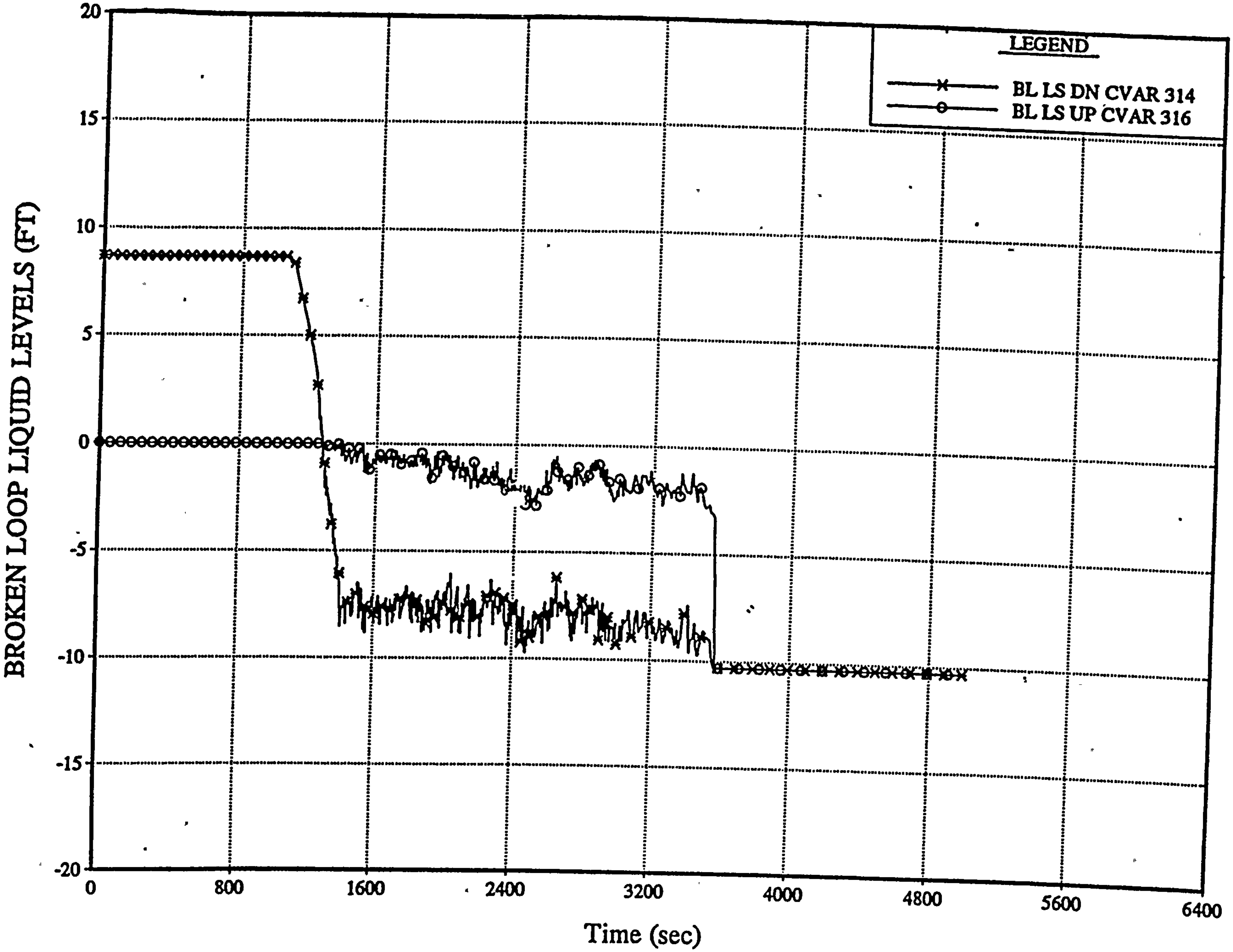


Fig 12

Fig-12

TATB VWRO CNTRL040

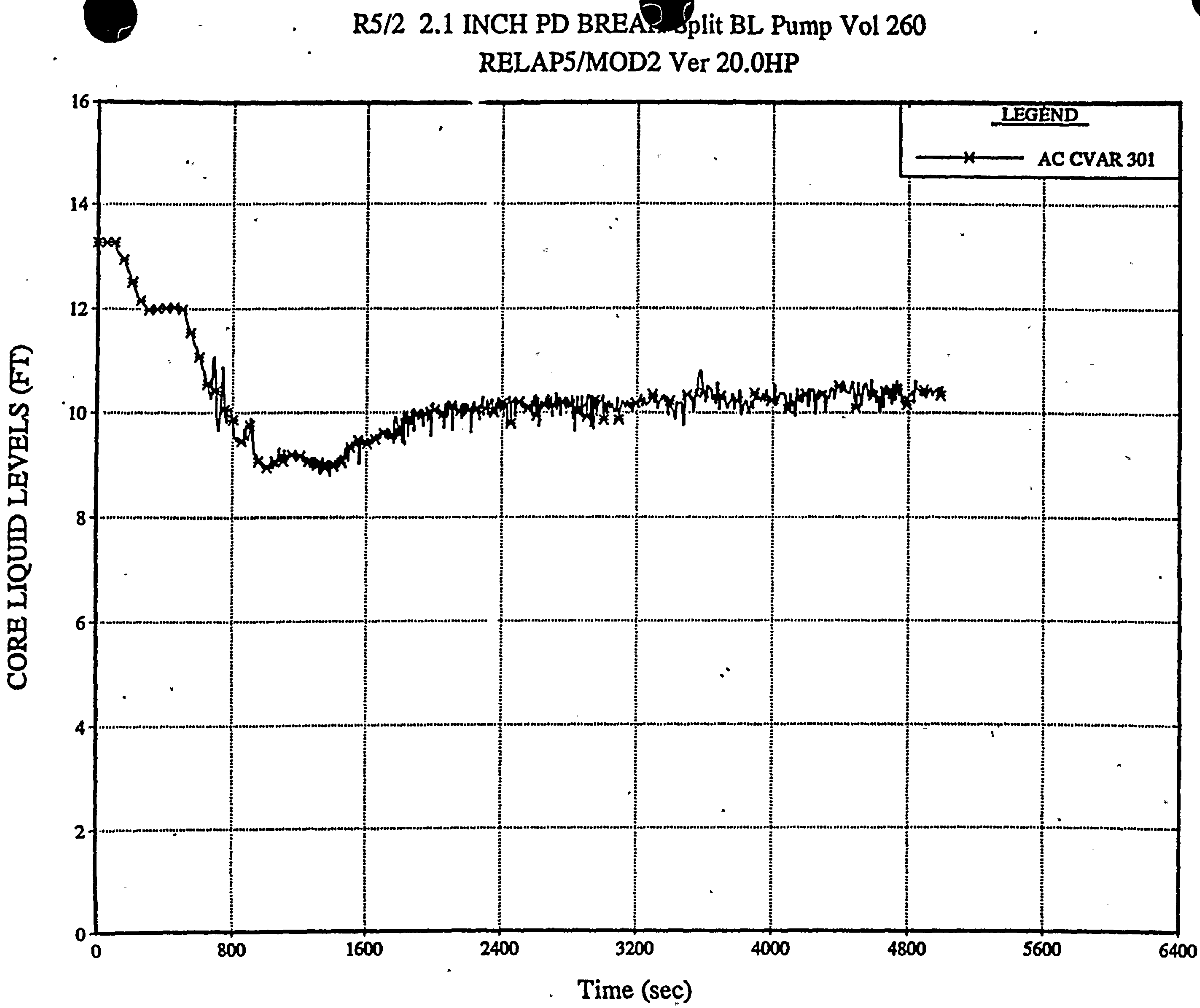


Fig-13

17

Fig 13

R5/2 2.1 INCH PD BREAK [illegible]it BL Pump Vol 260
RELAP5/MOD2 Ver 20.0HP

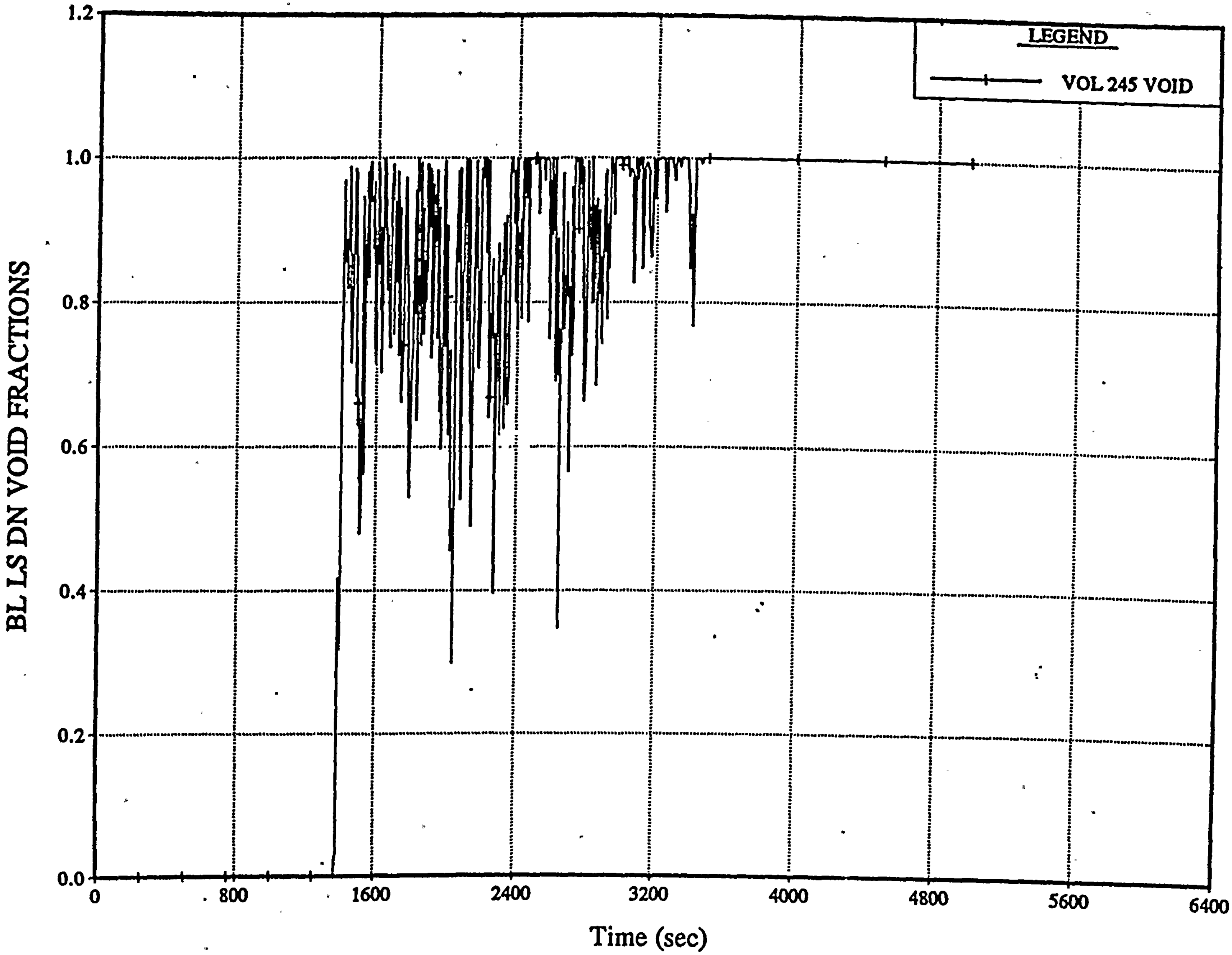
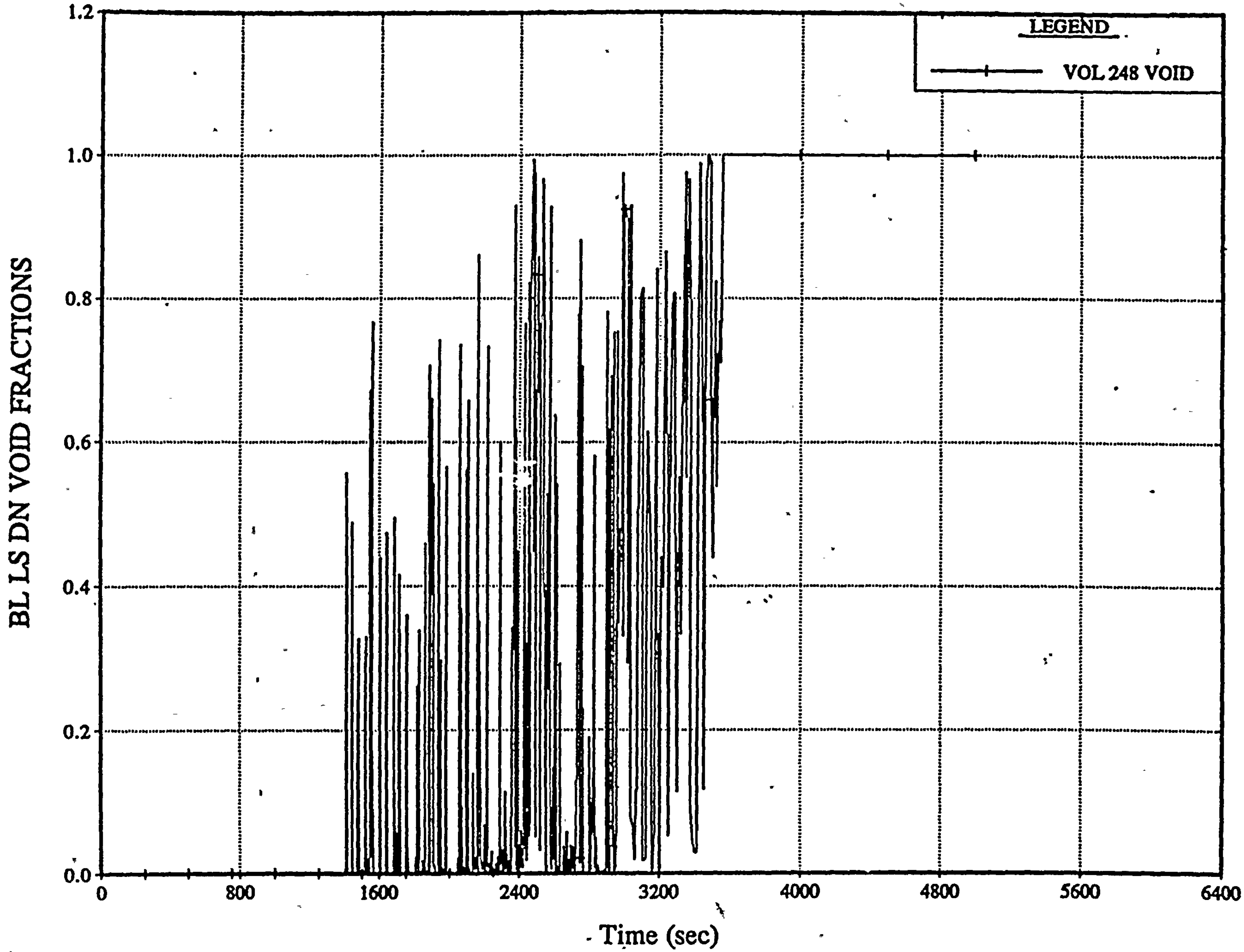


Fig 14

R5/2 2.1 INCH PD BREAK Split BL Pump Vol 260
RELAP5/MOD2 Ver 20.0HP



F19-15

Fig 15

R5/2 2.1 INCH PD BREAK Split BL Pump Vol 260
RELAP5/MOD2 Ver 20.0HP

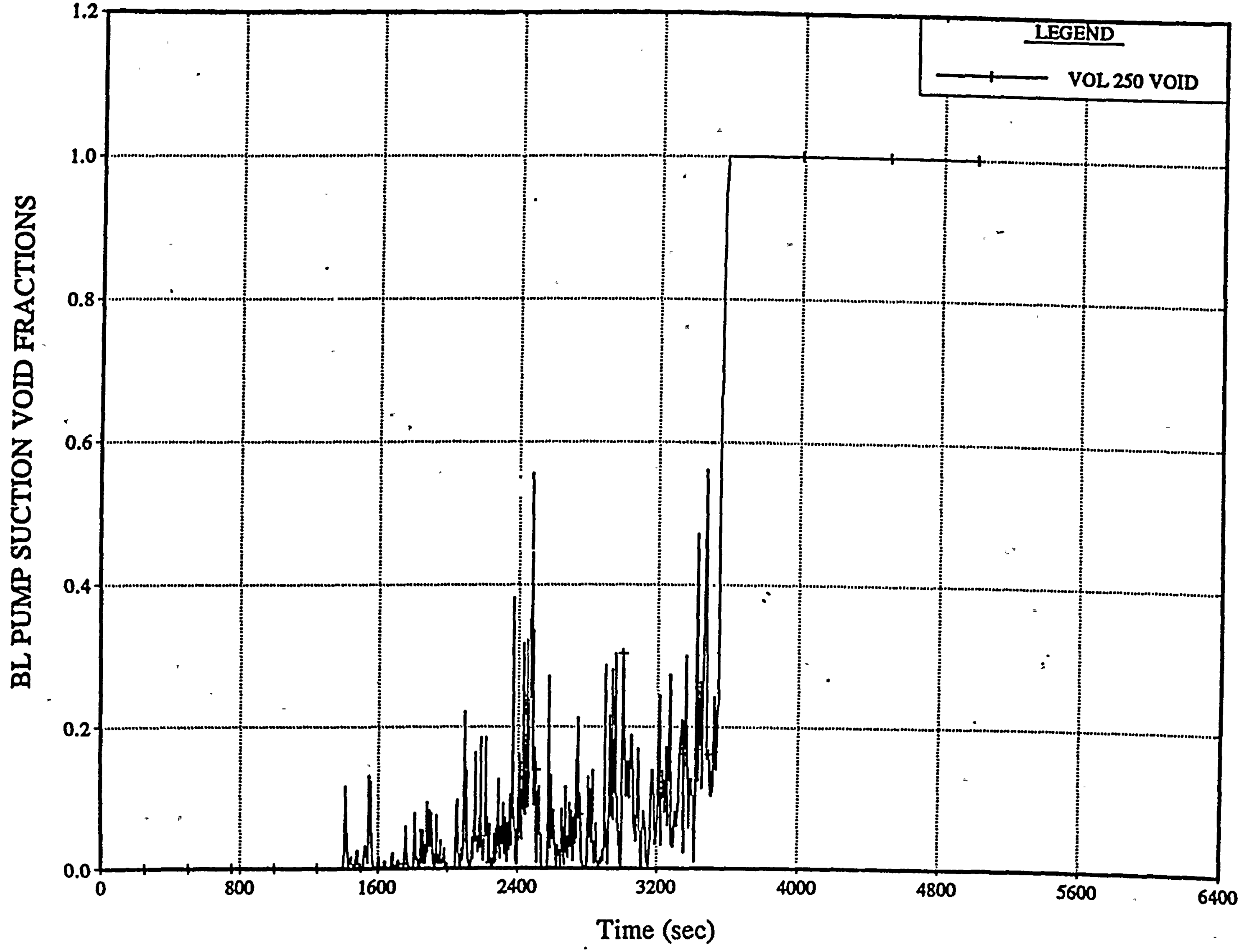
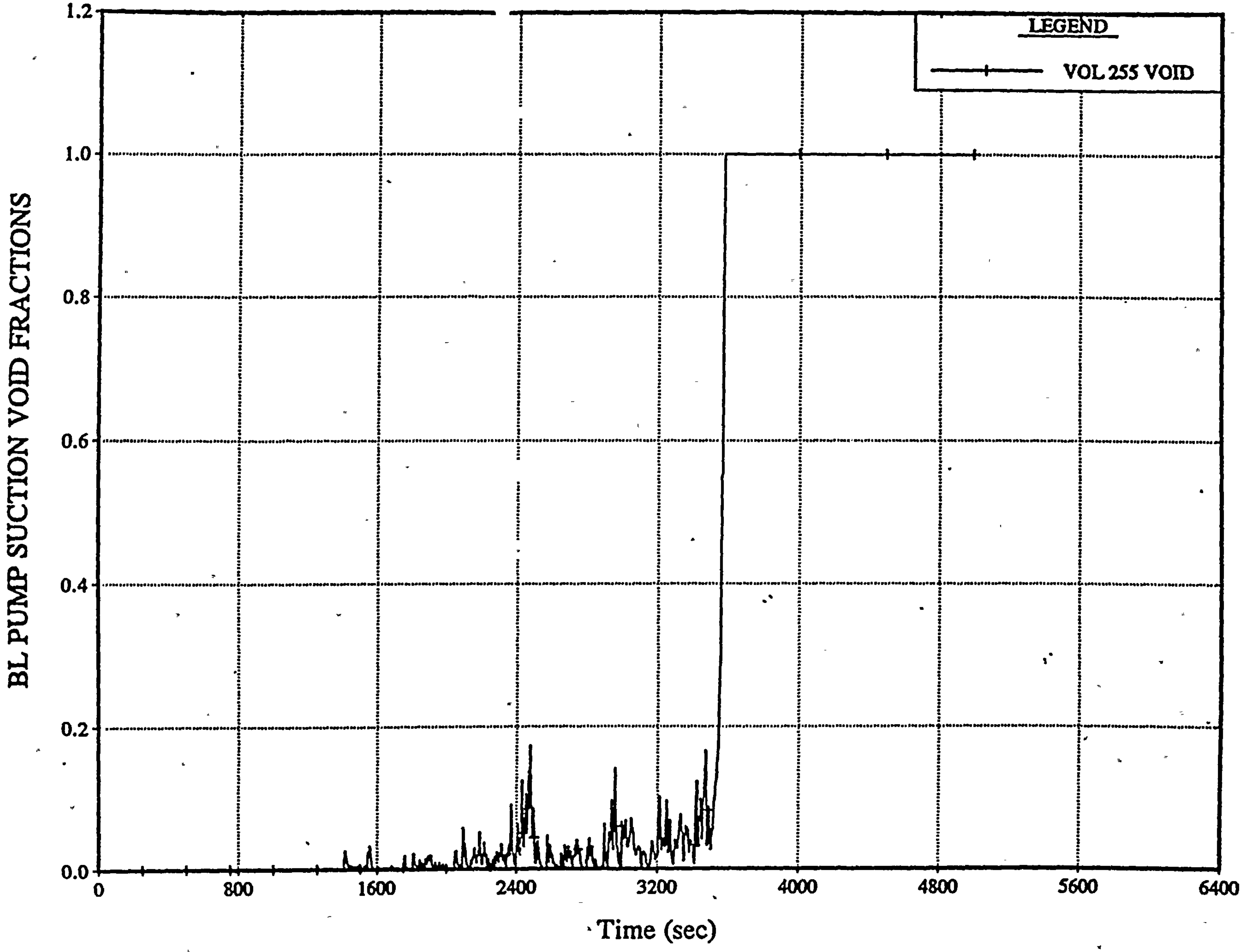


Fig 16

20

Fig. 1-16

R5/2 2.1 INCH PD BREAK Split BL Pump Vol 260
RELAP5/MOD2 Ver 20.0HP



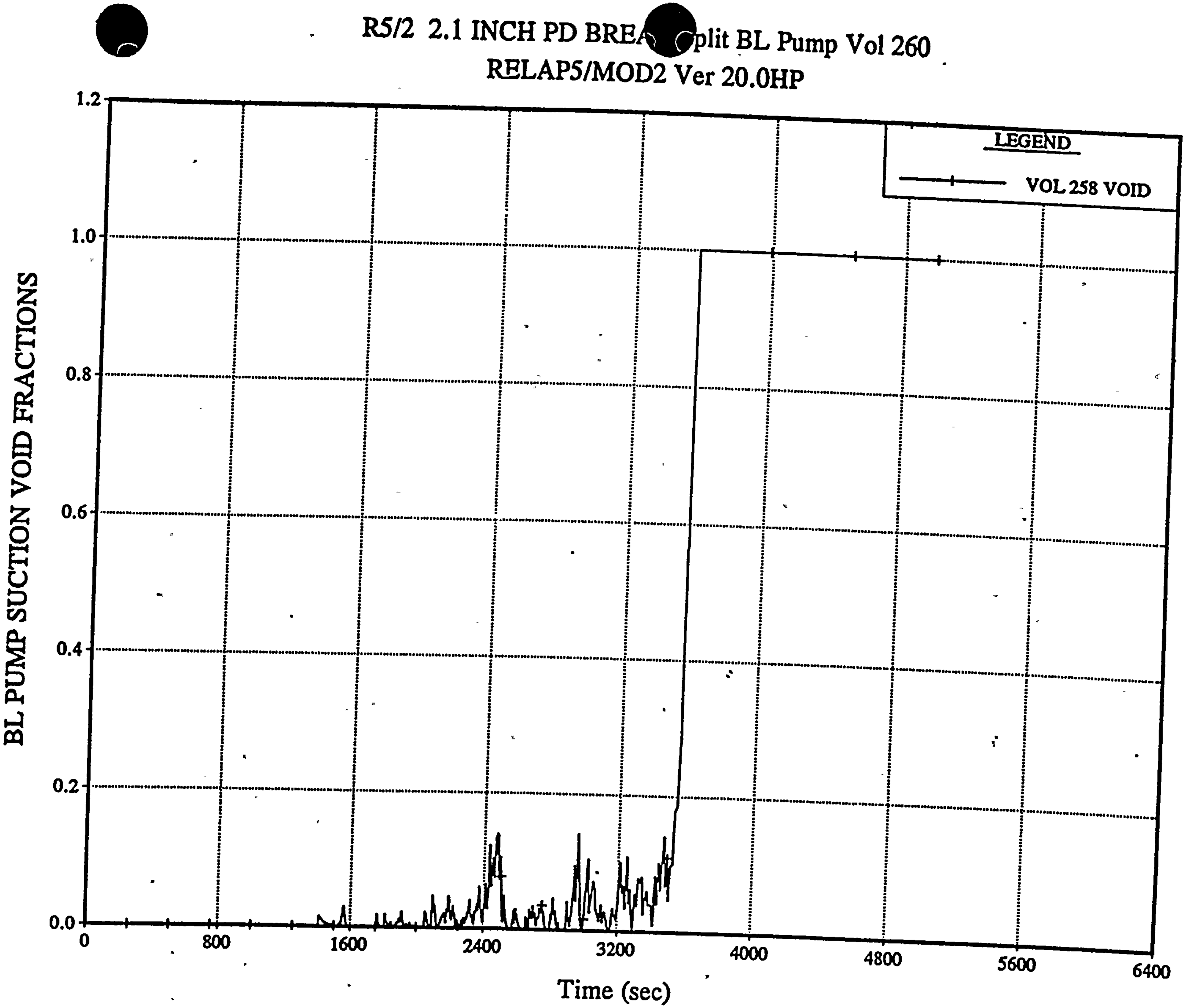
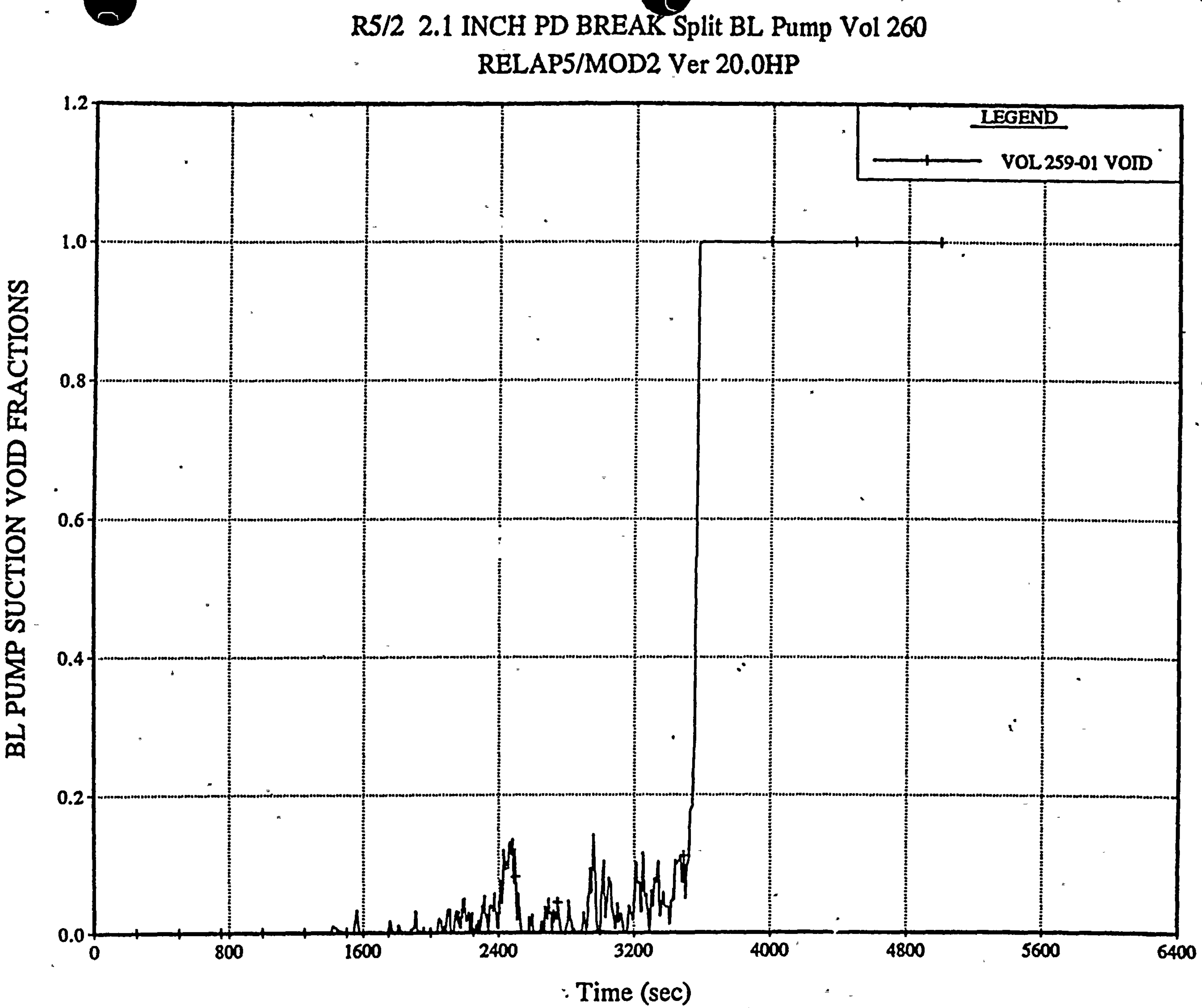


Fig 18

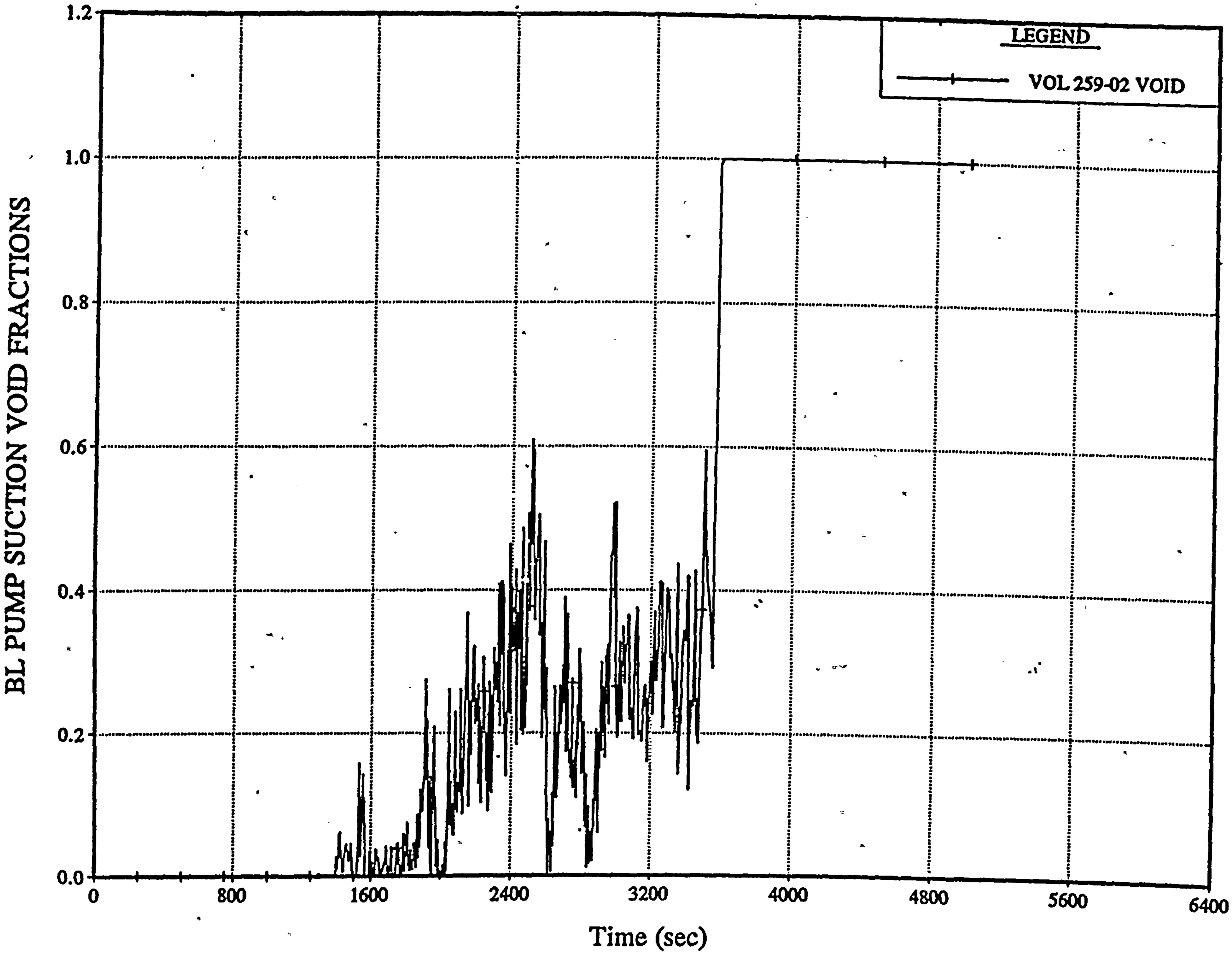
Fig 18

22

TATR VWRO VOIDS...


R5/2 2.1 INCH PD BREAK Split BL Pump Vol 260
RELAP5/MOD2 Ver 20.0HP
LEGEND
VOL 259-01 VOID
BL PUMP SUCTION VOID FRACTIONS
Time (sec)
0.0
0.2
0.4
0.6
0.8
1.0
1.2
0
800
1600
2400
3200
4000
4800
5600
6400

R5/2 2.1 INCH PD BREAK Split BL Pump Vol 260
RELAP5/MOD2 Ver 20.0HP



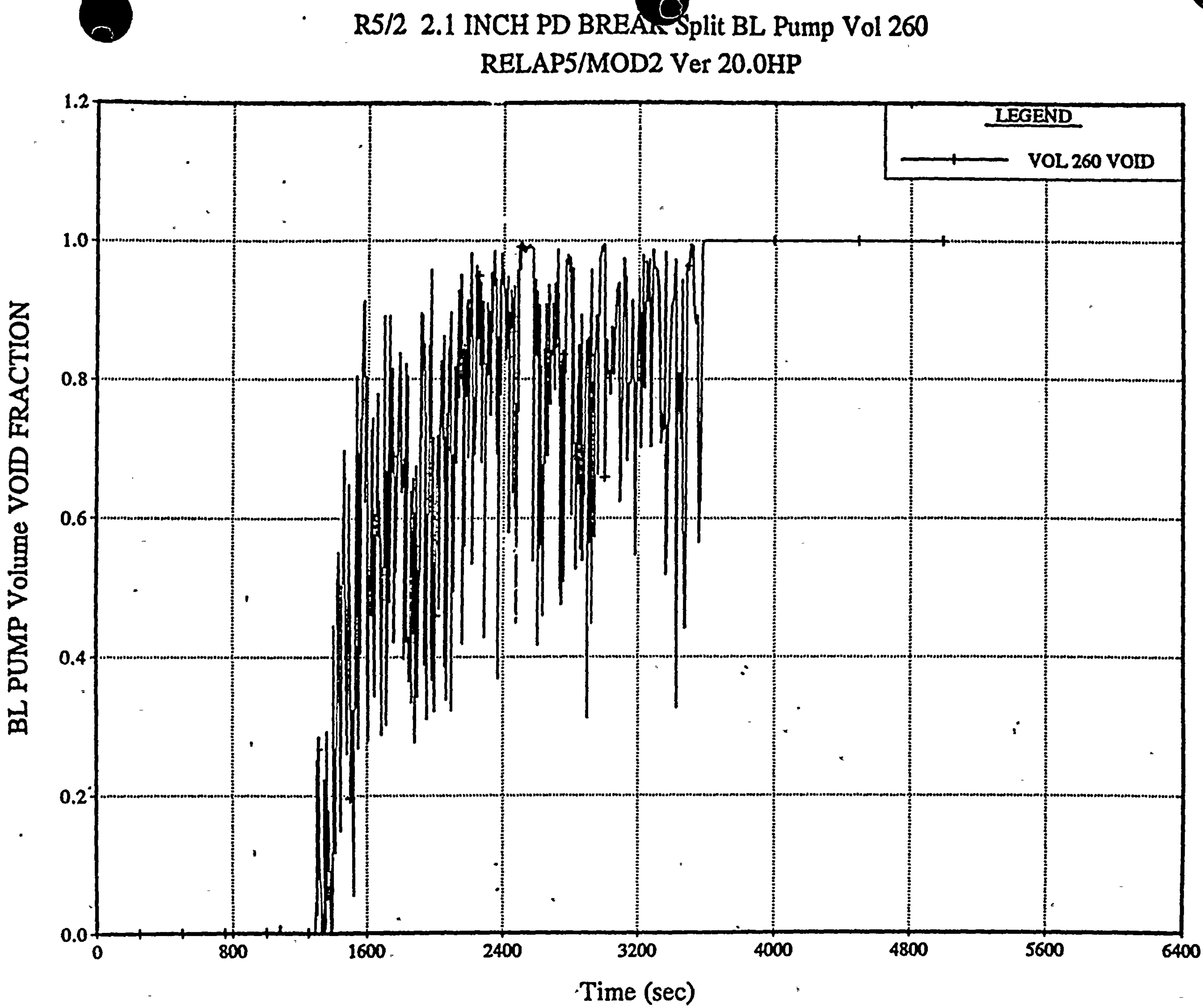

R5/2 2.1 INCH PD BREAK Split BL Pump Vol 260
RELAP5/MOD2 Ver 20.0HP
LEGEND
VOL 260 VOID
BL PUMP Volume VOID FRACTION
Time (sec)
0.0
0.2
0.4
0.6
0.8
1.0
1.2
0
800
1600
2400
3200
4000
4800
5600
6400

Fig. 21

R5/2 2.1 INCH PD BREA[hole]plit BL Pump Vol 260
RELAP5/MOD2 Ver 20.0HP

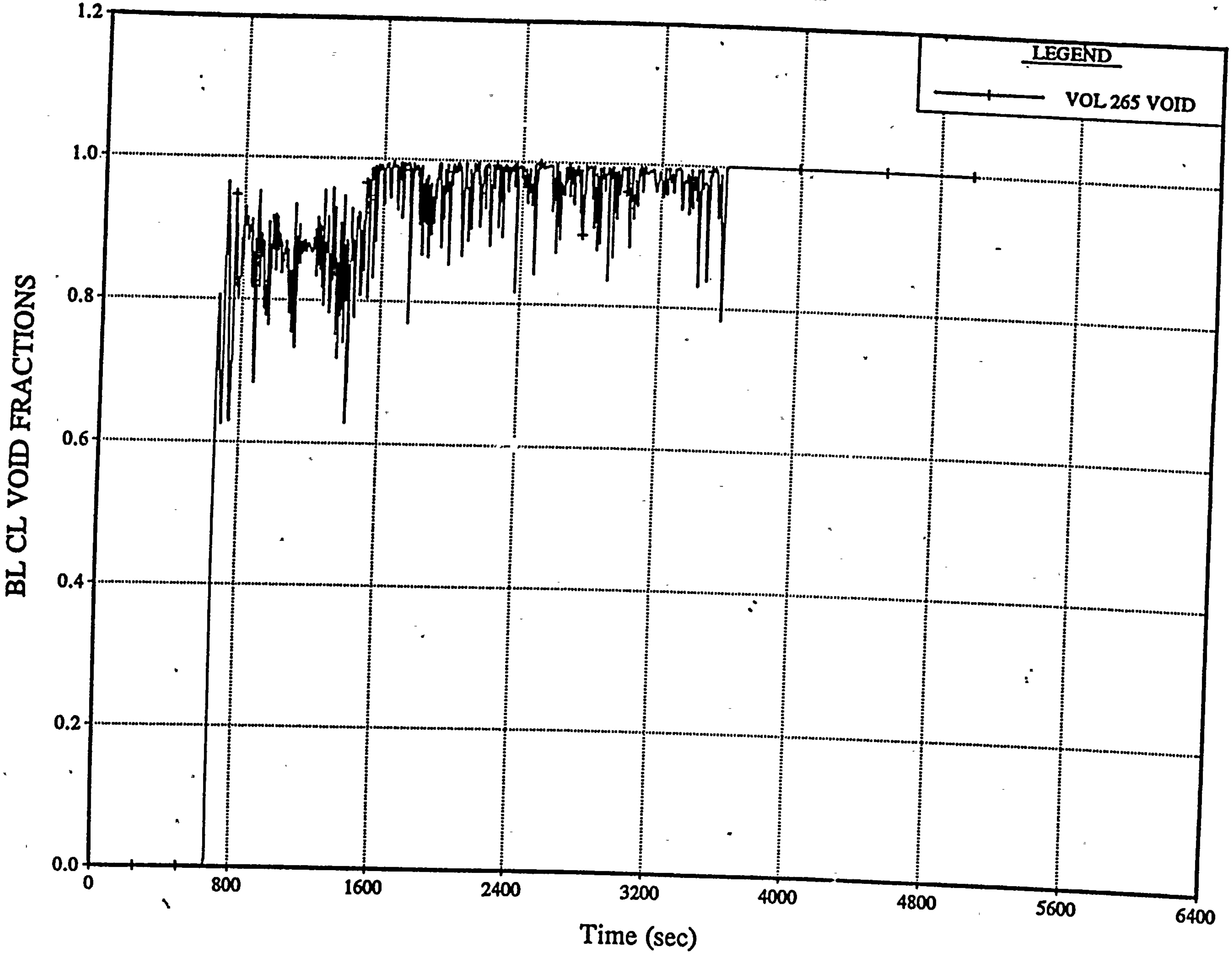


Fig 22

Break Orientation: The break orientation, for SBLOCA studies, is placed at the bottom of the cold leg piping, between the ECCS injection location and the reactor vessel, since this configuration poses the greatest challenge to the ECCS in providing sufficient coolant flow to maintain core cooling. With the break so situated, ECCS entering the RCS through the injection nozzle in the broken cold leg must pass over the break prior to penetrating the reactor vessel. Unless the pump discharge piping is already full, the emergency coolant will be passed out of the break, unable to provide core cooling. This limits the effective ECCS flow, during critical cooling times, to that injected into the remaining loops (intact loops). For that reason, most plants have limits on the amount of injection that can be delivered to any one loop or leg during SBLOCA. A typical limit is that no more than 70 percent of the total ECCS flow can be delivered to any one injection nozzle.

The issues involved with the evolution of SBLOCA transients having alternate break orientations are primarily concerned with the longer term management of the accident than with the measurement of the capability of the ECCS system to provide sufficient and timely injection. The investigation of an SBLOCA scenario with the break at the top of the pump discharge piping is illustrative. For the first period of the transient--reactor trip, ECCS initiation, and loop draining through loop seal clearing--the LOCA is essentially the same irrespective of the break orientation, top, side, or bottom. The pump discharge piping is essentially full of water. Plant pressure is controlled by a balance between the volumetric discharge through the break, the vapor generation in the core, and condensation in the steam generator, if that is needed. Plant inventory is being lost rapidly and a liquid level imbalance is being setup between the downcomer and the core in order to achieve loop seal clearing. Loop seal clearing, when it occurs, is self advancing and rapid. At the end of loop seal clearing, one or more loops have been cleared of liquid; the liquid is retained in the core and downcomer. The downcomer core level imbalance is reduced to that necessary to drive steam to the break. This process, though dependent on break size, is independent of break orientation; it occurs in essentially the way same for bottom, top, and side breaks. Some arguments exist that side and top breaks offer less potential for liquid diversion to the break during loop seal clearing and, thus, arrive at a stable cleared configuration with higher vessel inventories than do bottom breaks. That effect, however, is difficult to demonstrate.

Following loop seal clearing, the ECCS system is challenged as to its ability to supply water at a rate sufficient to replace the water that is being boiled off in the core. In the critical cases, with a single failure of one of the high pressure injection systems (HPIs) and the break located at the bottom of the discharge piping, the ECCS cannot immediately keep pace with core boiling. The system is then in a boildown mode. The inventory in the reactor vessel continuously decreases until the decay heat drops or the ECCS flow increases (because of system depressurization) to the point of achieving a match with the core boiling. If the imbalance is sufficient, the core may uncover, exposing its upper regions to steam cooling before the match occurs. Modeling this phase of the transient with a bottom break is limiting because top or side breaks have effective ECC flows, that are up to 40 percent higher. Thus, for the initial system response and the determination of the adequacy of the ECCS, the bottom break is clearly the conservative choice.

After this initial period, some differences in the modes of accident recovery do occur. Following the acceptable match of decay heat and ECCS flow, the decay heating will continue to decrease at a slow rate; the system pressure may also continue to slowly decrease. This will create excess ECCS and the reactor vessel will start to refill. The rate is dependent on the particulars of the accident and can vary from a reasonable refill rate to an extremely slow one. Eventually the downcomer will be refilled with ECCS water backing up into the discharge piping. At this point, the behavior of the bottom, and side and top breaks starts to differ. For bottom breaks, the liquid backing up into the discharge piping will result in a fluid quality change at the break such that the break discharge is sufficient to remove excess injection. The downcomer remains full; the core, being hydrostatically balanced against the downcomer, is well covered and nothing of significance occurs for an extended period of time. For a side or top break, the break flow cannot respond to the rising system water level and the excess ECCS eventually spills over into the pump suction piping. Whether the loop seals reform or not and the consequences of that happening depend on many factors including operator action to manage the accident.

That the plant is safe and can be managed acceptably during recovery is, in FTI's view, a concern for the plant Emergency Operating Procedures (EOPs) or other devices that control the eventual recovery of the plant. The initial response of the ECCS, its adequate sizing, and the establishment of long-term cooling have, by this phase of the accident, been established. That is the purpose of 10CFR50.46. The eventual recovery from the accident, the evaluation of the multiplicity of operator actions, and their affect on the RCS and core are operational matters. Furthermore, these evaluations should be conducted with realistic boundary conditions such that expected and probable plant behavior is described; aberrant, supposedly conservative assumptions, should not be used. Still an investigation into the possibilities can be useful in determining if any role remains for LOCA analysis past the initial ECCS response.

There are four main factors that determine the continued course of an SBLOCA for side and top breaks. Actually, even a bottom break will eventually evolve to the same configuration as side and top breaks since the break flow cannot be adjusted infinitely, but their development requires an extremely long time period. For our purposes, it is sufficient to consider just the top or side break. The main factors are:

a. The amount of steam flow possible through the upper head spray nozzles (UHSNs).

   This vent path, if it supports the core steaming rate, can eliminate the need for steam venting through the loops. Because core steaming is dependant on decay heat, the UHSNs increase in significance as time progresses.

b. The amount of steam or water that can be passed through the reactor vessel fit up leakage.

   Hot side to cold side leakage is another vent path capable of eliminating or reducing the need for loop venting. This mechanism responds with time in two ways. First, decay heat decreases with time reducing the amount of steam to be vented and, secondly, the RCS nominal temperature also decreases with time, increasing the fitting gaps and improving vent capability. Care should be exercised in applying leakage credit during partial core

uncovery since the steam in the upper head will be superheated, tending to heat the metal structures and reduce the gaps.

c. Whether the mechanism for filling the suction lines evolves gradually or it is a spontaneous development.

If the means for spilling water into the suction piping is the decrease in decay heat, the build up of excess injection will occur slowly and the accumulation of water in the suction piping will be gradual. The potential for blockage will be imposed gradually and at times beyond which loop venting may not be needed. If, however, the increase in spillage is rapid, as may occur because of the return to service of a failed injection system, the potential for blockage can occur with reasonable rapidity.

d. The amount of steam flowing through the loops that is not condensed in the steam generators.

This of course is the most direct factor of concern in evaluating the effect of re-closure of the loop seals. An important consideration is the degree of management credited. If the steam generator pressure control is conducted as intended by the EOPs, the plant will evolve to a reflux mode with no need for loop venting except where spontaneous increases in injection flow occur (item c).

Depending on the plant, the UHSNs can eliminate any concern over a secondary loop seal clearing process. All Westinghouse plants, classified as T_{cold} upper head plants, have reasonably large UHSNs. McGuire/Catawba and Sequoyah are examples of such plants. An examination of the Sequoyah calculations for a 1.9-inch break shows that the process of loop seal clearing is interrupted at about 2,000 seconds by the development of a head imbalance between the downcomer and the core that is large enough to support sufficient steam flow through the UHSNs to eliminate the need for loop venting. For this break and breaks of smaller cross-sectional areas, the loops never clear and, after achieving a minimum suction piping downside level, the suction piping will gradually refill. Because the core swell factor (mixture level divided by the collapsed level) is approximately proportional to core steam generation and the differential pressure required for flow through the UHSNs is proportional to the square of the rate of steam generation, the elevation head difference between the core and the downcomer will decrease more rapidly than the swell height difference as decay heat drops. The core mixture level actually increases with time, assuring continued core cooling. Therefore, for breaks that do not require loop seal clearing during the initial system response, no need for clearing will develop later in the accident. Further, for larger breaks that do require loop seal clearing, the ability to flow sufficient steam through the UHSNs will develop with time, also eliminating the need for loop steam venting. Thus. for T_{cold} upper head plants, because the UHSNs have substantial capability for steam venting, no concern over the refilling of the loop seals with time exists.

For T_{hot} upper head plants, the UHSNs are not sufficient to vent a meaningful amount of steam. Such plants can be bounded by considering the results of excess ECCS for a theoretical plant, absent UHSNs and internals leakage. To this end, an evaluation has been conducted for a plant without UHSNs or internals leakage and for which no operator actions have been taken to manage the accident. The analysis comprises an examination of the potential condition of the RCS following a 2-inch diameter break in the side or top of the cold leg just after loop seal clearing, 1½ hours into the accident, and at six hours into the accident. In each case, sufficient time has elapsed for the suction piping to have been refilled to the extent predicted. The plant is considered to be in a transient mode for the evaluation of the conditions post-loop seal clearing and in a quasi-steady-state for the evaluations at 1½ and six hours. The spectrum of conditions considered are one and four loops venting and one or two HPIs providing makeup. No injection is arbitrarily lost or spilled from the system. The timing of loop seal clearing was obtained from available spectrum calculations performed with the evaluation model. The timing may differ slightly for a top break with two HPIs, but that is not a significant simplification.

One key in understanding the analysis is to realize that a transport mechanism for the core energy must exist. Either the core is boiling and steam is being used to transport energy to the break or the RCS is basically water solid and experiencing natural circulation. A water solid configuration at six hours is possible, if the operator has followed the EOPs and depressurized the steam generators. However, there is no concern for loop seal blockage in a circulating system so that case will not be considered further. Because steam is the transport mechanism, the core is boiling and the flow rate of water to the core can be determined by balancing the heads between the suction riser section and the core given that the inlet enthalpy is specified. For this evaluation, the core inlet enthalpy was assumed to be the injection enthalpy and a level credit was taken for the difference in the downcomer liquid density and the core average liquid density. An analogous assumption, that the core inlet is saturated, can be made with no density difference applied between the core and the downcomer. Either approach achieves essentially the same core mixture level. One depresses the core collapsed level less, while the other generates a higher mixture swell. Steam generated in the core passes through one or four loops and is mixed with liquid in the pump suction riser section at the spill under. Here, excess ECCS subcooling condenses steam to the extent possible and any remaining non-condensed steam is bubbled up through the riser section to the break. For the post-loop seal clearing analysis, the pressure is taken from the reference RELAP5 calculation. For the extended time evaluations, the pressure is determined from the break model (Moody or Extended Henry-Fauske) and the consideration of mass and energy equilibrium for the RCS. For the single HPI cases, the break requires steam and water to be in equilibrium and only that steam flow (the break steam) was used to lighten (decreased density) the riser section. For the two HPI cases, the HPI sensible heat was sufficient to absorb all of the core heat and no break steam flow occurred. In these cases, the condensation process in the bottom of the riser section was assumed to take place in an exponential pattern over the bottom four feet of the riser section. Forty-eight percent of the steam was condensed in the first one-half foot, eighty percent was condensed by 1½ feet, and all the steam was condensed by four feet.

The table presents the results obtained for liquid collapsed levels in the riser sections of the venting suction piping and the reactor core. The table also indicates whether or not the core is covered by the boiling mixture. As can be seen from the table, the core is essentially covered with a boiling mixture for all cases. The one HPI, four-loop venting case has a core mixture height of 11.9 feet at six hours, which is considered essentially covered. Extending these results to greater times will eventually demonstrate core uncovery. However, operator action in conjunction with the EOPs has been delayed for over 5 hours for these analyses. Because such action will mitigate the consequences of these transients, it is not necessary to consider the response of the system for longer times.

The evaluations provided are appropriate if the processes described and credited are not erratic. That may not be true for the condensation process in the riser sections. At that location, with steam being forced into subcooled water, water cannon or water hammer effects may be produced. In that event, the system can be expected to vary about the nominal conditions derived here. Core mixture levels will be both higher and lower than those indicated, but, because the core heating at these times is not rapid, the core overall should be well cooled. Again, if the operator follows the EOPs, the potential for these conditions will be removed early in the event.

In summary, FTI maintains that the decision to run 10CFR50.46 calculations for breaks at the bottom of the piping is appropriate. These breaks clearly offer the greatest challenge to the emergency core cooling systems. SBLOCA transients may evolve differently for top and side breaks than for bottom breaks, but the evolution is essentially independent of the ECCS. Further, the differences occur during the period of accident management that is the purview of the Emergency Operating Procedures and they should not be evaluated with the required EM conservatisms. Not withstanding these considerations, FTI has considered the evolution of top and side breaks. For T_{cold} upper head plants, the evolution of the transient has been shown to produce a smooth increase of core coolant level with sustained and continuous core coverage after a possible initial uncovery. For T_{hot} upper head plants, inter-vessel leakage around the hot leg nozzles serves the same purpose as UHSNs for the T_{cold} plants, making long-term cooling a smooth process with no core uncovery.

Additionally, top breaks were evaluated out to 6 hours for a plant without UHSNs or inter-vessel leakage. It was shown that, at least on the average, the core will be continuously covered. It was demonstrated that the transient can progress past six hours without experiencing serious core uncovery, requiring many additional hours to produce significant core uncovery. Because the potential to require loop venting in the long term is limited (UHSNs and inter-vessel leakage effects) and because the EOPs typically recommend operations to depressurize the plant early in the transient, thereby refilling the plant and mitigating any need for loop venting, FTI believes that any consideration of times beyond those presented to be the proper subject of operational procedures and not suited for consideration under 10CFR50.46.

Analysis Results for a 2-inch Diameter Pump Discharge Break at the Top of the Pipe

Time hours	Decay Heat %	HPIs Operating	Loops Venting	Pump Suction Riser Collapsed Level feet	Core Collapsed Level feet	Core Mixture Level feet
0.5	2.0	1	1	2.4	14.6	12+
			4	5.5	11.5	12+
		2	1	3.7	13.3	12+
			4	6.2	10.8	12+
1.5	1.5	1	1	4.4	12.6	12+
			4	6.6	10.5	12+
		2	1	7.4	11	12+
			4	8.2	10.2	12+
6.0	1.0	1	1	5.9	11.1	12+
			4	7.3	9.7	11.9
		2	1	7.6	10.4	12+
			4	8.2	9.8	12+

Cross Flow Resistance and Core Modeling: In our 3/28/96 telecon, questions were raised as to the basis for the crossflow modeling used within the core. The modeling is outlined in Section 4.3.2.5 of volume II of the RSG evaluation model report, BAW-10168, Revision 2. Basically, the model is a 20 axial region core, radially divided into a single assembly hot channel and the remainder of the core. Each volume in the core model is connected vertically and horizontally. Vertical resistance is based on core design factors which in turn are based on flow tests for the fuel assemblies. Correlations for the prediction of lateral resistances vary substantially. A k-factor value of 2, based on the interface area between adjacent fuel assemblies, has been selected for the evaluation model. This value produces reasonable results that agree with experimental expectations for SBLOCA. The value, however, does not appear to be unique and either smaller or larger values would also appear to produce valid results. The B&W-designed plant RELAP5 small break evaluation model uses a value of 200 for the base crossflow resistance and does not produce substantially differing predictions. (There are indications, however, that the higher resistance used in the B&W-designed plant SBLOCA model may have a stableizing influence on the calculation.)

Two adjustments are imposed on the basic resistance in order to assure conservative SBLOCA predictions. For the top half of the core, the flow resistance from the average channel to the hot channel is increased by a factor of 10 (flow resistance from the hot channel to the average channel is not increased). This has little effect on the behavior of the core mixture or the core flows below the mixture level. However, above the mixture in the steam cooling region, provided the core has uncovered, the increased resistance limits any tendency to flow steam from the average to the hot channel. It is expected that steam will flow from the hot channel to the average because of the higher vapor generation in the hot channel. Because flow diversion out of the hot channel is a conservatism, that flow is not impeded. However, flow reversion back to the hot channel would have the effect of reducing the hot channel vapor temperature and increasing cooling. Although some flow reversion is expected, the resistance within the model is increased so as to limit the effect. The factor is only applied to the upper half of the core because, on a practical basis, it is not possible to predict acceptable cladding temperatures if the top half of the core is uncovered for an extended period. This modeling adjustment, then, is taken to help assure a conservative evaluation.

For reasons similar to the increased crossflow resistance, the hot channel outlet reverse flow resistance was increased to a k-factor of 200 based on the assembly flow area. It was envisioned that this would reduce the tendency for liquid fall back into the hot channel by encouraging liquid to flow into the average channel and then crossflow to the hot channel. The effectiveness of the high reverse flow resistance, however, is mitigated by the need for the hydraulic solution to achieve a pressure balance between the inlet and outlet plenums. As the flows and void fractions develop axially within the core, the hot channel maintains a slightly increased voiding because of its higher vapor generation rates. This leads to an apparent pressure imbalance between the two columns (hot and average channels) as the core exit is approached. To adjust for this imbalance, the solution allows negative liquid flow into the uppermost volume of the hot channel creating a lower void fraction for that volume. The reduced voiding in the upper volume balances the channel pressures. Note should be taken that the upper two volumes of the hot or average

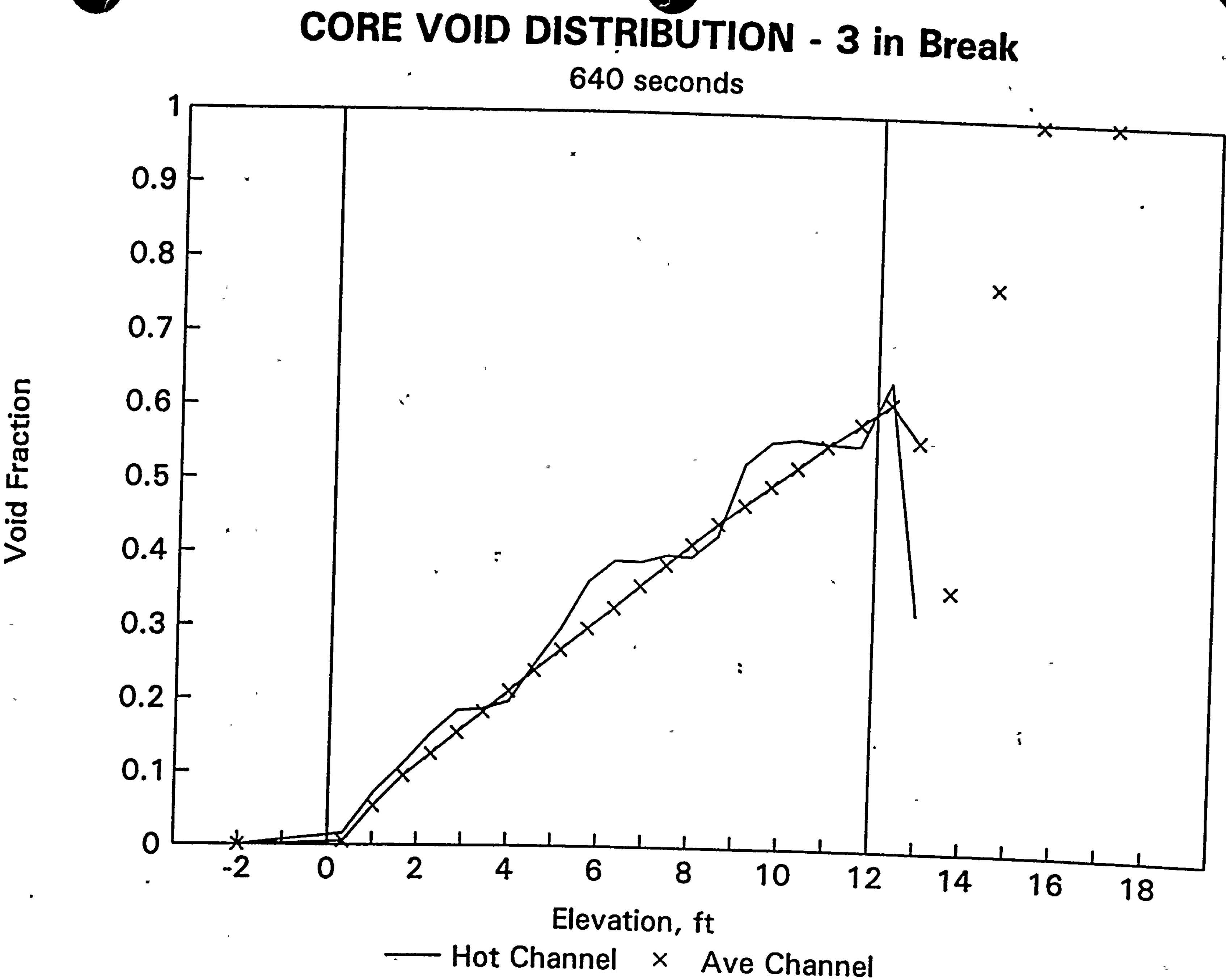
channels do not represent nuclearly heated regions of the plant. These volumes model the upper unpowered segments of the fuel pins (the fuel pin upper plenum and interior springs) and the upper nozzle of the fuel assembly. Thus, the flow and the void reduction do not occur within the core active region. The resultant negative flow from the upper plenum to the hot channel exit volume only occurs when the upper plenum contains some mixture. Model prediction problems are not created because once the inner vessel mixture level falls into the core region the pressure balance is maintained by a slightly increased mixture level in the hot channel. This higher mixture level in the hot channel is physically real and well modeled. Observations of the core mixture level predictions for the hot and average channel discussed below demonstrate the credibility of the solution. The increased resistance has been maintained in the model as a hedge against possible core reverse flow. The resistance does not work as a flow diversion under stagnate conditions but is likely to divert flow away from the hot channel under flow conditions. This would be a meaningful conservatism if SBLOCA were to involve any substantial period of reverse core flow. Although no such period can be identified, the only reverse core flow phases are those occurring during the loop stagnate phases of loop seal clearing and core boildown, the increased resistance factor has been kept as a precaution.

That the hot channel and average channel mixture heights evolve reasonably during a core uncovery can be observed in the attached figures. These figures display the axial void distributions of the hot and average channels as they developed for a 3-inch pump discharge break in a Westinghouse-designed 4-loop plant over the loop seal clearing period. The figures display void fraction versus axial core elevation from the lower plenum to the upper plenum at the elevation of the outlet nozzles. Each void fraction is displayed axially at the center of the volume from which it is taken and is connected to the void fraction of the adjacent nodes by a straight line. If not recognized, this technique can introduce some confusion, as occurs between the lower plenum and the core. The lower plenum is or is nearly liquid solid throughout the time period of these graphs, but the linear connection to the first core volume, which is legitimately voided, produces a visual impression that the lower plenum contains steam as the bottom of the core is approached. In truth there is a step change in void content between the lower plenum and the core. The same recognition should be made in reviewing the upper plenum void fractions. This, in part, is the reason that the channels, except for the lower plenum to the core, are displayed with connecting lines while the upper plenum volumes are displayed as points. The time at which the figure is captured is displayed just above the figure border. Within the upper plenum, the upper most value is at the elevation of the center of the core outlet nozzles. This volume spans the height of the outlet nozzles. The next lower volume is entirely below the span of the hot leg piping.

Loop seal clearing for the case shown in the figures occurs at approximately 715 seconds. The graphs display the core elevation head/mixture height as the necessary head to clear the loop seal develops on the approach to loop seal clearing and as the core refills after clearing. Graphs are provided at 640, 660, 680, 690, 700, 710, 715, 720, and 800 seconds. By 640 seconds, the clearing process has initiated and the core mixture level has fallen below the nozzle belt as indicated by the void fraction in the upper most volumes. (The upper volume represents the portion of the upper plenum adjacent to the outlet nozzles.) The core is still covered with mixture and the depressed void fraction at the exit to the hot channel can be observed. It can also be observed that the correspondence in void content between the average channel and the hot channel is quite good. Deviations occur, but the general trend is a slightly higher void content in the hot channel. There is no indication that the lower void content of the hot channel exit volume has propagated downward. By 660 seconds, more of the upper plenum is voided, but the core is still covered and the core void distributions remain reasonable. At 680 seconds, the columns representing the hot and average channels are starting to void. The upper plenum is essentially 100 percent voided. The core heated regions are still covered since the high voiding has not penetrated below the non-heated regions of the fuel assemblies. By this time, before any core heatup, the void fraction for the hot assembly upper region has evolved into agreement with that of the average channel. At 690 seconds, the heated regions of the hot and average channels have started to uncover. Loop seal clearing is now about 25 seconds away. Because the core outlet void fraction is at 90 percent, the cladding temperatures remain near saturation.

At 700 seconds, the two upper volumes of the heated core are showing substantial voiding and the very top heated node may be experiencing some heatup. For the limited uncovery apparent here, mist entrainment from the mixture may be sufficient to prevent core heatup. The hot and average mixture levels are in agreement as the uncovery proceeds. At 710 seconds, the mixture has fallen to its lowest level during loop seal clearing. The hot and average channel mixture levels remain in agreement with the hot channel slightly more voided. At 715 seconds, the loop seal for the broken loop has cleared and the downcomer and core levels are starting to equilibrate creating a core refill. By 720 seconds, the refill has progressed into the upper plenum. The void fraction at the very outlet of the hot channel is again depressed but that was not observed in the partial refill at 715 seconds. Thus, the predictions of the hot channel exit void fraction are consistent with the needs of the transient prediction, attaining the required degree of accuracy under conditions when core uncovery is occurring or eminent. By 800 seconds, the refill is complete and the core boil down phase has been entered. As shown, the refill did not completely fill the vessel. The region just below the out nozzle remains at an elevated void content and the upper plenum at the outlet nozzle elevation is completely voided.

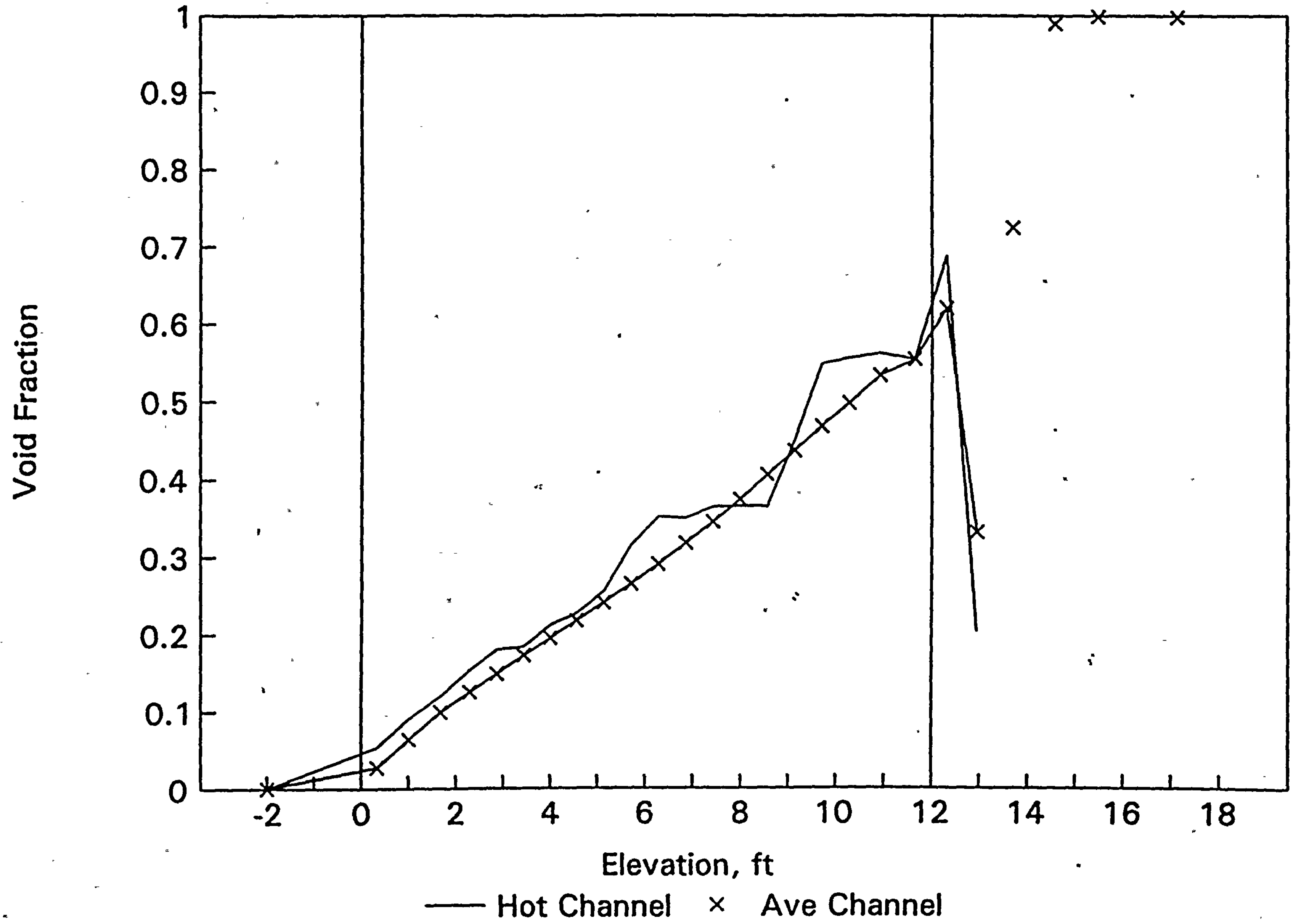
In conclusion, core modeling has been arranged to provide for hot and average channel effects. Specific provisions have been incorporated into the EM to achieve conservative predictions of cladding temperature (crossflow resistance for the upper half of the core). The modeling works well during core uncovery as evidenced by the agreement between the hot and average channel mixture levels. Although a modeling factor does lead to an apparently inconsistent void fraction in an upper unheated volume of the hot channel during those phases of the SBLOCA transient when the upper plenum contains mixture, this difficulty is resolved as the core uncovers and is not present at any time that the calculation is predicting core uncovery or calculating cladding temperature excursions. Therefore, the core modeling approach employed is appropriate for the calculation of small break LOCA simulations.


CORE VOID DISTRIBUTION - 3 in Break
640 seconds
Void Fraction
Elevation, ft
Hot Channel
Ave Channel
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
-2
0
2
4
6
8
10
12
14
16
18

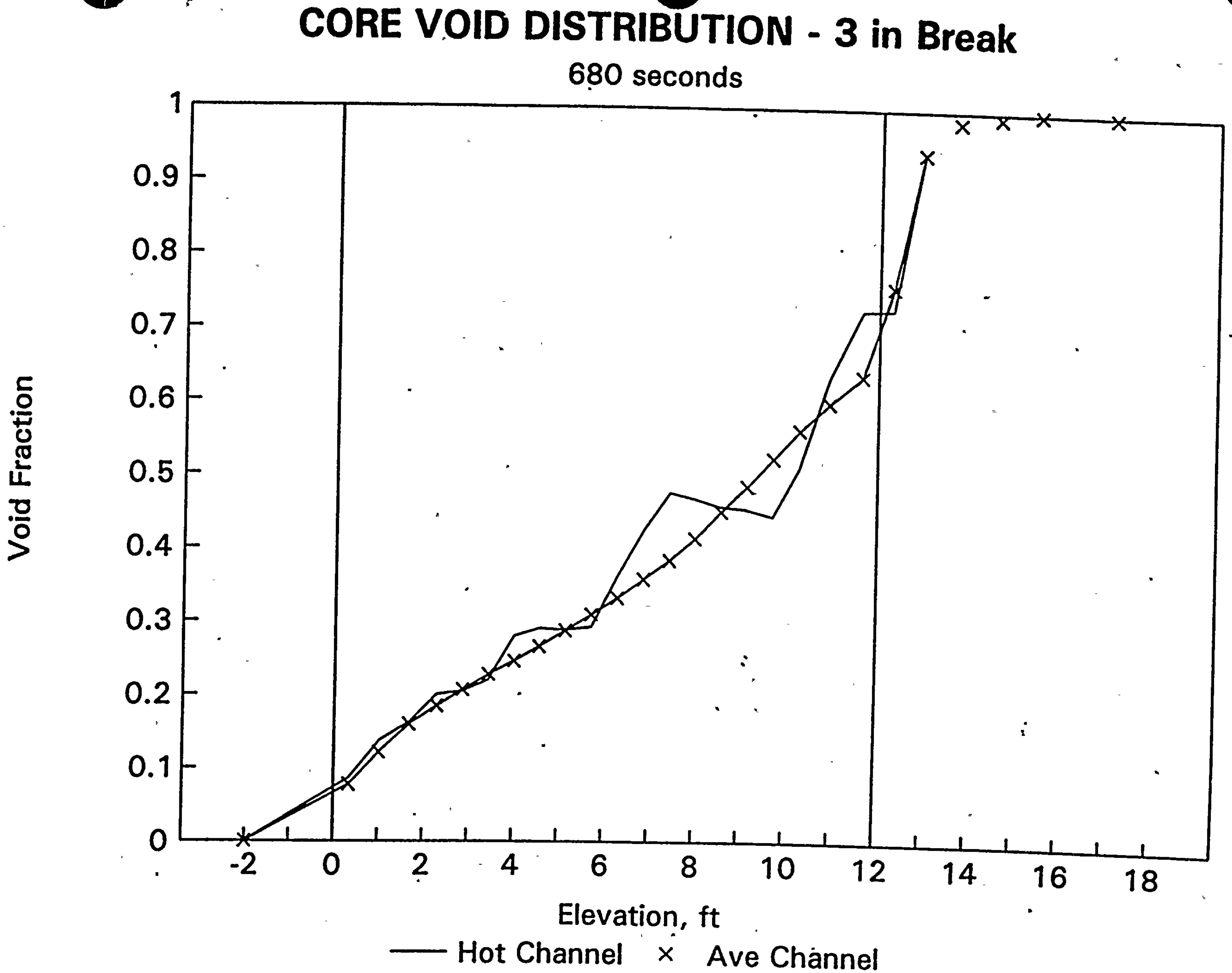
36

CORE VOID DISTRIBUTION - 3 in Break

660 seconds

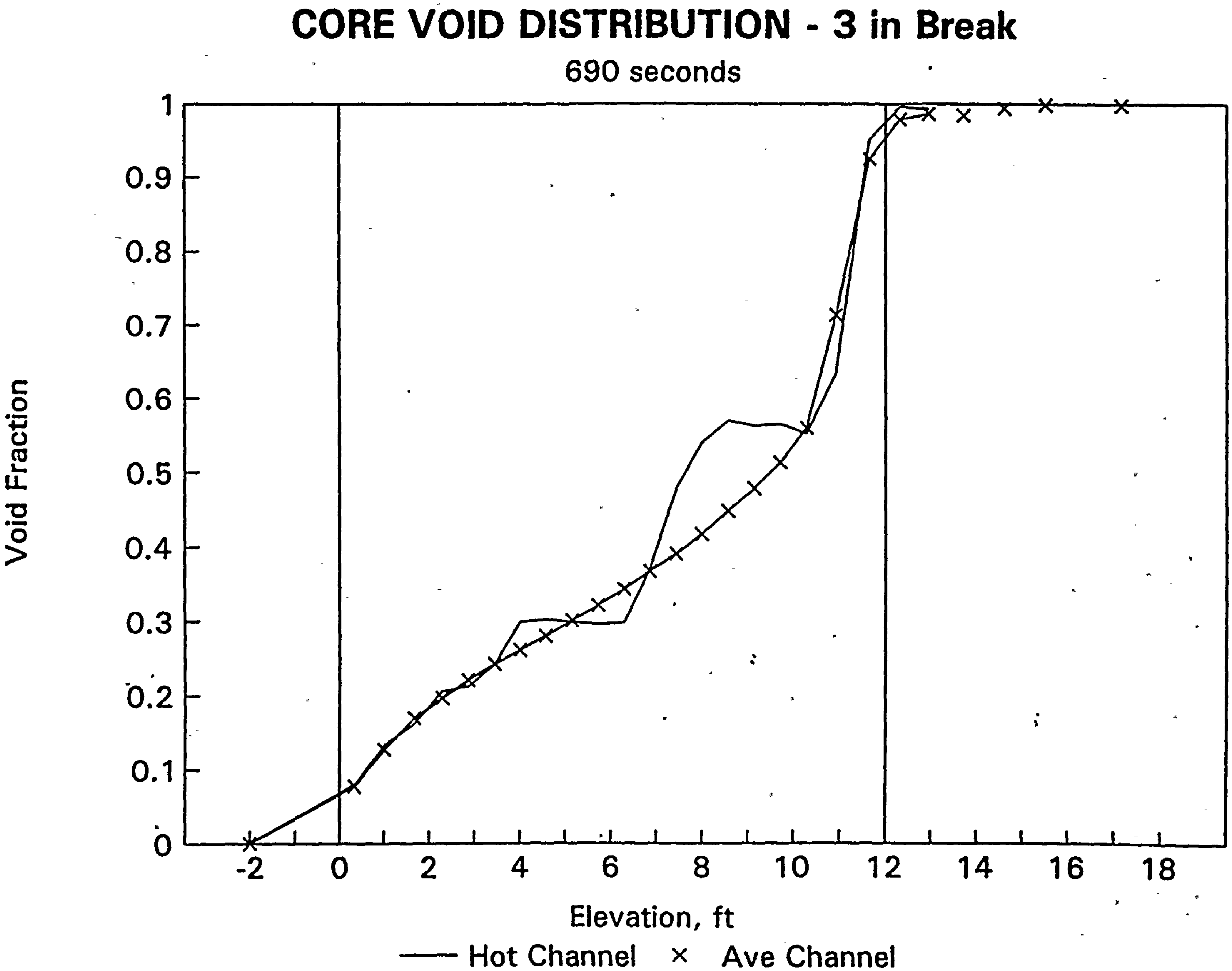


37



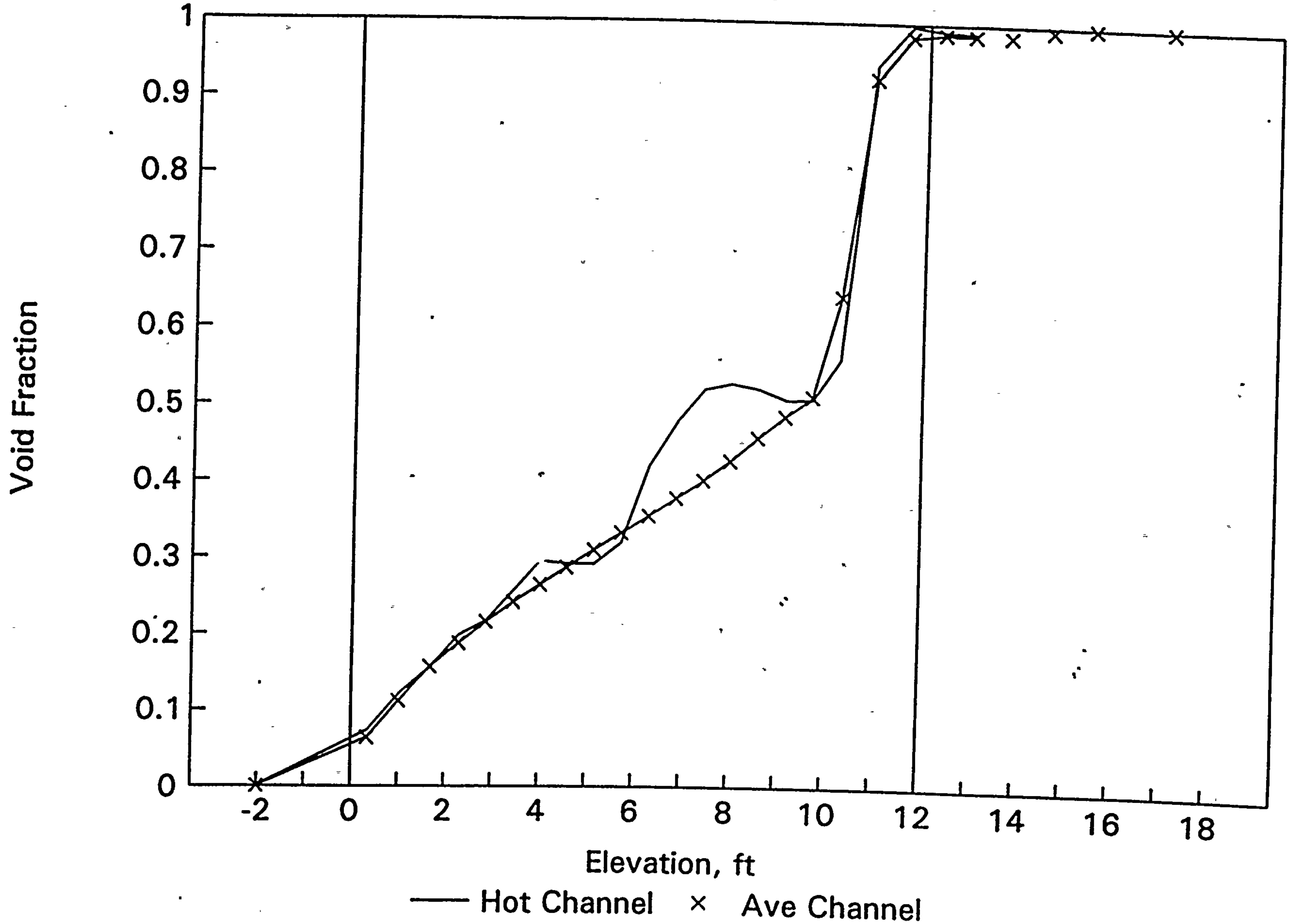
CORE VOID DISTRIBUTION - 3 in Break
680 seconds
Void Fraction
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
-2
0
2
4
6
8
10
12
14
16
18
Elevation, ft
Hot Channel
Ave Channel

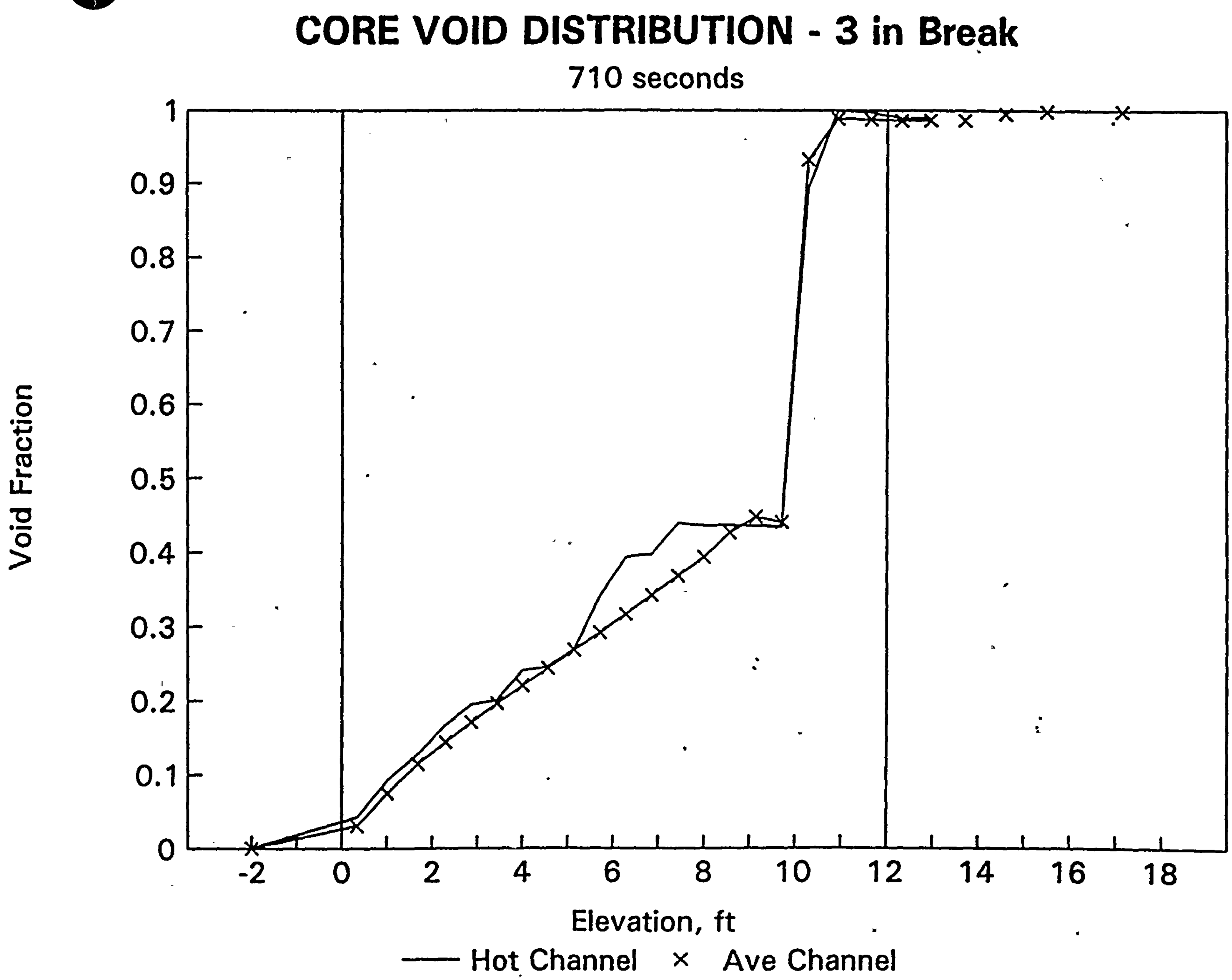
38


CORE VOID DISTRIBUTION - 3 in Break
690 seconds
Void Fraction
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
-2
0
2
4
6
8
10
12
14
16
18
Elevation, ft
Hot Channel
Ave Channel

CORE VOID DISTRIBUTION - 3 in Break

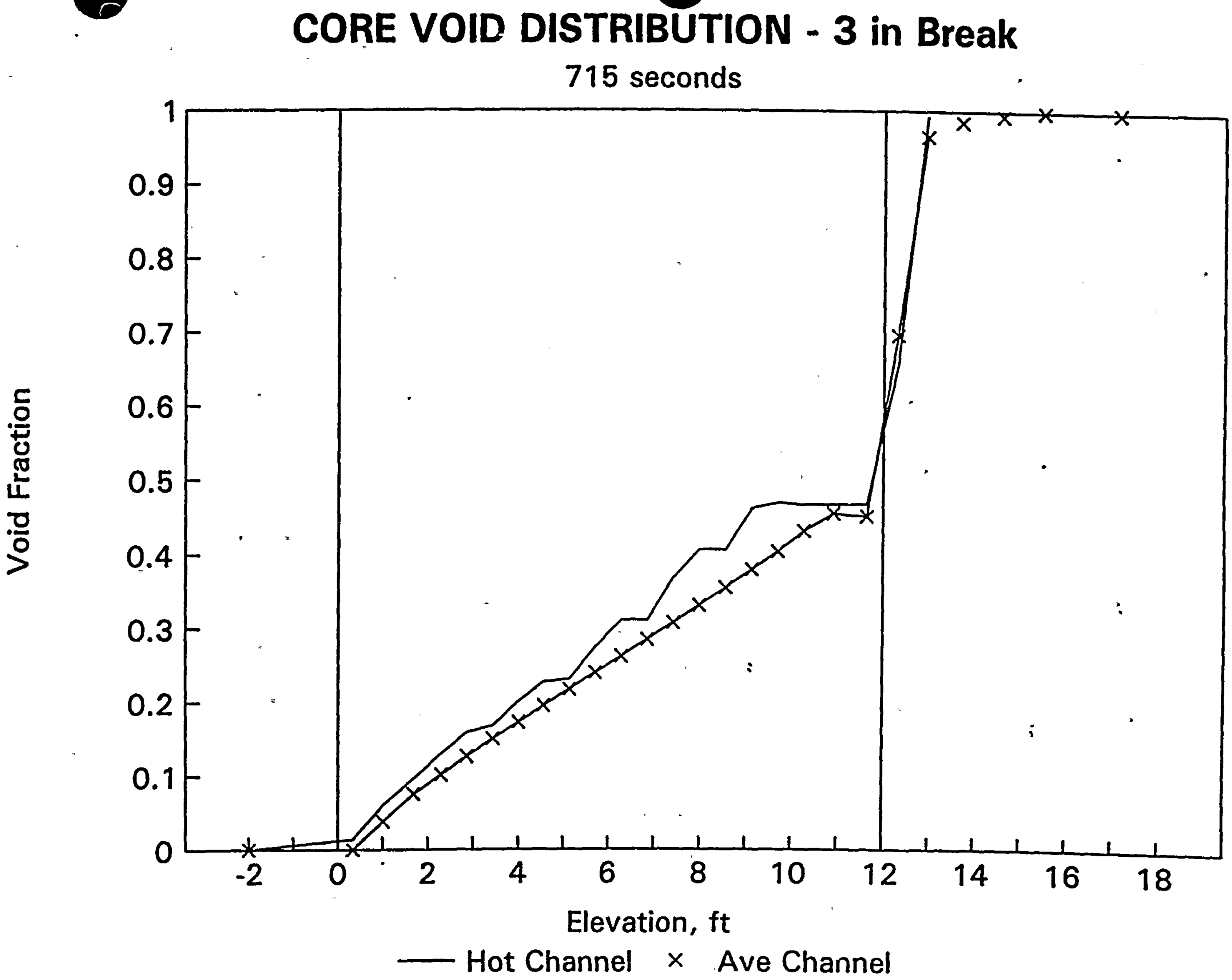
700 seconds





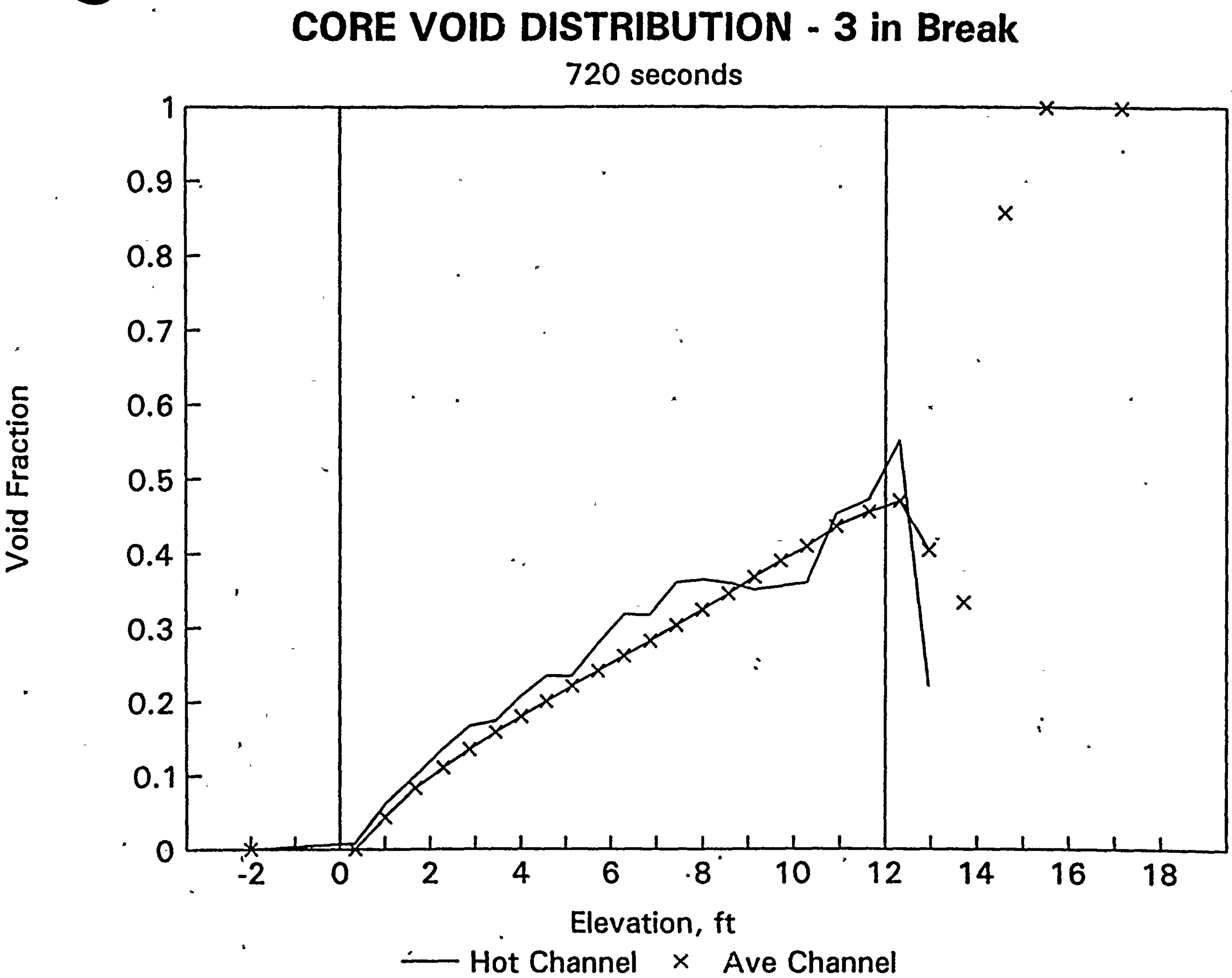
CORE VOID DISTRIBUTION - 3 in Break
710 seconds
Void Fraction
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
-2
0
2
4
6
8
10
12
14
16
18
Elevation, ft
Hot Channel
Ave Channel

41



CORE VOID DISTRIBUTION - 3 in Break
715 seconds
Void Fraction
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
-2
0
2
4
6
8
10
12
14
16
18
Elevation, ft
Hot Channel
Ave Channel

42

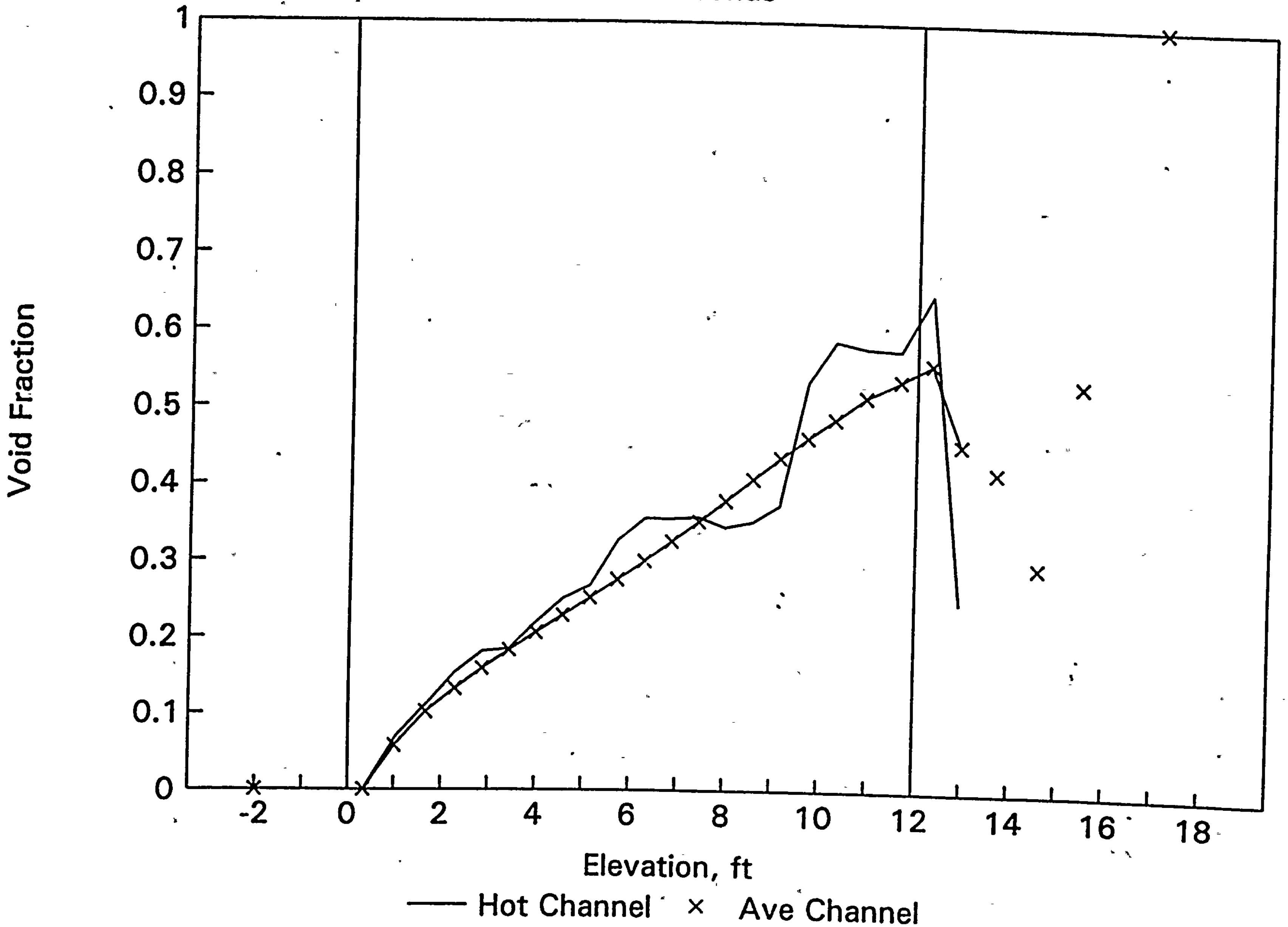


CORE VOID DISTRIBUTION - 3 in Break
720 seconds
Void Fraction
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
-2
0
2
4
6
8
10
12
14
16
18
Elevation, ft
Hot Channel
Ave Channel

43

CORE VOID DISTRIBUTION - 3 in Break

800 seconds



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Supplementary Break Orientation Information:

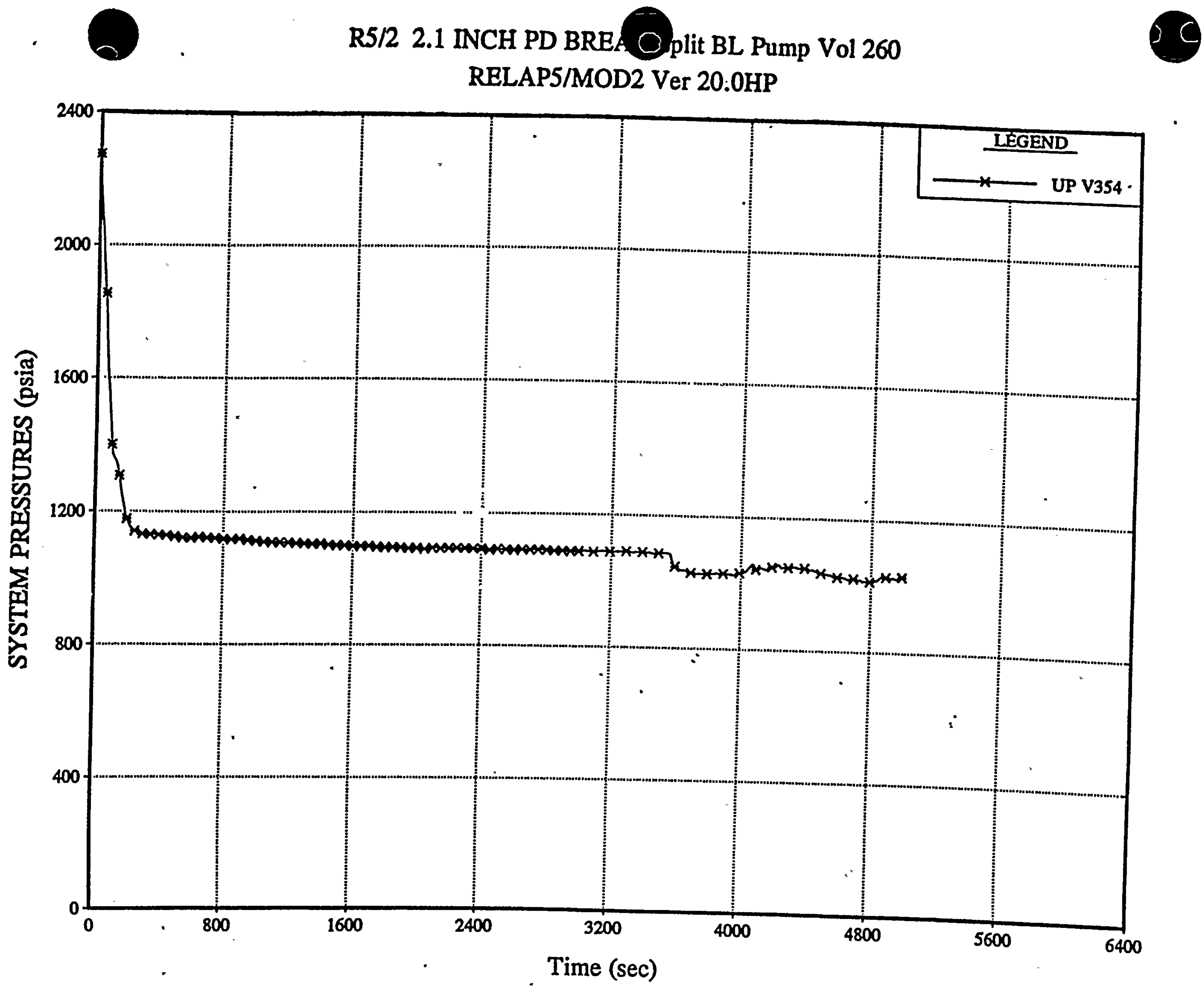
Range of Upper Head Spray Nozzle Areas:

T-hot Plant	=>	≈ 0.02 ft^2	(Trojan, North Anna, Surry, etc.)
T-cold Plant	=>	≈ 0.45 ft^2	(McGuire/Catawba, Sequoia, etc.)

Some plants sit in between these limits with areas of 0.2 or 0.3 ft^2.

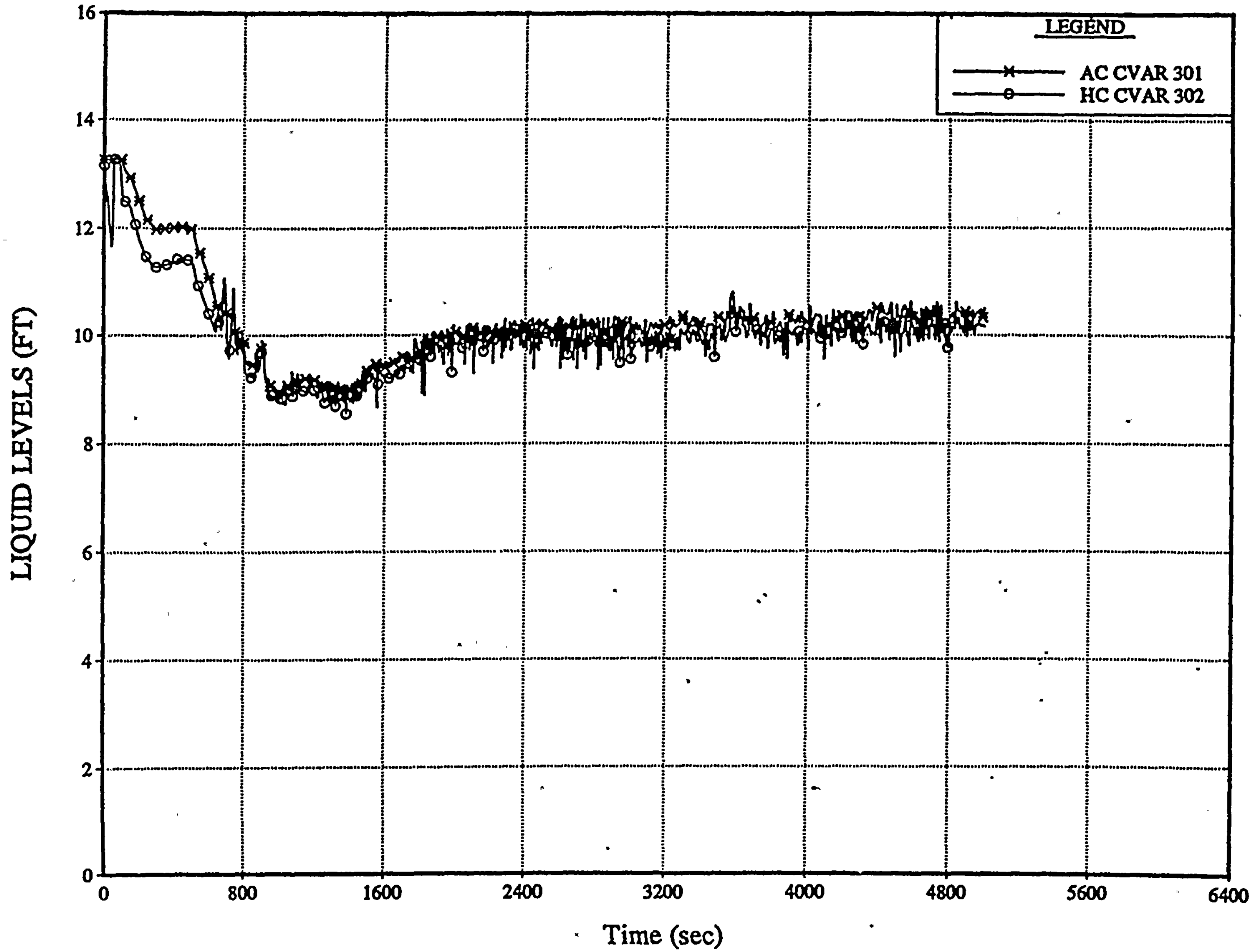
The inclosed plots are for the 2.1 inch case that was provided in an earlier communication. I felt that with them being part of a larger set they would be more useful. If the specific 2 inch case is important we can reconstruct it and send the same plots. Some of the definitions on the plots are:

UP	Upper Plenum
V	Volume or Node
AC	Average Channel
HC	Hot Channel
CVAR	Control Variable For the case of AC CVAR and HC CVAR the display is a collapsed water level for the core region with 0.0 taken at the bottom of the active region. The reason that the values exceed 12 feet is the inclusion to the two unheated volumes of the fuel assemblies that model the fuel pins above the uranium pellets and the upper nozzle of the fuel assembly.
Jun	Junction or Flow Path
J	Junction or Flow Path
UH SPRAY	Upper Head Spray Nozzle
IL ECC	Intact loops ECCS flow
BL ECC	Broken Loop ECCS flow For this case IL ECC CVAR and BL ECC CVAR are simply the high pressure injections. Had the plant depressurized these control variables would have picked up the accumulators and the low head systems.
HOT CH	Hot channel, HOT CH, CVAR is a control variable that approximates the mixture level in the core hot channel. For the purpose of this CVAR mixture is defined as $\alpha < 0.9$. The control variable samples the α from the bottom to the top in each node of the channel. If α is less than 0.9 the height of the volume is considered mixture once α is greater than 0.9 the control volume is considered as above the mixture and the search stopped.


R5/2 2.1 INCH PD BREA split BL Pump Vol 260
RELAP5/MOD2 Ver 20.0HP
LEGEND
UP V354
SYSTEM PRESSURES (psia)
2400
2000
1600
1200
800
400
0
Time (sec)
0
800
1600
2400
3200
4000
4800
5600
6400

46

R5/2 2.1 INCH PD BREAK Split BL Pump Vol 260
RELAP5/MOD2 Ver 20.0HP



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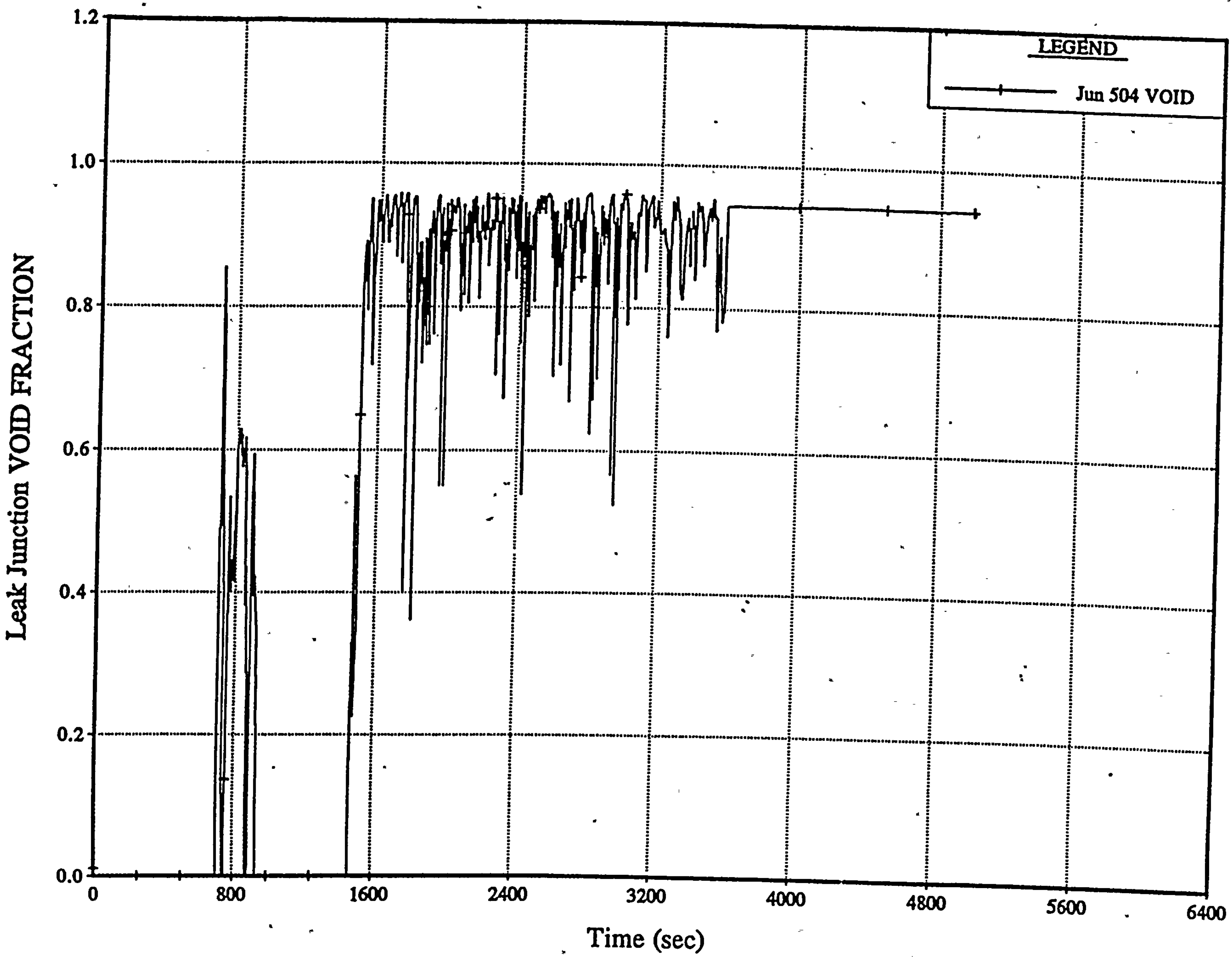
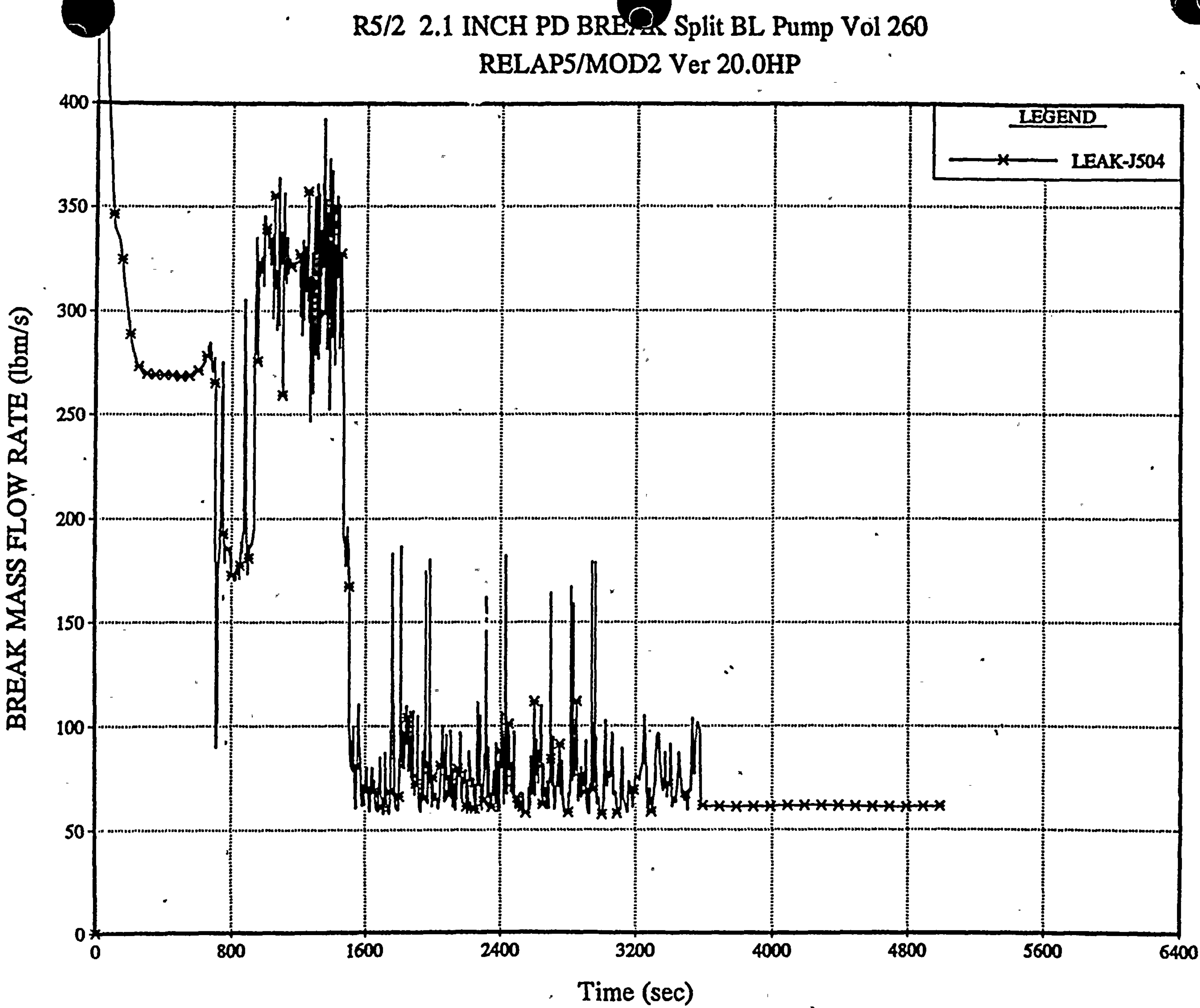
R5/2 2.1 INCH PD BREAK Split BL Pump Vol 260
RELAP5/MOD2 Ver 20.0HP

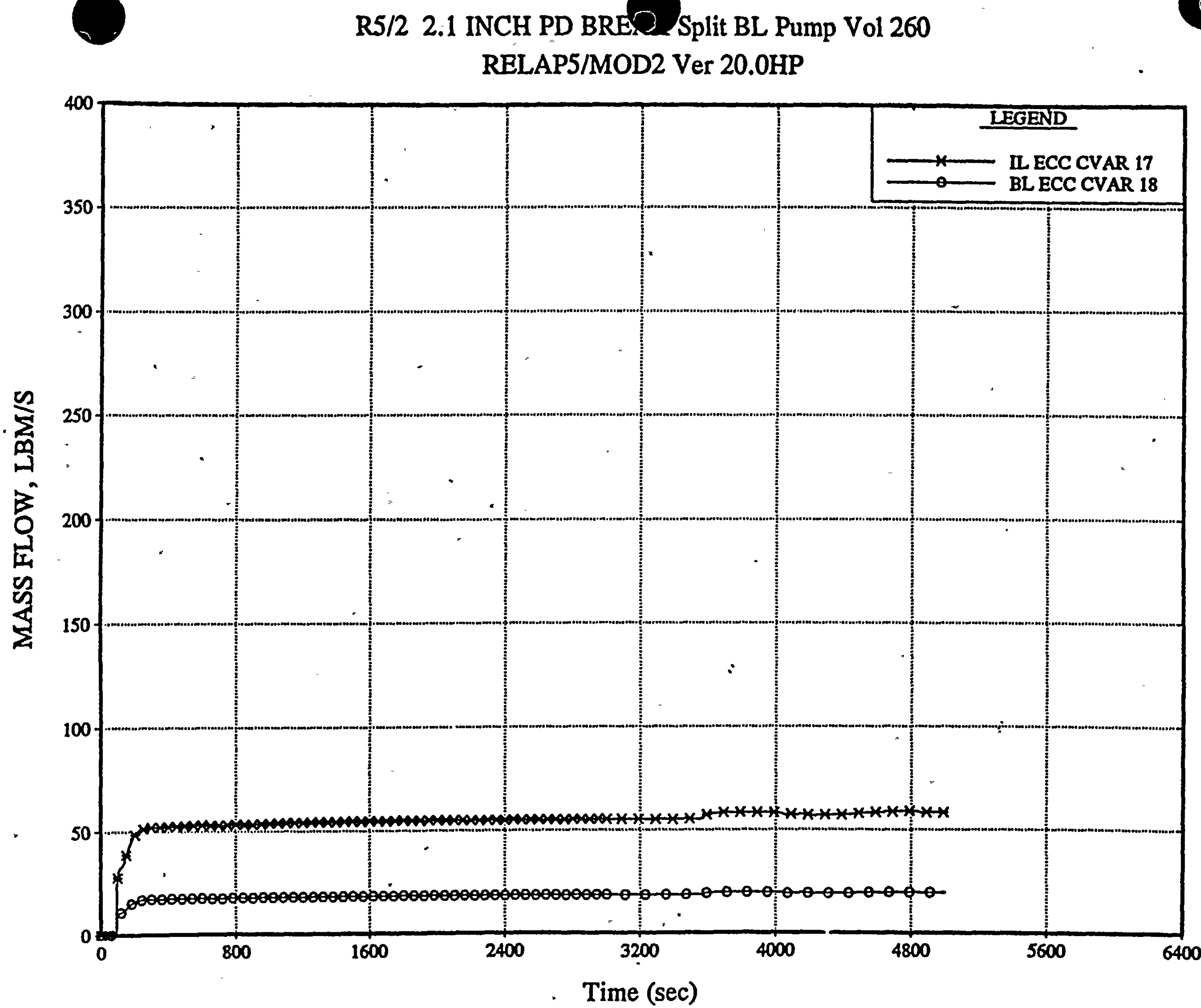


48



R5/2 2.1 INCH PD BREAK Split BL Pump Vol 260
RELAP5/MOD2 Ver 20.0HP
LEGEND
LEAK-J504
BREAK MASS FLOW RATE (lbm/s)
Time (sec)
0
50
100
150
200
250
300
350
400
0
800
1600
2400
3200
4000
4800
5600
6400

49

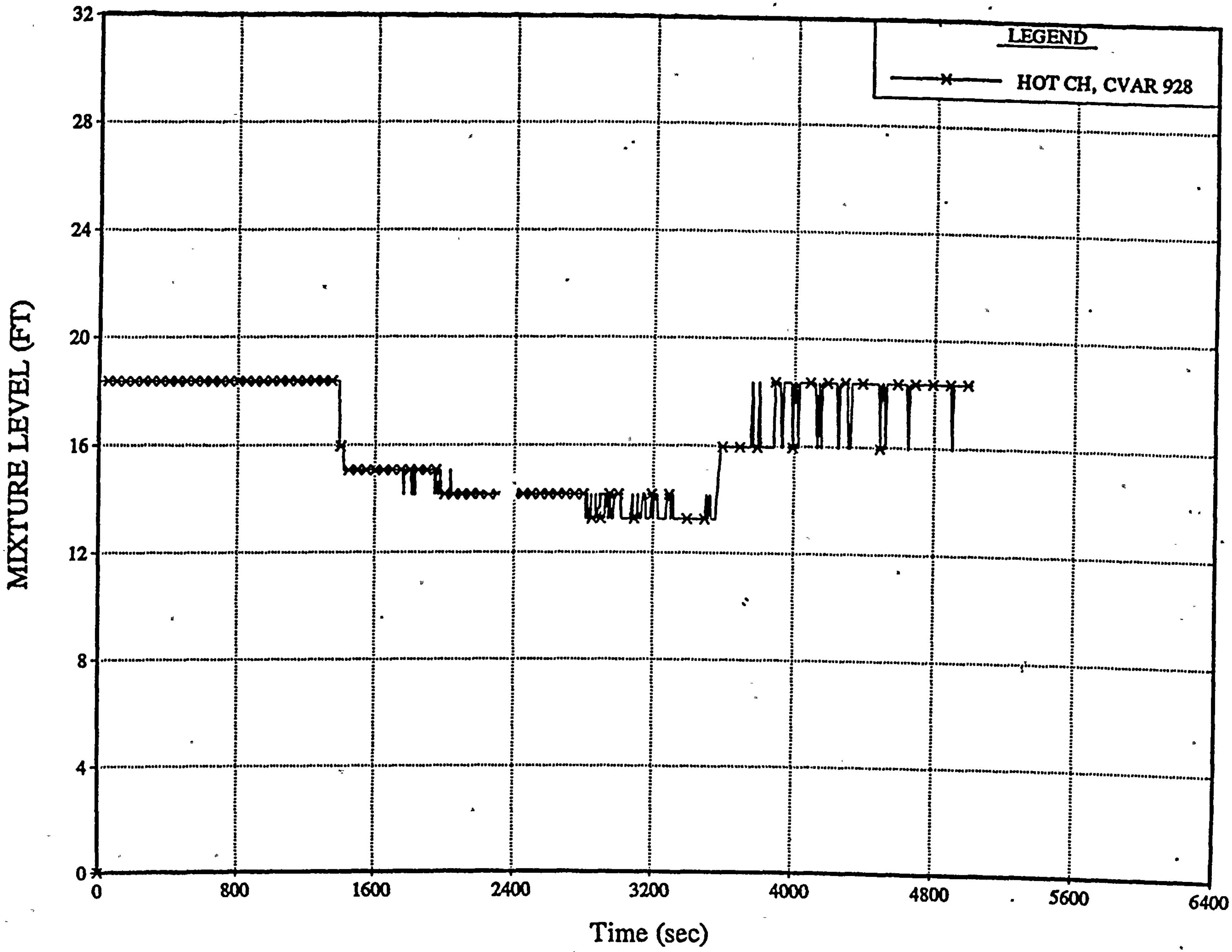


R5/2 2.1 INCH PD BREAK Split BL Pump Vol 260
RELAP5/MOD2 Ver 20.0HP
LEGEND
IL ECC CVAR 17
BL ECC CVAR 18
MASS FLOW, LBM/S
Time (sec)
0
50
100
150
200
250
300
350
400
800
1600
2400
3200
4000
4800
5600
6400

15

R5/2 2.1 INCH PD BREAK Split BL Pump Vol 260

RELAP5/MOD2 Ver 20.0HP



52

SBLOCA Long-Term Cooling: In our 3/28/96 telecon, Bob Jones raised an issue as to the sufficiency of FTI's SBLOCA long-term cooling write-up on page 8-1 of BAW-10168, Revision 2, Volume II. He indicated that the appropriateness of the methodology was difficult to judge relative to the criterion of 10CFR50.46. As stated on page 8-1, FTI's SBLOCA long-term cooling methodology is basically the same as that used for LBLOCA and discussed in detail on page 8-1 of Volume I. It is repeated below.

FTI continues its transient small break LOCA computer analysis until the core is covered by mixture and the clad temperatures have decreased to the coolant saturation temperature. For the long-term, the clad will be maintained within several degrees of the coolant saturation temperature by a continuous flow of ECC water. Each plant has established NRC-approved procedures for an orderly transition to long-term cooling, assuring a continuous flow of ECC water to the reactor vessel and preventing the crystallization of boric acid in the core. The plant procedures specify the operator actions necessary to switch to sump recirculation--providing for a continuous ECC flow--and to assure a throughput of water to the core--maintaining boric acid concentrations at or below previously-established acceptable levels.

FTI plant applications performed under BAW-10168 will validate the appropriateness of previously-established operator action times, assuring the effective establishment of long-term cooling. If the need for new operator action times is demonstrated, analyses necessary to do so will be performed for and reported in the plant-specific LOCA application. For SBLOCA, such calculations are usually unnecessary, since, in general, it is bounded by LBLOCA predictions and that analysis is used to satisfy the long-term cooling criterion. In FTI's approach, the LOCA/plant procedure interface is properly addressed and in combination with as-designed plant emergency systems requirements the long-term cooling criterion of 10CFR50.46 is satisfied.

Equilibrium Core Heat Transfer Calculations: FTI's original NRC-approved evaluation model (for both large and small breaks)--BAW-10168, Revision 1--used equilibrium conditions for the RELAP5 computation of core heat transfer; this issue was thoroughly explored by the INEL reviewers and it was approved by the NRC. In Revision 2 of the EM, FRAP-T6 was deleted from the large break LOCA calculational technique. No changes were made to the core heat transfer package other than the calculations for the hot channel were now performed in RELAP5. The modeling was still based on equilibrium and it was found to be acceptable for licensing use by the NRC. In Revision 3, FRAP-T6 was deleted from SBLOCA. Again, no changes, other than code location, were made to the equilibrium core heat transfer package.

When the RSG evaluation model was originally assembled, FTI installed in RELAP5 core heat transfer correlations, covering most of the boiling curve, that were formulated based on equilibrium conditions. The RELAP5 core heat transfer package, designed after that in FRAP-T6, was used and approved for both large and small break applications. The EM was benchmarked, most recently against ROSA IV, and shown to produce conservative PCTs. FTI understands that it could upgrade RELAP5 to a nonequilibrium core heat transfer calculation, but it would require a substantial investment (code revisions, benchmarks, topical report revisions, and licensing) and there is no identified calculational or safety benefit to such a modification. Therefore, FTI has decided to continue to use the equilibrium option. The T-H role of RELAP5 is unchanged, and an equilibrium core heat transfer calculation, previously found acceptable in FRAP-T6, is still being used and has already been approved for LBLOCA calculations. The RELAP5 equilibrium approach is NRC-approved and the removal of FRAP-T6 from the SBLOCA EM has no bearing on its continued validity.

ATTACHMENT 1 to L-99-228

EVALUATION OF PROPOSED TS CHANGES

EVALUATION OF PROPOSED TS CHANGES

1.0 Introduction

The proposed amendments to Facility Operating Licenses DPR-67 for St. Lucie Unit 1 (PSL1) and NPF-16 for St. Lucie Unit 2 (PSL2) will revise the current 72-hour action completion time/allowed outage time (AOT) specified in Technical Specification (TS) 3.8.1.1, Action "b," to allow 14 days to restore an inoperable emergency diesel generator set to operable status. The proposed AOT is based on a cooperative study performed by participating members of the Combustion Engineering Owners Group (CEOG) in conjunction with supplemental information provided herein. The study included an integrated review and assessment of plant operations, deterministic design basis factors, and an evaluation of overall plant risk using probabilistic safety assessment (PSA) techniques.

2.0 Background

The NRC has been reviewing and granting improvements to technical specifications (TS) that are based, at least in part, on probabilistic risk assessment insights since the mid-1980's. In concert with this initiative, the CEOG submitted several joint application reports that provide justifications for TS AOT extensions to the NRC staff for generic review (CEOG Letter 95-344, D.F. Pilmer to NRC Document Control Desk, *C-E Owners Group Submittal of Joint Application Reports*, July 10, 1995). The justifications for these extensions are based on a balance of probabilistic and traditional engineering considerations, and risk assessments for the participating Combustion Engineering (CE) plants are contained in the reports. St. Lucie Unit 1 and Unit 2 were participating plants in that owner's group task, and the report pertinent to this submittal is CE NPSD-996, *Joint Applications Report for Emergency Diesel Generators AOT Extension*: ABB Combustion Engineering, Inc; May 1995. Supplementary information for this report is contained in the *Response to RAI Related to the CEOG Joint Applications Report for Emergency Diesel Generators, April 1997,* submitted to the NRC staff (S.L. Magruder) by owner's group letter CEOG-97-184 dated May 14, 1997. A license amendment request based, in part, on CE NPSD-996 as supplemented by the CEOG and the licensee, was approved for a participating plant in September 1998.

2.1 Emergency Diesel Generator (EDG)

Each St. Lucie unit is equipped with two seismically qualified, Class 1E, EDG sets to provide onsite emergency AC power to essential safety systems in the event of a loss of offsite power. The EDG sets for PSL1 and PSL2 are similar, with minor differences in the engine lubricating oil systems and generator ratings. Each EDG set consists of two diesel engines mounted in tandem with a 4.16 kV, 60 Hz, 3-phase, 3500 kW (3800 kW for PSL2) AC generator coupled directly between the engines. Each EDG set is complete with its own air starting system, fuel supply system, and automatic control circuitry. Descriptions of the EDG design and operation are provided in the Updated Final Safety Analysis Report (UFSAR), Section 8.3, *Onsite Power System,* for each St. Lucie unit.

Analyses demonstrate that both St. Lucie units can successfully withstand and recover from a loss of all offsite and onsite AC power in compliance with the Station Blackout (SBO) rule, 10 CFR 50.63. The SBO analysis and analysis results are described in UFSAR Section 15.2.13 for Unit 1, and UFSAR Section 15.10 for Unit 2. Additional discussion of station blackout is contained in Section 8.3 of the UFSAR for each unit.

To ensure that EDG reliability remains greater than or equal to the target reliability associated with the SBO rule, St. Lucie Plant maintains an EDG reliability program based on Regulatory Guide 1.155. The program monitors and evaluates EDG performance and reliability, requires remedial actions if one or more established reliability "trigger values" are exceeded, requires root-cause evaluation and corrective actions for individual EDG failures, and monitors EDG unavailability. In addition to the reliability program, the effectiveness of maintenance on the EDGs and support systems are monitored pursuant to the Maintenance Rule (10 CFR 50.65).

2.2 Technical Specification (TS) 3/4.8.1, Electrical Power Systems: AC Sources

The operability of AC and DC power sources and associated distribution systems during plant operation ensures that sufficient power will be available to supply the safety related equipment required for 1) the safe shutdown of the facility and 2) the mitigation and control of accident conditions within the facility. The minimum specified independent and redundant AC and DC power sources and distribution systems satisfy the requirements of General Design Criterion 17 of 10 CFR 50, Appendix A.

Limiting Condition for Operation (LCO) 3.8.1.1.b requires two separate and independent diesel generators to be operable in Modes 1, 2, 3, and 4. This redundancy ensures that at least one of the onsite AC power sources will be operable during accident conditions, coincident with an assumed loss of offsite power and single-failure of the other onsite AC power source.

If one EDG becomes inoperable during the applicable modes, Action "b" of the LCO requires, in pertinent part, the inoperable EDG to be restored to operable status within 72 hours; otherwise, the plant must transition to Hot Standby (Mode 3) within the next 6 hours and to Cold Shutdown (Mode 5) within the following 30 hours. The 72-hour AOT for one inoperable EDG is based on guidance provided in USNRC Regulatory Guide 1.93, *Availability of Electric Power Sources,* December 1974.

Action "b" contains the following additional requirements: (a) surveillance requirement 4.8.1.1.1.a must be performed within 1 hour and at least once per 8 hours thereafter (demonstrates operability of the other AC sources), (b) under certain conditions, operability of the remaining operable EDG must be demonstrated within 8 hours by verifying that it starts properly, and (c) within 2 hours, all required systems, subsystems, trains, components and devices that depend on the remaining operable diesel generator as a source of emergency power must be verified operable, and when in Modes 1, 2, or 3, the steam-driven auxiliary feedwater pump must be verified operable.

LCO 3.8.1.1 also includes independent action statements for one inoperable offsite circuit, one offsite circuit and one diesel generator inoperable, two offsite circuits inoperable, two diesel generators inoperable, and startup transformer inoperability.

2.3 Previous FPL Correspondence Related to the Proposed Amendments

FPL previously requested an AOT extension for TS 3.8.1.1, Action "b," in letter L-95-148: D.A.Sager (FPL) to NRC (DCD), Docket Nos. 50-335 and 50-389, *Proposed License Amendments, Emergency Diesel Generator AOT Extension*; June 21, 1995. The proposed license amendment would extend the AOT from 72 hours to 7 days, and provide a once-per-fuel-cycle allowance for an AOT of 10 days for a single inoperable EDG. CE NPSD-996, *Joint Applications Report for Emergency Diesel Generators AOT Extension*: ABB Combustion Engineering, Inc; May 1995, was submitted as an enclosure to the FPL letter.

FPL letter L-98-290: J.A. Stall (FPL) to NRC (DCD), Docket Nos. 50-335 and 50-389, *Withdrawal of Proposed License Amendments for LPSI and EDG Risk Informed Technical Specifications*; December 15, 1998 was issued, in part, to withdraw FPL's previous request to extend the TS 3.8.1.1, Action "b," AOT for an inoperable EDG. This letter resulted from several changes that had occurred subsequent to the original submittal: (a) the NRC staff developed a position that "once per cycle" AOTs are unnecessary and could prove cumbersome to implement, and that such proposals should be revised to include only one AOT for a single inoperable EDG that will cover all situations when the associated limiting condition for operation is applicable; (b) formal guidelines that were being developed during and after the time of FPL's submittal were issued, e.g., USNRC Regulatory Guide (RG) 1.177, *An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications*, August 1998; (c) improved input data was developed and enhancements were made to the St. Lucie PSA models; and (d) improvements to the St. Lucie plant configuration risk management process were being developed.

3.0 Description of Proposed TS Changes

The following proposed changes apply to St. Lucie Units 1 and 2. Marked-up copies of the applicable TS pages are provided in Attachment 3 and Attachment 4 of this submittal.

TS 3.8.1.1, ACTION "b" applies to the case where only one of the required separate and independent diesel generators is inoperable, and currently allows a maximum of 72 hours to restore the inoperable EDG to operable status. ACTION "b" will be revised to state, "...; restore the diesel generator to OPERABLE status within 14 days or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours." Other requirements of this action statement remain unchanged.

The associated Bases Section 3/4.8.1 will be updated with the following paragraph:

" TS 3.8.1.1, ACTION "b" provides an allowed outage/action completion time (AOT) of up to 14 days to restore a single inoperable diesel generator to operable status. This AOT is based on the findings of a deterministic and probabilistic safety analysis and is referred to as a "risk-informed" AOT. Entry into this action requires that a risk assessment be performed in accordance with the Configuration Risk Management Program (CRMP), which is described in the Administrative Procedure that implements the Maintenance Rule pursuant to 10 CFR 50.65."

4.0 Basis for Proposed TS Changes

The longer AOT will help to avert a potential unplanned shutdown by providing margin for the performance of corrective maintenance that may be needed to resolve EDG deficiencies that are discovered during equipment surveillances or scheduled preventive maintenance activities. In addition, the proposed AOT of 14 days for a single inoperable EDG will allow St. Lucie to perform preventive maintenance work on-line that currently can only be performed during shutdown.

4.1 Deterministic Assessment of the Proposed EDG AOT Extension

The St. Lucie plant onsite electric power supplies, including the onsite electric distribution systems, conform to General Design Criterion 17 (GDC-17) of 10 CFR 50, Appendix A, and have sufficient independency, redundancy, and testability to perform their safety functions assuming single failure. Each unit includes two separate and independent EDG sets to ensure that at least one onsite AC power source will be available to supply power to its associated class 1E, 4.16 kV safety bus during accident conditions, coincident with a loss of offsite power and failure of the alternate train EDG for that unit. Safety analysis assumptions are consistent with this design basis.

GDC-17 specifies design requirements, not operating requirements; it therefore does not stipulate operational restrictions on the loss of power sources. Rather, operational restrictions were established as part of the TS limiting conditions for operation, e.g., LCO 3.8.1.1, based on the intent of GDC-17 and using guidance provided in RG 1.93, *Availability of Electric Power Sources*; December 1974. The LCO is met when all the electric power sources required by GDC-17 are available; however, RG 1.93 recognized that, under certain conditions, it may be safer to continue operation at full or reduced power for a limited time rather than to effect an immediate shutdown on the loss of some of the required electric power sources. Thus, it is clear that AOTs provided in certain TS action statements are designed to permit limited operation with temporary relaxation of single-failure criterion, and at issue is the acceptability of the maximum length of the AOT interval relative to the potential occurrence of design basis events. As such, the design basis for standby EDG power is not changed by extending the present 72-hour AOT for a single inoperable EDG, but the risk-impact of EDG unavailability during the AOT interval must be addressed quantitatively in a probabilistic framework.

In the event that an EDG is inoperable in Modes 1 - 4, existing TS 3.8.1.1 requires that within two hours all required systems, subsystems, trains, components and devices that depend on the remaining operable EDG as a source of emergency power be verified operable; and when in Mode 1, 2, or 3, the steam-driven auxiliary feedwater pump must also be verified operable. This required action is intended to provide assurance that a loss of offsite power event will not result in a complete loss of safety function of critical systems during the period one of the EDGs is inoperable.

In the event that all Unit 1 offsite and onsite power sources fail, i.e., station blackout (SBO), power will be supplied from a Unit 2 EDG to one of the Unit 1 class 1E, 4.16 kV safety busses via the station blackout cross-tie. The SBO Crosstie connects the two safety-related 4.16 kV "swing" busses between the units. Each of the Unit 2 EDGs is capable of powering its dedicated division of safety loads in addition to the complement of selected Unit 1 loads necessary to maintain Unit 1 in Hot Standby through the duration of the SBO event. In contrast, the SBO analysis for Unit 2

demonstrates a four-hour DC coping duration, and use of a Unit 1 EDG is not credited in the Unit 2 coping analysis. However, power from a Unit 1 EDG can be provided to a Unit 2 safety-related buss via the SBO Crosstie for the purpose of augmenting the DC coping program. Mitigation of an SBO event is controlled by plant-specific Emergency Operating Procedures, and, for the SBO duration, the plant is capable of maintaining adequate core cooling and containment integrity.

The SBO analysis does not consider the availability of offsite power to the alternate unit. However, if offsite power is available to the alternate unit during an SBO event at either PSL1 or PSL2, the SBO Crosstie may be used to provide offsite power from the unaffected unit to the affected unit. The assumptions and the results of the SBO analysis are not changed by an extension of the AOT, and compliance with 10 CFR 50.63 will be maintained. In addition, the St. Lucie Plant EDG Reliability Program ensures that EDG reliability is maintained at or above the SBO target level, and the effectiveness of maintenance on the EDGs and support systems is monitored pursuant to the Maintenance Rule (10 CFR 50.65).

Based on the above discussion, extending the AOT for a single inoperable EDG from 72 hours to 14 days is acceptable with regard to the principle that adequate plant design defense-in-depth and safety margins are maintained. A generic discussion of deterministic factors associated with EDG unavailability is also provided in Section 6.2 of CE NPSD-996. The St. Lucie plant-specific impact from extending the AOT and potential EDG unavailability is evaluated in a probabilistic framework and is discussed in section 4.2 of this attachment.

4.2 Probabilistic Safety Assessment (PSA) of the Proposed EDG AOT Extension

The St. Lucie contribution to the 1995 preparation of CE NPSD-996 was generated using the IPE models developed in response to Generic Letter (GL) 88-20, *"Individual Plant Examination for Severe Accident Vulnerabilities"*, and associated supplements. Since submittal of the IPE, both the models and the reliability/unavailability databases for St. Lucie Units 1 and 2 have been updated. The updated models and databases were then used to re-calculate the risk numbers for each unit to evaluate the extended EDG AOT. The model update process included a review of all plant design changes that were implemented since creation of the original models. A summary of the St. Lucie PSA changes since submittal of the IPE is included in section 4.2.1.4 of this attachment.

FPL's evaluation of the risk associated with the proposed AOT generally conforms to the three-tiered approach that is identified in Regulatory Position C.2.3 of USNRC Regulatory Guide 1.177, *An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications*, August 1998. Tier 1 consists of the PSA capability and insights; Tier 2 identifies risk-significant plant configurations that should be avoided; and Tier 3 describes a risk-informed configuration risk management program.

4.2.1 Tier 1, Analysis of Risk Impact and Calculated Results

Tier 1 is an evaluation of the impact on plant risk of the proposed TS change as expressed by the change in core damage frequency (CDF), the incremental conditional change in core damage probability (ICCDP), and when appropriate, the change in large early release frequency (LERF) and the incremental conditional large early release probability (ICLERP).

Section 6.3.2 of CE NPSD-996 discusses a series of PSA sensitivity studies that were performed to assess the "at-power" risk increment resulting from an extended EDG AOT. The types of sensitivity studies performed for CE NPSD-996 were developed with input from the NRC staff. The original results of these Tier 1 evaluations were documented in Tables 6.3.2-1, 6.3.2-2, and 6.3.2-3, for each of the participating CE utilities.

This proposed license amendment provides revised St. Lucie Units 1 and 2 EDG AOT PSA sensitivity study results based on the updated PSA models, and supercedes the data provided in CE NPSD-996, Tables 6.3.2-1, 6.3.2-2, and 6.3.2-3. The revised results are shown in Tables 1, 2, and 3, respectively. For the purpose of convenience, corresponding (superceded) data from Tables 6.3.2-1, 6.3.2-2, and 6.3.2-3 of CE NPSD-996 are shown in parentheses.

Table 1

AOT CONDITIONAL CDF CONTRIBUTIONS FOR EDGs - Corrective Maintenance

(CE NPSD-996, Table 6.3.2-1 superseded values are shown in parentheses)

Parameter	St. Lucie Unit 1		St. Lucie Unit 2	
EDG Success Criteria	1 of 2		1 of 2	
Current AOT, days	3		3	
Proposed AOT, days	14	(10)	14	(10)
Conditional CDF, per yr., 1 EDG unavailable	2.14E-05	(5.9E-05)	1.83E-05	(6.3E-05)
Conditional CDF, per yr., 1 EDG train not out for T/M	1.39E-05	(2.1E-05)	1.23E-05	(2.3E-05)
Increase in CDF, per yr.	7.50E-06	(3.8E-05)	6.00E-06	(4.0E-05)
Single AOT Risk, Current full AOT	6.16E-08	(3.1E-07)	4.93E-08	(3.3E-07)
Single AOT Risk, Proposed full AOT	2.87E-07	(1.0E-06)	2.30E-07	(1.1E-06)
Downtime Frequency, events/yr/train	1	(2.5)	1	(2.5)
Yearly AOT Risk, Current full AOT, per yr.	1.23E-07	(7.8E-07)	9.86E-08	(8.2E-07)
Yearly AOT Risk, Proposed full AOT, per yr.	5.75E-07	(1.8E-06)	4.60E-07	(1.9E-06)
Mean Duration, hrs/event	24		24	
Single AOT Risk for Mean Duration	2.05E-08	(1.0E-07)	1.64E-08	(1.1E-07)
Yearly AOT Risk for Mean Duration, per yr.	4.11E-08	(2.6E-07)	3.29E-08	(2.7E-07)

Table 2

AOT CONDITIONAL CDF CONTRIBUTIONS FOR EDGs - Preventive Maintenance

(CE NPSD-996, Table 6.3.2-2 superseded values are shown in parentheses)

Parameter	St. Lucie Unit 1		St. Lucie Unit 2	
EDG Success Criteria	1 of 2		1 of 2	
Current AOT, days	3		3	
Proposed AOT, days	14	(10)	14	(10)
Conditional CDF, per yr., 1 EDG unavailable	1.89E-05	(4.1E-05)	1.58E-05	(4.7E-05)
Conditional CDF, per yr., 1 EDG not out for T/M	1.39E-05	(2.1E-05)	1.23E-05	(2.3E-05)
Increase in CDF, per yr.	5.00E-06	(2.0E-05)	3.50E-06	(2.4E-05)
Single AOT Risk, Current full AOT	4.11E-08	(1.6E-07)	2.87E-08	(2.0E-07)
Single AOT Risk, Proposed full AOT	1.92E-07	(5.4E-07)	1.34E-07	(6.6E-07)
Downtime Frequency, events/yr/train	2	(2.8)	2	(2.8)
Yearly AOT Risk, Current full AOT, per yr.	1.64E-07	(4.6E-07)	1.15E-08	(5.5E-07)
Yearly AOT Risk, Proposed full AOT, per yr.	7.67E-07	(1.1E-06)	5.37E-07	(1.3E-06)
Proposed Downtime, hrs/yr/train	208	(240)	208	(240)
Mean Duration, hrs/event	104	(86)	104	(86)
Single AOT Risk for Mean Duration	5.93E-08	(2.0E-07)	4.15E-08	(2.4E-07)
Yearly AOT Risk for Mean Duration, per yr.	2.37E-07	(5.5E-07)	1.66E-07	(6.6E-07)

Table 3

PROPOSED AVERAGE CDF

(CE NPSD-996, Table 6.3.2-3 superseded values are shown in parentheses)

Parameter	St. Lucie Unit 1		St. Lucie Unit 2	
EDG Success Criteria	1 of 2		1 of 2	
Present AOT, days	3		3	
Proposed AOT, days	**14**	(10)	**14**	(10)
Proposed Downtime, hrs/train/yr	**232**	(264)	**232**	(264)
Average CDF, base, per yr.	**1.39E-05**	(2.14E-05)	**1.23E-05**	(2.35E-05)
Proposed Average CDF, per yr., using EDG T/M set at Proposed Downtime value	**1.41E-05**	(2.2E-05)	**1.24E-05**	(2.4E-05)

In addition to the CDF calculations, FPL determined the change in LERF (Table 4), and calculated the ICCDP (Table 5) and ICLERP (Table 6) for comparison to acceptance guidelines defined in (a) RG 1.174, *An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant Specific Changes to the Licensing Basis*, and (b) RG 1.177.

Table 4

PROPOSED AVERAGE LERF

	Early Containment Failure Probability = 0.01 (baseline)		* Early Containment Failure Probability = 0.1	
Parameter	St. Lucie Unit 1	St. Lucie Unit 2	St. Lucie Unit 1	St. Lucie Unit 2
Avg. LERF, base, per yr.	**3.37E-06**	**5.98E-06**	**4.59E-06**	**7.07E-06**
Proposed LERF, per yr, using EDG T/M set at proposed downtime value	**3.38E-06**	**5.99E-06**	**4.62E-06**	**7.08E-06**

* Sensitivity evaluation (factor of 10 increase)

Table 5

ICCDP RESULTS
(Calculated using RG 1.177 methodology)

Parameter	St. Lucie Unit 1	St. Lucie Unit 2
ICCDP for Corrective Maintenance (CM) case	2.87E-07	2.30E-07
ICCDP for Preventive Maintenance (PM) case	1.92E-07	1.34E-07

Table 6

ICLERP RESULTS
(Calculated using RG 1.177 methodology)

	Early Containment Failure Probability = 0.01 (baseline)		* Early Containment Failure Probability = 0.1	
Case	St. Lucie Unit 1	St. Lucie Unit 2	St. Lucie Unit 1	St. Lucie Unit 2
CM	4.22E-09	4.99E-09	2.99E-08	2.53E-08
PM	2.68E-09	3.84E-09	1.99E-08	1.57E-08

* Sensitivity evaluation (factor of 10 increase)

It can be seen from the data in Tables 3 and 4 that the calculated increase in CDF is less than 1E-06 per reactor year and the calculated increase in the LERF is less than 1E-07 per reactor year, respectively. Thus, the RG 1.174 acceptance guideline of "very small" increases in these parameters is satisfied.

In addition, the calculated ICCDP (Table 5) is less than 5E-07 and the calculated ICLERP (Table 6) is less than 5E-08, and satisfy the acceptance guideline that the proposed AOT change has only a "small" quantitative impact on plant risk as defined in RG 1.177.

4.2.1.1 Modeling Adequacy and Completeness Relative to this Application. The results of the evaluations performed in support of the St. Lucie proposed EDG AOT extension were reviewed by two PSA engineers (a preparer and an independent reviewer) from FPL's Nuclear Engineering Reliability and Risk Assessment Group. Both concluded that the results were appropriate considering the inputs and assumptions used, and based on a review of the dominant cutsets, that the results are reasonable and the models are adequate for this application. The following summarizes the dominant cutsets:

Attachment 1-A lists the top 10 Unit 1 baseline cutsets. The CDF is reflected in Tables 1 and 2 as the "Conditional CDF, per year, 1 EDG not out for T/M". The dominant cutsets are related to a "Small-Small" (1/2" to 3") LOCA initiating event with failures related to high pressure safety injection/recirculation. Other cutsets in the top 10 are related to ATWS.

Attachment 1-B lists the top 10 Unit 1 cutsets for the corrective maintenance (CM) case. This CDF is reflected in Table 1 as the "Conditional CDF, per year, 1 EDG unavailable". For this case, one EDG train is assumed out-of-service for corrective maintenance and the common cause EDG failures are set to the beta factor. In addition to the cutsets related to a "Small-Small" LOCA initiating event (same as baseline), loss of grid with EDG failure/unavailability cutsets are now in the top 10. The dominant EDG cutset is loss of grid with a common cause EDG failure. Other EDG related cutsets consist of a loss of grid, one EDG out-of-service for maintenance, and an independent failure of the other EDG.

Attachment 1-C lists the top 10 Unit 1 cutsets for the preventive maintenance (PM) case. The CDF is reflected in Table 2 as the "Conditional CDF, per year, 1 EDG unavailable". For this case, one EDG is assumed out-of-service for preventive maintenance and the common cause EDG failures are set to 0.0. Eight of the top ten cutsets are the same as the baseline case. The remaining two top 10 cutsets are related to a loss of grid, one EDG out-of-service for maintenance and failure of the other EDG to start or run.

Attachment 1-D lists the top 10 Unit 1 cutsets for the new average CDF assuming the proposed EDG downtime. The CDF is reflected in Table 3 as the "Proposed Average CDF, per yr., using EDG T/M set at Proposed Downtime Value". For this case, the EDG unavailability was changed based on the proposed downtime assuming an increased AOT. The dominant sequences are the same as the baseline case.

Attachment 1-E lists the top 10 Unit 2 baseline cutsets. The CDF is reflected in Tables 1 and 2 as the "Conditional CDF, per year, 1 EDG not out for T/M". The dominant cutsets are related to a "Small-Small" LOCA with failures related to high pressure safety injection/recirculation.

Attachment 1-F lists the top 10 Unit 2 cutsets for the CM case. The EDG related cutsets are similar to those discussed for the Unit 1 CM case.

Attachment 1-G lists the top 10 Unit 2 cutsets for the PM case. The EDG related cutsets are similar to those discussed above for the Unit 1 PM case.

Attachment 1-H lists the top 10 Unit 2 cutsets for the new average CDF assuming the proposed EDG downtime. The dominant cutsets are the same as the Unit 2 baseline case.

4.2.1.2 Internal Fires and External Events. The PSA models used to calculate the estimated risk impact of the proposed AOT extension do not include an assessment of the potential risk due to internal fires and external events. The St. Lucie response to GL 88-20, Supplement 4 (*"Individual Plant Examination of External Events for Severe Accident Vulnerabilities"* (IPEEE)) concluded that there were no severe accident vulnerabilities due to internal fires and external events. It is judged that any potential impact the AOT extension might have on the risk due to internal fires and external events would be very small and remain well below the acceptance criteria.

The required action in response to external events is well proceduralized. The following is a summary of applicable plant procedures that address plant actions in response to external events (e.g., hurricanes, tornadoes, fires):

The Administrative Procedure entitled "Hurricane Season Preparation" outlines the actions to be reviewed prior to the start of hurricane season.

The Administrative Procedure entitled "Severe Weather Preparations" provides instructions to be followed to prepare for severe weather (including tornadoes) or in response to a hurricane watch or warning. Actions to be taken include, but are not limited to:

- Installing intake structure missile shielding if removed,
- Topping off the diesel oil storage tanks,
- Removing the stoplogs from storage and preparing them for installation,
- Surveying the plant site, removing trash and debris, and securing loose equipment,
- Closing Reactor Auxiliary Building outside doors and roof hatches, and
- Placing station batteries on equalizing charge.

The Administrative Procedure entitled "Hurricane Staffing" provides instructions for staffing in preparation for a hurricane.

The Emergency Plan Implementing Procedure entitled "Duties and Responsibilities of the Emergency Coordinator" provides the criteria for unit shutdown if a hurricane warning is in effect, and either one or both Unit(s) is/are in Mode 1, 2 or 3. The shutdown criteria is as follows:

- For storms projected to reach Category 1 or 2, the unit(s) shall be placed in HOT STANDBY (Mode 3) or below at least two (2) hours before the projected onset of sustained hurricane force winds at the site, and both units shall remain off-line for the duration of the hurricane force winds (or restoration of reliable offsite power).

- For storms projected to reach Category 3, 4 and 5 prior to landfall, the units shall be shut down to a temperature less than 350 degrees Tave at least two (2) hours before the projected onset of sustained hurricane force winds at the site, and both units shall remain off-line for the duration of the hurricane force winds (or restoration of reliable offsite power).

The Emergency Plan Implementing Procedure entitled "Classification of Emergencies" provides instructions for the classification of emergencies at the St. Lucie plant. The procedure includes criteria for emergency classification of events related to hurricanes, tornadoes, abnormal water level, and fires.

The Off-Normal Operating Procedure entitled "Response to Fire" provides operator actions for responding to a fire at each St. Lucie Unit. These procedures provide specific guidance to the operator for performing a safe shutdown fire impact assessment and direction as to which mode to place the unit in if the fire challenges continued unit operation or stable plant conditions. Additional procedures provide fire-fighting strategies to assist the fire brigade in combating a fire.

4.2.1.3 Sensitivity/Uncertainty Analysis. An additional study was performed to assess the sensitivity of the risk impact of an extended EDG AOT to changes in offsite power and select Human Reliability Analysis (HRA) non-recovery probabilities. The events chosen for this study were based on review of the St. Lucie IPE SER (*NRC Staff Evaluation Report of St. Lucie Units 1 and 2 Individual Plant Examination (IPE) Submittal* – (TAC Nos. M74473 and M74474), July 21, 1997) in conjunction with engineering judgement to determine which events are associated with recovery of an EDG or the functions impacted due to loss of an EDG. It is judged that appropriate uncertainty issues are addressed by the sensitivity studies, the scope and results of which are described in the following sub-sections.

4.2.1.3.1 Offsite Power Recovery Events. The St. Lucie IPE SER states, "It appears that, in comparison to NSAC-147 data, the offsite power recovery factors are optimistic and will considerably impact the results." A comparison of non-recovery probabilities for two assumed times after the initiating event was provided, and the NSAC values were 1.4 to 2.8 times higher than the IPE values. Based on this comparison, it is judged that increasing the non-recovery probability for all offsite power recovery events by a factor of two would be adequate for this sensitivity study.

4.2.1.3.2 Selected HRA Events Re-Quantified as Time-Dependent Actions. The St. Lucie IPE SER also discussed potential problems with treating HRA events as time-independent, and concluded that treating post initiator human actions with a time-independent approach is troublesome since the approach does not model diagnosis and decision making and has the potential to over-estimate the likelihood of success. It was also noted that the quantification of the non-recovery probability for many actions was not sequence specific, i.e., the same probability was used for all sequences thus not considering potential differences in time for diagnosis and the available time to complete the action. Although, in many cases, the actions listed below may not be specifically related to an EDG being out of service (OOS), they could have an impact on the overall PSA results and were therefore selected for consideration in this study. The HRA events considered were:

RTOP1ROTC (RTOP2ROTC) - Operator Fails to Initiate Once-Through Cooling for SGTR
RTOP1TOTC (RTOP2TOTC) - Operator Fails to Initiate Once-Through Cooling [for Transients]
RTOP1S1OTC (RTOP2S1OTC) - Operator Fails to Initiate Once-Through Cooling for S1 LOCA
RTOP1S1RCP (RTOP2S1RCP) - Operator Fails to Secure RCPs Following Loss of Seal Cooling

The timing for once-through-cooling (OTC) initiation could be scenario specific. The most limiting case would be a total loss of main feedwater resulting in a unit trip on low SG level. OTC must be initiated before SG dryout (approximately 19-20 minutes). The initiating events (IEs) of concern are those related to loss of main feedwater (MFW) (trip on low SG level). For other IEs, the reactor trip would occur with at least normal operating SG level, and thus the available time to initiate OTC would be lengthened. For some scenarios, the initiation of OTC may be several hours after shutdown, when the decay heat is substantially lower than immediately after the trip.

Evaluation of sequence specific OTC non-recovery probabilities has not yet been performed. Representative, conservative timing assumptions were used for this sensitivity study. Applying the time-dependent technique used for the PSL IPE and assuming 20 minutes to SG dryout, a conservative 15 minute diagnosis time (thus 5 minutes available), and a 2 minute response time, the estimated non-recovery probability would be approximately 2E-02. This timing would actually only apply to the t=0 loss of all feedwater events (i.e., reactor trip on low SG level). For longer-term loss of feedwater scenarios, the available time would be lengthened. For this study, a conservative value of 5E-02 for all OTC recovery events is used. The benefit of sequence specific quantification of OTC recovery events will be evaluated as part of a future PSA update.

Action RTOP1S1RCP (RTOP2S1RCP) involves the operator securing the Reactor Coolant Pumps (RCP) after loss of component cooling water (CCW) cooling to the pump seals. It is assumed that the pumps must be secured within 10 minutes to prevent a seal LOCA, although industry events have shown that the pumps could operate longer than 10 minutes without catastrophic seal damage. This event was assumed to be time-independent for the PSL IPE. For this study, however, it was assumed that this is a time-dependent in-control room response action requiring 3 minutes to diagnose (thus a 7 minute available time) and a 1 minute response time. The resulting non-recovery probability would be approximately 7E-03. For this study, a conservative value of 1E-02 was used. It should be noted that for sequences related to the EDGs (i.e., loss of offsite power events), the RCPs would be secured without operator action whether or not seal cooling is available.

The non-recovery probabilities used in this study for the above HRA events are summarized in Table 7.

Table 7

SUMMARY OF HRA NON-RECOVERY PROBABILITY CHANGES

Basic Event	Description	Baseline Probability	Probability used in Study	Factor Increase from Baseline
RTOP1ROTC (RTOP2ROTC)	OPERATOR FAILS TO INITIATE ONCE-THROUGH COOLING FOR SGTR	7.5E-03	5E-02	6.7
RTOP1TOTC (RTOP2TOTC)	OPERATOR FAILS TO INITIATE ONCE-THROUGH COOLING [FOR TRANSIENTS]	7.5E-03	5E-02	6.7
RTOP1S1OTC (RTOP2S1OTC)	OPERATOR FAILS TO INITIATE ONCE-THROUGH COOLING FOR S1	7.5E-03	5E-02	6.7
RTOP1S1RCP (RTOP2S1RCP)	OPERATOR FAILS TO SECURE RCPS FOLLOWING LOSS OF SEAL	7.5E-03	1E-02	1.3

4.2.1.3.3 <u>Sensitivity of the Non-recovery Probability of Select HRA Events.</u> Although not specifically addressed in the St. Lucie IPE SER, the following recovery events (associated with recovery of an EDG or functions impacted due to loss of an EDG) were judged to have a potential impact on the risk of the unavailability of an EDG:

R#CAFWMAN (R#CAFWMAN)-Operator Fails to Manually Start C AFW PP

This action involves manual-local operation of the "C" (steam driven) Auxiliary Feedwater (AFW) pump. The action is primarily associated with loss of DC control power to the pump. The dominant method of losing power would be battery depletion following loss of AC power to the battery chargers or charger failure. Battery depletion would be at least 4 hours after loss of the chargers. Decay heat levels would be less than immediately after a unit trip. The available time to recovery feedwater would thus be greater than the 60 minutes assumed for a t=0 loss of all feedwater. This basic event was originally quantified as an ex-control room action with a 10 minute diagnosis time, a 13 minute response time, and 50 minutes available time (assuming 60 minutes to recover feedwater). If it is assumed that an additional 10 minutes is required for diagnosis (20 minutes total), 40 minutes would then be available to complete the action. This results in a revised probability of 0.12. For this study, a conservative value of 0.2 is used.

R#DC-AB (R#DCAB) - OPERATOR FAILS TO REALIGN 'AB' DC BUS

This action involves re-alignment of the swing "AB" DC bus from one train (either "A" or "B") to the other train following loss of power to the train to which the "AB" bus is initially aligned. Re-alignment of the "AB" bus is required to maintain power to the "C" AFW pump. This is a control room action that should take no more than 3 minutes to complete. The dominant method of losing power would be battery depletion following loss of AC power to the battery chargers or charger failure. Battery depletion would be at least 4 hours after loss of the chargers. Decay heat levels would be less than immediately after a unit trip. The available time to recover feedwater would thus be greater than the 60 minutes assumed for a t=0 loss of all feedwater. A conservative value of 0.1 was used for this study (baseline value is 9.1E-03).

R#DGFO (R#DGFO) - OPERATOR FAILS TO RECOVER EDG BY OPENING DG FILL VALVE

Failures associated with the EDG fuel oil (FO) system were considered as "start" failures in the IPE model. EDG FO failures were changed to "run" failures as part of the PSA update, since the EDGs can operate at least 45 minutes without makeup from the EDG FO storage tank. This recovery event was quantified as a time related ex-control room action. The timing was counted from t=0 (i.e., from the start of the sequence). The queue should actually be from receipt of a low level alarm on the EDG FO Day Tank (this conservatively assumes that the operator is not monitoring proper FO transfer). Since loss of FO (and subsequent loss of the EDG) is at least approximately 45 minutes after start of the event, decay heat levels would be less than those immediately after a trip and the time to core uncovery would be somewhat longer than the 60 min. assumed in the original evaluation. The original basic event quantification assumed a 10 minute response time with 55 min. available for a resulting probability of 3.68E-02. If the response time is increased to 15 min. and the available time is conservatively left at 55 min., the new probability would be 8.64E-02. For this sensitivity study, a conservative value of 0.1 is judged to be bounding.

R#HFDG (R#HFDG) - OPERATOR FAILS TO RECOVER IMPROPERLY ALIGNED EDG

This action involves failure to recover an improperly aligned EDG, and is an ex-control room action performed local to the EDG. A conservative 20 minute diagnosis time, a conservative 20 minute response time, with an available time of 40 minutes (assumes that EDG must be recovered in 60 minutes) results in a non-recovery probability of approximately 0.23. A value of 0.5 was used for this study.

R#RESET (R#RESET) - OPERATOR FAILS TO DIAGNOSE MAIN GEN. LOCKOUT, RESET AND MANUALLY ENERGIZE S/UP

This action involves failure to manually switch electrical busses from the Auxiliary to the Startup Transformers following failure of the main generator lockout relay signal, and was quantified as an in-control room time-dependent action. 30 minutes was assumed for diagnosis leaving a 30 minute available time. A 10 minute response time was assumed. It is judged that the baseline non-recovery probability (8.77E-02) for this action is appropriate.

R#AFXVLVS (R#AFXVLVS) - OPER FAILS TO UTILIZE AFW X-CONNECT VLVS

This action involves opening (locally) AFW cross-connect valves after failure of a motor driven AFW pump on one train and the failure of the AFW flow path to the SG on the other train. This action was quantified assuming a 10 minute response time and 55 minute available time. For this study, the response time was increased to 15 minutes and the available time was reduced to 50 minutes. This results in a non-recovery probability of approximately 0.1 (baseline is 3.68E-02).

The non-recovery probabilities used in this study for the preceding events are summarized and compared to their associated baseline values in Table 8.

Table 8

SUMMARY OF EDG-RELATED RECOVERY EVENT NON-RECOVERY PROBABILITY CHANGES

Basic Event	Description	Baseline Probability	Probability used in study	Factor Increase from Baseline
R#CAFWMAN (R#CAFWMAN)	OPERATOR FAILS TO MANUALLY START C AFW PP PER EOP-99, APP. G	7.88E-02	0.2	2.5
R#DC-AB (R#DCAB)	OPERATOR FAILS TO REALIGN 'AB' DC BUS	9.1E-03	0.1	11.0
R#DGFO (R#DGFO)	OPERATOR FAILS TO RECOVER EDG BY OPENING DG FILL VALVE	3.68E-02	0.1	2.7
R#HFDG (R#HFDG)	OPERATOR FAILS TO RECOVER IMPROPERLY ALIGNED EDG	0.1	0.5	5.0
R#RESET (R#RESET)	OPERATOR FAILS TO DIAGNOSE MAIN GEN. LOCKOUT, RESET AND MANUALLY ENERGIZE S/UP	8.77E-02	BASELINE	1.0
R#AFXVLVS (R#AFXVLVS)	OPER FAILS TO UTILIZE AFW X-CONNECT VLVS	3.68E-02	0.1	2.7

The ICCDP based on the cumulative impact of the recovery action non-recovery probability change sensitivity study discussed above is >5E-07 except for the Unit 2 PM case, which is <5E-07 (Table 9). The largest calculated ICCDP is only approximately 1.1E-06. Considering the very conservative values used for this sensitivity study and results showing that the ICCDP is still only approximately 1E-06 or less, the proposed AOT change is judged to be not risk significant.

The ICLERP is <5E-08 assuming the baseline early containment failure probability of 0.01 (Table 10). Assuming a factor of 10 increase in the early containment failure probability (0.1), the ICLERP is >5E-08 except for the Unit 2 PM case. The largest calculated ICLERP is only approximately 1.15E-07. Considering the conservatism in the values used, including the factor of 10 increase in the early containment failure probability, this sensitivity case demonstrates that the proposed change is not risk significant.

The average change in CDF is 5E-07 or less and the average change in LERF is 5E-08 or less (Table 11). Both of these values are within Region III of RG 1.174 Figures 3 and 4, respectively, and are thus considered very small.

Table 9

ICCDP RESULTS FOR RECOVERY ACTION NON-RECOVERY PROBABILITY CHANGE SENSITIVITY STUDY

Case	Unit 1	Unit 2
CM	1.07E-06	8.47E-07
PM	6.63E-07	4.37E-07

Table 10

ICLERP RESULTS FOR RECOVERY ACTION NON-RECOVERY PROBABILITY CHANGE SENSITIVITY STUDY

	Using Early Containment Failure Probability = 0.01		Using Early Containment Failure Probability = 0.1	
Case	Unit 1	Unit 2	Unit 1	Unit 2
CM	1.95E-08	8.43E-09	1.15E-07	8.5E-08
PM	1.46E-08	4.6E-09	7.32E-08	4.37E-08

Table 11

AVERAGE CHANGE IN CDF AND LERF FOR RECOVERY ACTION NON-RECOVERY PROBABILITY CHANGE SENSITIVITY STUDY

(for comparison to RG 1.174 criteria)

Parameter	St. Lucie Unit 1		St. Lucie Unit 2	
Change in CDF	5E-07		4E-07	
	Early Containment Failure Prob = 0.01	Early Containment Failure Prob = 0.1	Early Containment Failure Prob = 0.01	Early Containment Failure Prob = 0.1
Change in LERF	1E-08	5E-08	1E-08	4E-08

4.2.1.3.4 Consideration of Cumulative Impact of Risk-Informed AOTs. FPL has also submitted a proposed license amendment for a risk-informed AOT extension (from 3 to 7 days) for the St. Lucie plant Low Pressure Safety Injection (LPSI) System (FPL Letter L-99-079, J.A. Stall (FPL) to NRC (DCD), St. Lucie Unit1 and Unit 2, Docket Nos. 50-335 and 50-389, Proposed License Amendments, *LPSI System Risk Informed AOT Extension;* June 1, 1999). Accordingly, the cumulative impact on the average CDF of both the proposed EDG and LPSI AOT changes (including the recovery action non-recovery probability sensitivity study changes discussed above) was evaluated and found to be 7E-07 or less (Table 12). The average change in LERF is 7E-08 or less (Table 12). Both of these values are within Region III of RG 1.174 Figures 3 and 4, respectively, and are thus considered very small.

Table 12

AVERAGE CHANGE IN CDF AND LERF FOR
RECOVERY ACTION NON-RECOVERY PROBABILITY CHANGE SENSITIVITY STUDY
WITH PROPOSED LPSI UNAVAILABILITY FROM LPSI AOT CHANGE PLA
(for comparison to RG 1.174 Criteria)

Parameter	St. Lucie Unit 1		St. Lucie Unit 2	
Change in CDF	7E-07		5E-07	
	Early Containment Failure Prob = 0.01	Early Containment Failure Prob = 0.1	Early Containment Failure Prob = 0.01	Early Containment Failure Prob = 0.1
Change in LERF	2E-08	7E-08	1E-08	5E-08

4.2.1.4 Quality of the St. Lucie PSA. The models used for this application were generated using the IPE models developed in response to Generic Letter (GL) 88-20, *Individual Plant Examination for Severe Accident Vulnerabilities*, and associated supplements. The original development work was classified and performed as "Quality Related" under the FPL 10 CFR 50, Appendix B quality assurance (QA) program. The revision and applications of the PSA models and associated databases continue to be handled as Quality Related.

Administrative controls include written procedures, independent review of all model changes, data updates and risk assessments performed using PSA methods and models. Risk assessments are performed by a PSA engineer, independently reviewed by another PSA engineer, and approved by the Department Head or designee. The Reliability and Risk Assessment Group (RRAG) is required to follow the FPL Nuclear Engineering Quality Instructions (QI) with written procedures derived from those QIs. Procedures, risk assessment documentation, and associated records are controlled and retained as QA records.

Since the approval of the IPE, the RRAG has maintained the PSA models consistent with the current plant configuration such that they are considered "living" models. The PSA models are updated for different reasons, including plant changes and modifications, procedure changes, accrual of new plant data, discovery of modeling errors, advances in PSA technology, and issuance of new industry PSA standards. The update process ensures that the applicable changes are implemented and documented in a timely manner so that risk analyses performed in support of plant operations reflect the current plant configuration, operating philosophy, and transient and component failure history. The PSA maintenance and update process is described in the RRAG Standard entitled, *Probability Safety Assessment Update and Maintenance Procedure*. This standard defines two types of periodic updates: 1) a data analysis update, and 2) a model update. The data analysis update is performed at least every five years. Model updates consist of either single or multiple PSA changes and are performed at a frequency dependent on the estimated impact of the accumulated changes. Guidelines to determine the need for a model update are provided in the standard.

4.2.1.4.1 PSA Software. All computer programs that process PSA model inputs are verified and validated as needed. The RRAG policy on verification and validation of QA controlled/procured software, as well as the verification and validation for software and computers when used for Quality Related applications are described in the RRAG Standard entitled, *Probability Safety Assessment Software Control Procedure*. This standard provides a list of all the software used by the RRAG and indicates whether the software is QA controlled/procured. Software verification is the process used to ensure the software meets the software requirement specifications. The PSA software that is procured with a QA option and is developed under a 10 CFR 50, Appendix B, QA program does not require further software verification by the RRAG. However, the PSA software, which is not procured with a QA option can be verified by comparison of results to previously approved software.

Validation of software is performed for different conditions such as: 1) a new installation of software, 2) any new database or configuration file changes issued by the RRAG, 3) unreasonable results, 4) change in computer configuration (software, hardware), and 5) use of software for Quality Related applications for the first time. Validation requirements for each Quality Related PSA computer program are documented in a Software Verification/Validation Plan (SVVP) procedure. These requirements include the method of validation, the frequency of validation, the documentation required and the acceptance criteria. A SVVP procedure is submitted for each program. Actual validation benchmark problems can exercise more than one program, but a separate Software Verification/Validation Report (SVVR) must be submitted for each program. Each SVVP procedure and SVVR is independently reviewed and then approved by the RRAG supervisor. Software validation tests both the software and the hardware. Validation tests are also performed following any significant change in the hardware, operating system, or program, or if the validation period established in the SVVP procedure expires

4.2.1.4.2 Model Changes Since Submittal of the IPE. The last three years of data gathered pursuant to the Maintenance Rule (10 CFR 50.65) was used for the reliability/unavailability database update. This ensured concise, high-quality unavailability and reliability data for the risk-significant systems. Prior to performing the risk assessment for this proposed license amendment, all design changes implemented since the last PSA update, and current revisions of the critical procedures that establish requirements and timing for operator recovery actions were reviewed. Changes to the PSA were not required as a result of this review.

A summary of significant model changes incorporated since the IPE submittal follows:

The most significant change included with each model update is the creation of a "one-top" model which is constructed from the original model's individual top events for various initiators, e.g., small LOCA, large LOCA, SGTR, reactor trips, etc. The one-top model allows rapid quantification, and each case for this EDG risk assessment was individually quantified. The truncation used for quantification was 5E-10 or lower. This replaces the use of one master cutset file (per unit) in the CE NPSD-996 evaluation.

Test & Maintenance (T&M) events for selected equipment were added to better support Maintenance Rule implementation and related risk evaluations. Minor improvements were made in the modeling of instrument air systems and in the handling of common cause events.

New initiating event (IE) frequencies were calculated for all LOCAs. This was done in accordance with CEOG Probabilistic Safety Assessment Working Group (PSAWG) Technical Position Paper, *"Evaluation of the Initiating Event Frequency for the Loss of Coolant Accident"*, CEOG Task 941, January 1997. Although the IE frequency for two LOCA sizes (large and small) decreased, the net impact was an increase in the total LOCA IE frequency of nearly 48%, i.e., from 2.09E-3 to 3.09E-3 per year.

The loss of grid IE frequency used for the St. Lucie IPE was 0.15/yr based on generic data. Actual data for the 20 years since Unit 1 startup show only two loss of grid events impacting St. Lucie. This corresponds to a 0.1/yr IE frequency. 0.1/yr was used for the PSA update.

The process of adding recoveries is now automated using a recovery "rule file". The rule file utilizes a manual recovery action process in that recovery actions are added to each cutset rather than being generated from the model, but the process is automated such that all the similar cutset scenarios are recovered automatically. This automatic feature ensures uniform and complete inclusion of recovery actions throughout all of the generated cutsets, and yields more realistic and consistent results.

All offsite power recovery cases were re-evaluated for both St. Lucie units. One case was added to the Unit 1 analysis for recovery of offsite power in 9 hours (approximately 1 hour before the Unit 1 CST would deplete without condensate replenishment). The non-recovery probability for one case was increased for both units due to an incorrect assumption that was used in the original analysis. In addition, the related recovery for getting power from the alternate unit was increased due to timing considerations. Although 60 minutes total is available (as assumed in the original evaluation), only 45 minutes remains for power recovery after diagnosis of the event per the plant Emergency Procedures. This factor was combined with hardware-related failures to calculate the total non-recovery probability of 0.1 for the crosstie recovery event.

As discussed in the St. Lucie IPE submittal (FPL Letter L-93-301, D.A. Sager (FPL) to NRC (DCD), St. Lucie Units 1 and 2, Docket Nos. 50-335 and 50-389, *Summary Report of Individual Plant Examination for Severe Accident Vulnerabilities – Generic Letter 88-20;* December 9, 1993), the high reliability of the RCP seal design used at St. Lucie is evidenced by the fact that no failures leading to significantly large leakages have occurred at Combustion Engineering plants with Byron Jackson pumps throughout their operating history. No failure probability for RCP seals following a station blackout with loss of seal cooling was therefore assumed in the IPE analysis

since the RCPs would not be operating. The latest PSA update conservatively assumes a conditional seal LOCA probability of 8.91E-05/RCP, given loss of cooling and the pumps are secured, based on CEOG analyses.

An issue addressed in the St. Lucie IPE SER involved the IE frequency used for loss of a DC bus. The IE frequency used in the IPE was based on the generic bus failure probability over a year. As part of the PSA update, a fault tree was used to assess a new IE frequency for loss of a DC bus. The revised loss of DC bus IE frequency was incorporated in the previous PSA update and is, therefore, reflected in this EDG AOT evaluation. The new Loss of DC Bus IE frequency is 1.07E-03/yr compared to the IPE value of 3.94E-04/yr. It is judged that this re-assessment corrects the perceived deficiency identified in the SER and thus no further action is required.

For Unit 2, a plant design change was made that requires the SDC suction cross-connect valve to be locked open. The valve was normally closed during power operations, and this action was taken in response to concerns raised by GL 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power Operated Gate Valves". The modification also included a requirement to remove electrical power from each of the SDC suction isolation valve actuators by locking open their associated motor control circuit breakers. The intersystem-LOCA (ISLOCA) calculations were revised to include the plant design change. This resulted in an increase in the ISLOCA frequency. However, the plant design change prevents inadvertent opening of the SDC suction valves during power operations and improves the ability to initiate shutdown cooling operations for events involving loss of one train of electrical power. These factors were judged to offset the calculated risk increase such that the net change to ISLOCA is at least risk neutral.

The net effect of the modeling changes caused a slight increase in the calculated core damage frequency (CDF). However, when the data update was completed, including all other initiating events, the final result was a decrease in the calculated CDF for both units.

4.2.1.4.3 <u>PSA Reviews</u>. As discussed in the St. Lucie IPE submittal, three levels of review were used for the St. Lucie PSA. The first consisted of normal engineering quality assurance practices carried out by the organization performing the analysis. A qualified individual with knowledge of PSA methods and plant systems performed an independent review of the results for each task. This represents a detailed check of the input to the PSA model and provides a high degree of quality assurance.

The second level of review was performed by plant personnel not directly involved with the development of the PSA model. This review was performed by individuals from Operations, Technical Staff, Training, and the Independent Safety Engineering Group (ISEG) who reviewed the system description notebooks and accident sequence description. This provided diverse expertise with plant design and operations knowledge to review the system descriptions for accuracy.

The third level of review was performed by PSA experts from ERIN Engineering, FRH, Inc., NUS, and Baltimore Gas & Electric Company. This review provided broad insights on techniques and results based on experience from other plant PSAs. The review team concentrated on the overall PSA methodology, accident sequence analysis, system fault trees and draft quantification results. The intent was to provide early feedback to the St. Lucie staff concerning the adequacy and accuracy of the reviewed products.

The overall purpose of the three levels of review was to ensure the quality of the PSA project and to ensure that the project objectives were being met. The review team found that the project was successfully meeting those objectives with a sound methodology. Comments from the peer review included the following:

- The overall methodology reflects the current state of the art for PRAs and will meet the requirements of GL 88-20 (confirmed by the NRC St. Lucie IPE SER).
- The system description notebooks were very well organized and very complete.
- The event trees and success criteria used to support the systems analysis interface are consistent with those of other similar analyses.
- CST replenishment should be included for sequences where long-term cooling via AFW may be required (this was included for Unit1, not applicable for Unit 2).
- Units 1 and 2 data should be combined to formulate the plant-specific history (this was incorporated).

The methodologies used for the St. Lucie Level I and Level II analyses were similar to those used for FPL's Turkey Point PSA. The Turkey Point IPE submittal was thoroughly reviewed by the NRC staff and NRC contractors. The NRC review concluded that the process used to develop the Turkey Point PSA was acceptable in meeting the intent of GL 88-20.

For St. Lucie, another level of peer review is accomplished through the CEOG joint comparison process. The intent of this process is to provide an overall comparison of PSA results developed within the CE owners' group community to highlight differences and/or potential anomalies, and to provide confidence in the propriety of plant specific results and conclusions.

It should be noted here that outside peer review was not performed for the update described in part 4.2.1.2.4 of this attachment because the changes that were implemented are not considered to be extensive.

4.2.2 Tier 2, Avoidance of Risk-Significant Plant Configurations

Tier 2 is an identification of potentially high risk configurations that could exist if equipment in addition to that associated with the TS change is taken out of service concurrently, or other risk significant operational factors such as concurrent system or equipment testing are involved. The objective of Tier 2 is to ensure that appropriate restrictions are placed on dominant risk significant configurations that would be relevant to the proposed TS change.

The availability of the Startup Transformers, Blackout Crosstie, and Offsite Grid will affect the risk-significance of removing an EDG from service.

4.2.2.1 Startup transformers. If an offsite AC circuit (e.g., startup transformer) and an EDG are OOS at the same time, St. Lucie Technical Specification 3.8.1.1, Action "c" limits continued plant operation to 12 hours unless one of the AC sources can be restored to operable status. EDG and startup transformer PM activities would, therefore, not be scheduled at the same time. For CM activities, the affected components would be returned to service as soon as possible, and in accordance with the requirements of the action statement(s) of TS 3.8.1.1. Additional restrictions regarding removal of an EDG and startup transformer from service are, therefore, not required.

4.2.2.2 Blackout Crosstie. Relative to the status of the EDG, the availability of the SBO Crosstie could be affected by the following:

(1) An EDG on each unit is OOS at the same time, thereby creating a degraded condition for the unaffected unit during a station blackout event, i.e., failure of the unaffected unit's remaining EDG would impact use of the blackout crosstie.

Given one EDG OOS on each unit, there is only one EDG available on the unaffected unit to provide power via the blackout crosstie to the blacked-out unit. As shown in Table 13, the ICCDP for this case is <5E-07 except for Unit 1 CM, which is only slightly over 5E-07, i.e., 5.67E-07.

Table 13

ICCDP – AN EDG ON EACH UNIT OOS AT THE SAME TIME

Case	Unit 1	Unit 2
CM	5.67E-07	4.52E-07
PM	3.83E-07	2.68E-07

As shown in Table 14, the ICLERP is <5E-08 except for Unit 1 CM with a 0.1 containment failure probability (factor of 10 increase above the baseline value) which is 6.02E-08.

Table 14

ICLERP – AN EDG ON EACH UNIT OOS AT THE SAME TIME

	Using Early Containment Failure Probability = 0.01		Using Early Containment Failure Probability = 0.1	
Case	Unit 1	Unit 2	Unit 1	Unit 2
CM	9.21E-09	9.97E-09	6.02E-08	4.99E-08
PM	6.14E-09	7.67E-09	4.03E-08	3.15E-08

Based on the ICCDP and ICLERP results, it is judged that having an EDG OOS on both units at the same time is not risk-significant.

(2) An EDG and the SBO Crosstie OOS at the same time:

As shown in Table 15, the ICCDP for this case is >5E-07 for both CM and PM for both Units 1 and 2 (ranging from 1.34E-06 to 2.8E-06).

Table 15

ICCDP – AN EDG AND THE BLACKOUT CROSSTIE OOS AT THE SAME TIME

Case	Unit 1	Unit 2
CM	2.8E-06	2.22E-06
PM	1.91E-06	1.34E-06

Except for the Unit 2 CM case (5.06E-08) using the baseline 0.01 early containment failure probability, Table 16 shows the ICLERP <5E-08. The ICLERP is >5E-08 for both CM and PM for both units assuming a 0.1 early containment failure probability.

Table 16

ICLERP – AN EDG AND THE BLACKOUT CROSSTIE OOS AT THE SAME TIME

	Using Early Containment Failure Probability = 0.01		Using Early Containment Failure Probability = 0.1	
Case	Unit 1	Unit 2	Unit 1	Unit 2
CM	4.99E-08	5.06E-08	3.0E-07	2.46E-07
PM	3.34E-08	4.1E-08	2.04E-07	1.58E-07

The following Tier 2 restrictions are recommended regarding EDG and SBO Crosstie maintenance:

- If the blackout crosstie is unavailable, an EDG should be removed from service only for corrective maintenance (i.e., maintenance required to ensure or restore operability).

- If an EDG is unavailable, the blackout crosstie should be removed from service only for corrective maintenance (i.e., maintenance required to ensure or restore operability).

- If a condition is entered in which both an EDG and the blackout crosstie are unavailable at the same time, restore the EDG or blackout crosstie to service as soon as possible.

4.2.2.3 Grid Availability. Since the function of the EDGs is to provide power to safe shutdown loads following loss of offsite power, the availability of the EDGs when there is an increased risk of loss of offsite power should be ensured. Since high winds (hurricanes and tornadoes) could cause damage to the FPL grid and could result in a plant trip in conjunction with a loss of offsite power, the following Tier 2 restrictions are recommended:

- If a hurricane warning has been issued in an area which may impact the FPL grid (i.e., within the FPL service area), an EDG or the blackout crosstie should be removed from service only for corrective maintenance (i.e., maintenance required to ensure or restore operability).

- If an EDG or the blackout crosstie is unavailable when a hurricane warning in an area that may impact the FPL grid is issued, restore the unavailable component(s) to service as soon as possible

- If a tornado warning has been issued for an area which includes the St. Lucie Plant site, Midway substation, or the transmission lines between the Midway substation and the St. Lucie Plant switchyard, an EDG or the blackout crosstie should be removed from service only for corrective maintenance (i.e., maintenance required to ensure or restore operability).

- If an EDG or the blackout crosstie is unavailable when a tornado warning is issued for an area which includes the St. Lucie Plant site, Midway substation, or the transmission lines between the Midway substation and the St. Lucie Plant switchyard, restore the unavailable component(s) to service as soon as possible

In addition to the pre-determined Tier 2 restrictions, assessments performed in accordance with provisions of the proposed Configuration Risk Management Program (CRMP), discussed in section 4.2.3, will further ensure that any other potentially risk significant configurations are identified prior to removing an EDG from service for pre-planned maintenance. Similarly, implementation of the CRMP will ensure that the risk significance of unexpected configurations resulting from unplanned maintenance or conditions while an EDG is OOS is properly evaluated.

4.2.3 Tier 3, Configuration Risk Management

Tier 3 is the development of a proceduralized program, which ensures the risk impact of out-of-service equipment is appropriately evaluated prior to performing a maintenance activity. The program applies to technical specification structures, systems or components for which a risk-informed AOT has been granted. A viable program would be one that is able to uncover risk-significant plant equipment outage configurations in a timely manner during normal plant operation and is described in RG 1.177 as the CRMP. The need for this third tier stems from the difficulty of identifying all possible risk-significant configurations under Tier 2 that will be encountered over extended periods of plant operation.

The St. Lucie Technical Specifications do not presently contain any AOTs that require implementation of a CRMP. However, an engineering Reliability and Risk Assessment Group (RRAG), and use of a proceduralized risk management process is in place. This process is used for evaluating planned on-line maintenance and is also used to support compliance with the Maintenance Rule.

A CRMP based on the model program described in RG 1.177 is being developed and will be implemented to support the proposed and potential future risk-informed AOT extension(s). The primary tool for performing CRMP risk assessments for each St. Lucie unit will be the PSA-informed On-Line Risk Monitor (OLRM). The CRMP and its essential elements will be described in the St. Lucie Plant Administrative Procedure (ADM) that ensures compliance with the Maintenance Rule (currently identified as ADM-17.08, *Implementation of 10 CFR 50.65, the Maintenance Rule*). Except for the location of the program description, the proposed CRMP is consistent with the staff position of RG 1.177, Part C.2.3.7, which states in part, "Consistent with the fundamental principle that changes to TS result in small increases in the risk to public health and safety (Principle 4), certain configuration controls need to be utilized."

The CRMP proposed for the St. Lucie plant is described in FPL Letter L-99-079, J.A. Stall (FPL) to NRC (DCD), Dockets 50-335 and 50-389, Proposed License Amendments, *LPSI System Risk Informed AOT Extension*; June 1, 1999. Implementation methodology, control and use of the CRMP assessment tools, maintenance rule control as discussed in Part C.3.2 of RG 1.177, the OLRM, and requirements for RRAG specific evaluations associated with the CRMP are described therein. That submittal is currently under review by the NRC staff, and the CRMP as described therein is considered part of this submittal by reference.

5.0 Environmental Consideration

The proposed license amendments change requirements with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20. The proposed amendments involve no significant increase in the amounts and no significant change in the types of any effluents that may be released offsite, and no significant increase in individual or cumulative occupational radiation exposure. FPL has concluded that the proposed amendments involve no significant hazards consideration and meet the criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9) and that, pursuant to 10 CFR 51.22(b), an environmental impact statement or environmental assessment need not be prepared in connection with issuance of the amendments.

6.0 Conclusion

The risk contributions associated with extending the AOT for a single inoperable EDG from 72 hours to 14 days have been quantitatively evaluated using the current plant-specific Probabilistic Safety Assessment for St. Lucie Units 1 and 2. This updated and revised PSA analysis, in conjunction with other elements of CE NPSD-996 as supplemented, show that the small increase in the calculated "at power risk" can be offset by averting the risk associated with an unnecessary plant transition to a shutdown mode, and/or reduced risk during shutdown operations that can result from improved flexibility in scheduling and performing surveillance and maintenance activities.

FPL has determined that defense-in-depth philosophy is maintained with the proposed AOT, and has evaluated the risk-impact from potential EDG unavailability using the three-tiered approach for performing risk assessments that is identified in regulatory guidelines. The calculated increases in the average CDF and LERF are "very small" as defined in RG 1.174, and calculations performed for ICCDP and ICLERP demonstrate these values to be "small" as defined in RG 1.177.

The integrated assessment reported in CE NPSD-996, as supplemented by the associated 1997 RAI response and this submittal, generally conforms to guidance provided in NUREG/CR-6141, *Handbook of Methods for Risk Based Analyses of Technical Specifications,* December 1994. Relative to the average core damage frequency calculated for the appropriate severe accidents, NUREG/CR-6141 states, "A risk-based AOT assures that the single event and yearly AOT risk contributions are acceptable." FPL believes the proposed 14-day AOT for the EDG qualifies as a beneficial risk-based AOT, and that the proposed amendments are acceptable.

Unit 1 Conditional CDF w/1 EDG Not Out for T/M (Baseline)

ONETOP = 1.39E-05

#	Inputs	Description	Event Prob	Cutset Probability
1	%ZZS1U1	SMALL-SMALL LOCA	3.01E-03	1.64E-06
	CMM1AVCCCF	N-HEADER AIR OPERATED ISOLATION VALVES FTC DUE TO COMMON CAUSES	5.44E-04	
2	%ZZS1U1	SMALL-SMALL LOCA	3.01E-03	1.26E-06
	GMM1MRMOV	MINIMUM RECIRC LINE MOTOR VALVES TRANSFER CLOSED	4.19E-04	
3	%ZZS1U1	SMALL-SMALL LOCA	3.01E-03	8.87E-07
	GMM1FTRCFI	COMMON CAUSE FAILURE OF HPSI PUMPS TO RUN DURING INJECTION	2.95E-04	
4	%ZZT1U1	REACTOR TRIPS	1.90E+00	8.38E-07
	NMM1CEDM	MECHANICAL FAULT PREVENTING ROD INSERTION	2.10E-06	
	ZZMTCUNF1	MODERATOR TEMPERATURE COEFFICIENT UNFAVORABLE (UNIT 1)	2.10E-01	
5	%ZZS1U1	SMALL-SMALL LOCA	3.01E-03	5.78E-07
	QMM1MVCCCF	ICW MOTOR OPERATED VALVES FAIL TO CLOSE DUE TO COMMON CAUSE FAILURES	1.92E-04	
6	%ZZS1U1	SMALL-SMALL LOCA	3.01E-03	4.17E-07
	GMM1MPACCF	COMMON CAUSE FAILURE OF HPSI PUMPS TO START	1.38E-04	
7	%ZZCCWU1	LOSS OF CCW	9.41E-04	2.82E-07
	RTOP1S1RCP	OPERATOR FAILS TO SECURE RCPS FOLLOWING LOSS OF SEAL COOLING	3.00E-04	
8	%ZZS1U1	SMALL-SMALL LOCA	3.01E-03	2.28E-07
	GMM1HCVCCF	COMMON CAUSE FAILURE OF HPSI INJECTION VALVES TO OPEN	7.58E-05	
9	%ZZT3AU1	LOSS OF MAIN FEEDWATER BUT RECOVERABLE	4.34E-01	1.91E-07
	NMM1CEDM	MECHANICAL FAULT PREVENTING ROD INSERTION	2.10E-06	
	ZZMTCUNF1	MODERATOR TEMPERATURE COEFFICIENT UNFAVORABLE (UNIT 1)	2.10E-01	
10	%ZZT1U1	REACTOR TRIPS	1.90E+00	1.38E-07
	NMM1CEDM	MECHANICAL FAULT PREVENTING ROD INSERTION	2.10E-06	
	ZZ1ABKSHUT	'A' BLK VLV CLOSE W/POWER	4.36E-02	
	ZZMTCNUNF1	MTC NOT UNFAVORABLE (UNIT 1)	7.90E-01	

Unit 1 Conditional CDF w/1 EDG Unavailable for CM Case

ONETOP = 2.14E-05

#	Inputs	Description	Event Prob	Cutset Probability
1	%ZZS1U1	SMALL-SMALL LOCA	3.01E-03	1.64E-06
	CMM1AVCCCF	N-HEADER AIR OPERATED ISOLATION VALVES FTC DUE TO COMMON CAUSES	5.44E-04	
2	%ZZLOG	LOSS OF GRID	1.00E-01	1.64E-06
	EMM1CCFDGS	COMMON CAUSE FAILURE OF EDG'S 1A AND 1B TO START	5.00E-02	
	REPS1CASE5	OFF-SITE POWER RECOVERY CASE 5: CCF OF DIESELS TO START	4.16E-02	
	ZZXCROSST	BLACKOUT CROSSTIE OOS	1.00E-01	
	R#CAFWMAN	OPERATOR FAILS TO MANUALLY START C AFW Pp PER EOP-99, APP. G	7.88E-02	
3	%ZZS1U1	SMALL-SMALL LOCA	3.01E-03	1.26E-06
	GMM1MRMOV	MINIMUM RECIRC LINE MOTOR VALVES TRANSFER CLOSED	4.19E-04	
4	%ZZS1U1	SMALL-SMALL LOCA	3.01E-03	8.87E-07
	GMM1FTRCFI	COMMON CAUSE FAILURE OF HPSI PUMPS TO RUN DURING INJECTION	2.95E-04	
	%ZZT1U1	REACTOR TRIPS	1.90E+00	8.38E-07
	NMM1CEDM	MECHANICAL FAULT PREVENTING ROD INSERTION	2.10E-06	
	ZZMTCUNF1	MODERATOR TEMPERATURE COEFFICIENT UNFAVORABLE (UNIT 1)	2.10E-01	
6	%ZZLOG	LOSS OF GRID	1.00E-01	5.80E-07
	EMM1ADGFTS	EDG 1A FAILS TO START	1.77E-02	
	ETM11BEDG	1B EDG IN TEST OR MAINTENANCE	1.00E+00	
	REPS1CASE1	OFF-SITE POWER RECOVERY CASE 1: BOTH DIESELS FAIL TO START	4.16E-02	
	ZZXCROSST	BLACKOUT CROSSTIE OOS	1.00E-01	
	R#CAFWMAN	OPERATOR FAILS TO MANUALLY START C AFW Pp PER EOP-99, APP. G	7.88E-02	
7	%ZZS1U1	SMALL-SMALL LOCA	3.01E-03	5.78E-07
	QMM1MVCCCF	ICW MOTOR OPERATED VALVES FAIL TO CLOSE DUE TO COMMON CAUSE FAILURES	1.92E-04	
8	%ZZLOG	LOSS OF GRID	1.00E-01	5.20E-07
	EMM11AEDG	EDG 1A FAILS TO RUN (24 HOUR EXPOSURE)	3.80E-02	
	ETM11BEDG	1B EDG IN TEST OR MAINTENANCE	1.00E+00	
	REPS1CASE3	OFF-SITE POWER RECOVERY CASE 3: 1 DIESEL FTS (OR T&M) OTHER DG FTR	1.74E-02	
	ZZXCROSST	BLACKOUT CROSSTIE OOS	1.00E-01	
	R#CAFWMAN	OPERATOR FAILS TO MANUALLY START C AFW Pp PER EOP-99, APP. G	7.88E-02	

#	Inputs	Description	Event Prob	Cutset Probability
9	%ZZLOG	LOSS OF GRID	1.00E-01	4.30E-07
	EMM1CCFDGR	COMMON CAUSE FAILURE OF EDG'S 1A AND 1B TO RUN FOR 24 HOURS	5.00E-02	
	REPS1CASE6	OFF-SITE POWER NON-RECOVERY CASE 6:CCF OF DIESELS TO RUN	1.09E-02	
	ZZXCROSST	BLACKOUT CROSSTIE OOS	1.00E-01	
	R#CAFWMAN	OPERATOR FAILS TO MANUALLY START C AFW Pp PER EOP-99, APP. G	7.88E-02	
10	%ZZS1U1	SMALL-SMALL LOCA	3.01E-03	4.17E-07
	GMM1MPACCF	COMMON CAUSE FAILURE OF HPSI PUMPS TO START	1.38E-04	

Unit 1 Conditional CDF w/1 EDG Unavailable for PM Case

ONETOP = 1.89E-05

#	Inputs	Description	Event Prob	Cutset Probability
1	%ZZS1U1	SMALL-SMALL LOCA	3.01E-03	1.64E-06
	CMM1AVCCCF	N-HEADER AIR OPERATED ISOLATION VALVES FTC DUE TO COMMON CAUSES	5.44E-04	
2	%ZZS1U1	SMALL-SMALL LOCA	3.01E-03	1.26E-06
	GMM1MRMOV	MINIMUM RECIRC LINE MOTOR VALVES TRANSFER CLOSED	4.19E-04	
3	%ZZS1U1	SMALL-SMALL LOCA	3.01E-03	8.87E-07
	GMM1FTRCFI	COMMON CAUSE FAILURE OF HPSI PUMPS TO RUN DURING INJECTION	2.95E-04	
4	%ZZT1U1	REACTOR TRIPS	1.90E+00	8.38E-07
	NMM1CEDM	MECHANICAL FAULT PREVENTING ROD INSERTION	2.10E-06	
	ZZMTCUNF1	MODERATOR TEMPERATURE COEFFICIENT UNFAVORABLE (UNIT 1)	2.10E-01	
5	%ZZLOG	LOSS OF GRID	1.00E-01	5.80E-07
	EMM1ADGFTS	EDG 1A FAILS TO START	1.77E-02	
	ETM11BEDG	1B EDG IN TEST OR MAINTENANCE	1.00E+00	
	REPS1CASE1	OFF-SITE POWER RECOVERY CASE 1: BOTH DIESELS FAIL TO START	4.16E-02	
	ZZXCROSST	BLACKOUT CROSSTIE OOS	1.00E-01	
	R#CAFWMAN	OPERATOR FAILS TO MANUALLY START C AFW Pp PER EOP-99, APP. G	7.88E-02	
6	%ZZS1U1	SMALL-SMALL LOCA	3.01E-03	5.78E-07
	QMM1MVCCCF	ICW MOTOR OPERATED VALVES FAIL TO CLOSE DUE TO COMMON CAUSE FAILURES	1.92E-04	
7	%ZZLOG	LOSS OF GRID	1.00E-01	5.20E-07
	EMM11AEDG	EDG 1A FAILS TO RUN (24 HOUR EXPOSURE)	3.80E-02	
	ETM11BEDG	1B EDG IN TEST OR MAINTENANCE	1.00E+00	
	REPS1CASE3	OFF-SITE POWER RECOVERY CASE 3: 1 DIESEL FTS (OR T&M) OTHER DG FTR	1.74E-02	
	ZZXCROSST	BLACKOUT CROSSTIE OOS	1.00E-01	
	R#CAFWMAN	OPERATOR FAILS TO MANUALLY START C AFW Pp PER EOP-99, APP. G	7.88E-02	
8	%ZZS1U1	SMALL-SMALL LOCA	3.01E-03	4.17E-07
	GMM1MPACCF	COMMON CAUSE FAILURE OF HPSI PUMPS TO START	1.38E-04	
9	%ZZCCWU1	LOSS OF CCW	9.41E-04	2.82E-07
	RTOP1S1RCP	OPERATOR FAILS TO SECURE RCPS FOLLOWING LOSS OF SEAL COOLING	3.00E-04	
10	%ZZS1U1	SMALL-SMALL LOCA	3.01E-03	2.28E-07
	GMM1HCVCCF	COMMON CAUSE FAILURE OF HPSI INJECTION VALVES TO OPEN	7.58E-05	

Unit 1 Proposed Average CDF Using EDG Set at Proposed Downtime Value

ONETOP = 1.41E-05

#	Inputs	Description	Event Prob	Cutset Probability
1	%ZZS1U1	SMALL-SMALL LOCA	3.01E-03	1.64E-06
	CMM1AVCCCF	N-HEADER AIR OPERATED ISOLATION VALVES FTC DUE TO COMMON CAUSES	5.44E-04	
2	%ZZS1U1	SMALL-SMALL LOCA	3.01E-03	1.26E-06
	GMM1MRMOV	MINIMUM RECIRC LINE MOTOR VALVES TRANSFER CLOSED	4.19E-04	
3	%ZZS1U1	SMALL-SMALL LOCA	3.01E-03	8.87E-07
	GMM1FTRCFI	COMMON CAUSE FAILURE OF HPSI PUMPS TO RUN DURING INJECTION	2.95E-04	
4	%ZZT1U1	REACTOR TRIPS	1.90E+00	8.38E-07
	NMM1CEDM	MECHANICAL FAULT PREVENTING ROD INSERTION	2.10E-06	
	ZZMTCUNF1	MODERATOR TEMPERATURE COEFFICIENT UNFAVORABLE (UNIT 1)	2.10E-01	
5	%ZZS1U1	SMALL-SMALL LOCA	3.01E-03	5.78E-07
	QMM1MVCCCF	ICW MOTOR OPERATED VALVES FAIL TO CLOSE DUE TO COMMON CAUSE FAILURES	1.92E-04	
6	%ZZS1U1	SMALL-SMALL LOCA	3.01E-03	4.17E-07
	GMM1MPACCF	COMMON CAUSE FAILURE OF HPSI PUMPS TO START	1.38E-04	
7	%ZZCCWU1	LOSS OF CCW	9.41E-04	2.82E-07
	RTOP1S1RCP	OPERATOR FAILS TO SECURE RCPS FOLLOWING LOSS OF SEAL COOLING	3.00E-04	
8	%ZZS1U1	SMALL-SMALL LOCA	3.01E-03	2.28E-07
	GMM1HCVCCF	COMMON CAUSE FAILURE OF HPSI INJECTION VALVES TO OPEN	7.58E-05	
9	%ZZT3AU1	LOSS OF MAIN FEEDWATER BUT RECOVERABLE	4.34E-01	1.91E-07
	NMM1CEDM	MECHANICAL FAULT PREVENTING ROD INSERTION	2.10E-06	
	ZZMTCUNF1	MODERATOR TEMPERATURE COEFFICIENT UNFAVORABLE (UNIT 1)	2.10E-01	
10	%ZZT1U1	REACTOR TRIPS	1.90E+00	1.38E-07
	NMM1CEDM	MECHANICAL FAULT PREVENTING ROD INSERTION	2.10E-06	
	ZZ1ABKSHUT	'A' BLK VLV CLOSE W/POWER	4.36E-02	
	ZZMTCNUNF1	MTC NOT UNFAVORABLE (UNIT 1)	7.90E-01	

Unit 2 Conditional CDF w/1 EDG Not Out for T/M (Baseline)

ONETOP = 1.23E-05

#	Inputs	Description	Event Prob	Cutset Probability
1	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03	1.64E-06
	CMM2AVCCCF	N-HEADER AIR OPERATED ISOLATION VALVES FAIL TO CLOSE DUE TO COMMON CAUSES	5.44E-04	
2	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03	9.90E-07
	GMM2SMVCCF	COMMON CAUSE FAILURE OF SUMP OUTLET MOTOR VALVES TO OPEN	3.29E-04	
3	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03	8.87E-07
	GMM2FTRCFI	COMMON CAUSE FAILURE OF HPSI PUMPS TO RUN DURING INJECTION	2.95E-04	
4	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03	5.78E-07
	QMM2MVCCCF	ICW MOTOR OPERATED VALVES FAIL TO CLOSE DUE TO COMMON CAUSE FAILURES	1.92E-04	
5	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03	4.17E-07
	GMM2MPACCF	COMMON CAUSE FAILURE OF HPSI PUMPS TO START	1.38E-04	
6	%ZZCCWU2	LOSS OF CCW	9.41E-04	2.82E-07
	RTOP2S1RCP	OPERATOR FAILS TO SECURE RCPS FOLLOWING LOSS OF SEAL COOLING	3.00E-04	
7	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03	2.28E-07
	GMM2HCVCCF	COMMON CAUSE FAILURE OF HPSI INJECTION VALVES TO OPEN	7.58E-05	
8	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03	1.56E-07
	GMVR23523	MOTOR-OPERATED VALVE V3523 TRANSFERS OPEN DURING STANDBY	8.81E-03	
	GMVR23551	MOTOR-OPERATED VALVE V3551 TRANSFERS OPEN	5.88E-03	
9	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03	1.56E-07
	GMVR23540	MOTOR-OPERATED VALVE 3540 TRANSFERS OPEN DURING STANDBY	8.81E-03	
	GMVR23550	MOTOR-OPERATED VALVE V3550 TRANSFERS OPEN	5.88E-03	
10	%ZZDC2B	LOSS OF DC BUS 2B FOR UNIT 2	1.07E-03	1.03E-07
	NMM2TCBCCF	COMMON CAUSE FAILURE OF THE TRIP CIRCUIT BREAKERS	9.60E-05	

Unit 2 Conditional CDF w/1 EDG Unavailable for CM Case

ONETOP = 1.83E-05

#	Inputs	Description	Event Prob	Cutset Probability
1	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03	1.64E-06
	CMM2AVCCCF	N-HEADER AIR OPERATED ISOLATION VALVES FAIL TO CLOSE DUE TO COMMON CAUSES	5.44E-04	
2	%ZZLOG	LOSS OF GRID	1.00E-01	1.64E-06
	EMM2CCFDGS	COMMON CAUSE FAILURE OF EDG'S 2A AND 2B TO START	5.00E-02	
	REPS2CASE5	OFF-SITE POWER RECOVERY CASE 5: CCF OF DIESELS TO START	4.16E-02	
	ZZXCROSST	FAIL TO USE B/O CROSSTIE FROM UNIT 1 (W/EQUIP, OP, TIE BKR FAILURES)	1.00E-01	
	R#CAFWMAN	OPERATOR FAILS TO MANUALLY START C AFW Pp PER EOP-99, APP. G	7.88E-02	
3	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03	9.90E-07
	GMM2SMVCCF	COMMON CAUSE FAILURE OF SUMP OUTLET MOTOR VALVES TO OPEN	3.29E-04	
4	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03	8.87E-07
	GMM2FTRCFI	COMMON CAUSE FAILURE OF HPSI PUMPS TO RUN DURING INJECTION	2.95E-04	
5	%ZZLOG	LOSS OF GRID	1.00E-01	5.80E-07
	EMM2ADGFTS	EDG 2A FAILS TO START	1.77E-02	
	ETM22BEDG	2B EDG OUT FOR TEST OR MAINTENANCE	1.00E+00	
	REPS2CASE1	OFF-SITE POWER RECOVERY CASE 1: BOTH DIESELS FAIL TO START	4.16E-02	
	ZZXCROSST	FAIL TO USE B/O CROSSTIE FROM UNIT 1 (W/EQUIP, OP, TIE BKR FAILURES)	1.00E-01	
	R#CAFWMAN	OPERATOR FAILS TO MANUALLY START C AFW Pp PER EOP-99, APP. G	7.88E-02	
6	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03	5.78E-07
	QMM2MVCCCF	ICW MOTOR OPERATED VALVES FAIL TO CLOSE DUE TO COMMON CAUSE FAILURES	1.92E-04	
7	%ZZLOG	LOSS OF GRID	1.00E-01	5.20E-07
	EMM22AEDG	EDG 2A FAILS TO RUN	3.80E-02	
	ETM22BEDG	2B EDG OUT FOR TEST OR MAINTENANCE	1.00E+00	
	REPS2CASE3	OFF-SITE POWER RECOVERY CASE 3: 1 EDG FTR/1 EDG FAILS TO START	1.74E-02	
	ZZXCROSST	FAIL TO USE B/O CROSSTIE FROM UNIT 1 (W/EQUIP, OP, TIE BKR FAILURES)	1.00E-01	
	R#CAFWMAN	OPERATOR FAILS TO MANUALLY START C AFW Pp PER EOP-99, APP. G	7.88E-02	

#	Inputs	Description	Event Prob	Cutset Probability
8	%ZZLOG	LOSS OF GRID	1.00E-01	4.30E-07
	EMM2CCFDGR	COMMON CAUSE FAILURE OF EDG'S 2A AND 2B TO RUN	5.00E-02	
	REPS2CASE6	OFF-SITE POWER RECOVERY CASE 6: CCF OF DIESELS TO RUN	1.09E-02	
	ZZXCROSST	FAIL TO USE B/O CROSSTIE FROM UNIT 1 (W/EQUIP, OP, TIE BKR FAILURES)	1.00E-01	
	R#CAFWMAN	OPERATOR FAILS TO MANUALLY START C AFW Pp PER EOP-99, APP. G	7.88E-02	
9	%ZZLOG	LOSS OF GRID	1.00E-01	4.27E-07
	EMM2AFLVLV	INDEPENDENT FAILURES OF 2A EDG DAY TANK FUEL OIL FILL VALVES	6.68E-02	
	ETM22BEDG	2B EDG OUT FOR TEST OR MAINTENANCE	1.00E+00	
	REPS2CASE3	OFF-SITE POWER RECOVERY CASE 3: 1 EDG FTR/1 EDG FAILS TO START	1.74E-02	
	ZZXCROSST	FAIL TO USE B/O CROSSTIE FROM UNIT 1 (W/EQUIP, OP, TIE BKR FAILURES)	1.00E-01	
	R#DGFO	OPERATOR FAILS TO RECOVER EDG BY OPENING DG FILL VALVE BYPASS	3.68E-02	
10	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03	4.17E-07
	GMM2MPACCF	COMMON CAUSE FAILURE OF HPSI PUMPS TO START	1.38E-04	

Unit 2 Conditional CDF w/1 EDG Unavailable for PM Case

ONETOP = 1.58E-05

#	Inputs	Description	Event Prob	Cutset Probability
1	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03	1.64E-06
	CMM2AVCCCF	N-HEADER AIR OPERATED ISOLATION VALVES FAIL TO CLOSE DUE TO COMMON CAUSES	5.44E-04	
2	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03	9.90E-07
	GMM2SMVCCF	COMMON CAUSE FAILURE OF SUMP OUTLET MOTOR VALVES TO OPEN	3.29E-04	
3	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03	8.87E-07
	GMM2FTRCFI	COMMON CAUSE FAILURE OF HPSI PUMPS TO RUN DURING INJECTION	2.95E-04	
4	%ZZLOG	LOSS OF GRID	1.00E-01	5.80E-07
	EMM2ADGFTS	EDG 2A FAILS TO START	1.77E-02	
	ETM22BEDG	2B EDG OUT FOR TEST OR MAINTENANCE	1.00E+00	
	REPS2CASE1	OFF-SITE POWER RECOVERY CASE 1: BOTH DIESELS FAIL TO START	4.16E-02	
	ZZXCROSST	FAIL TO USE B/O CROSSTIE FROM UNIT 1 (W/EQUIP, OP, TIE BKR FAILURES)	1.00E-01	
	R#CAFWMAN	OPERATOR FAILS TO MANUALLY START C AFW Pp PER EOP-99, APP. G	7.88E-02	
5	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03	5.78E-07
	QMM2MVCCCF	ICW MOTOR OPERATED VALVES FAIL TO CLOSE DUE TO COMMON CAUSE FAILURES	1.92E-04	
6	%ZZLOG	LOSS OF GRID	1.00E-01	5.20E-07
	EMM22AEDG	EDG 2A FAILS TO RUN	3.80E-02	
	ETM22BEDG	2B EDG OUT FOR TEST OR MAINTENANCE	1.00E+00	
	REPS2CASE3	OFF-SITE POWER RECOVERY CASE 3: 1 EDG FTR/1 EDG FAILS TO START	1.74E-02	
	ZZXCROSST	FAIL TO USE B/O CROSSTIE FROM UNIT 1 (W/EQUIP, OP, TIE BKR FAILURES)	1.00E-01	
	R#CAFWMAN	OPERATOR FAILS TO MANUALLY START C AFW Pp PER EOP-99, APP. G	7.88E-02	
7	%ZZLOG	LOSS OF GRID	1.00E-01	4.27E-07
	EMM2AFLVLV	INDEPENDENT FAILURES OF 2A EDG DAY TANK FUEL OIL FILL VALVES	6.68E-02	
	ETM22BEDG	2B EDG OUT FOR TEST OR MAINTENANCE	1.00E+00	
	REPS2CASE3	OFF-SITE POWER RECOVERY CASE 3: 1 EDG FTR/1 EDG FAILS TO START	1.74E-02	
	ZZXCROSST	FAIL TO USE B/O CROSSTIE FROM UNIT 1 (W/EQUIP, OP, TIE BKR FAILURES)	1.00E-01	
	R#DGFO	OPERATOR FAILS TO RECOVER EDG BY OPENING DG FILL VALVE BYPASS	3.68E-02	

#	Inputs	Description	Event Prob	Cutset Probability
8	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03	4.17E-07
	GMM2MPACCF	COMMON CAUSE FAILURE OF HPSI PUMPS TO START	1.38E-04	
9	%ZZCCWU2	LOSS OF CCW	9.41E-04	2.82E-07
	RTOP2S1RCP	OPERATOR FAILS TO SECURE RCPS FOLLOWING LOSS OF SEAL COOLING	3.00E-04	
10	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03	2.28E-07
	GMM2HCVCCF	COMMON CAUSE FAILURE OF HPSI INJECTION VALVES TO OPEN	7.58E-05	

Unit 2 Proposed Average CDF Using EDG T/M Set at Proposed Downtime Value

ONETOP = 1.24E-05

#	Inputs	Description	Event Prob	Cutset Probability
1	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03	1.64E-06
	CMM2AVCCCF	N-HEADER AIR OPERATED ISOLATION VALVES FAIL TO CLOSE DUE TO COMMON CAUSES	5.44E-04	
2	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03	9.90E-07
	GMM2SMVCCF	COMMON CAUSE FAILURE OF SUMP OUTLET MOTOR VALVES TO OPEN	3.29E-04	
3	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03	8.87E-07
	GMM2FTRCFI	COMMON CAUSE FAILURE OF HPSI PUMPS TO RUN DURING INJECTION	2.95E-04	
4	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03	5.78E-07
	QMM2MVCCCF	ICW MOTOR OPERATED VALVES FAIL TO CLOSE DUE TO COMMON CAUSE FAILURES	1.92E-04	
5	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03	4.17E-07
	GMM2MPACCF	COMMON CAUSE FAILURE OF HPSI PUMPS TO START	1.38E-04	
6	%ZZCCWU2	LOSS OF CCW	9.41E-04	2.82E-07
	RTOP2S1RCP	OPERATOR FAILS TO SECURE RCPS FOLLOWING LOSS OF SEAL COOLING	3.00E-04	
7	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03	2.28E-07
	GMM2HCVCCF	COMMON CAUSE FAILURE OF HPSI INJECTION VALVES TO OPEN	7.58E-05	
8	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03	1.56E-07
	GMVR23523	MOTOR-OPERATED VALVE V3523 TRANSFERS OPEN DURING STANDBY	8.81E-03	
	GMVR23551	MOTOR-OPERATED VALVE V3551 TRANSFERS OPEN	5.88E-03	
9	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03	1.56E-07
	GMVR23540	MOTOR-OPERATED VALVE 3540 TRANSFERS OPEN DURING STANDBY	8.81E-03	
	GMVR23550	MOTOR-OPERATED VALVE V3550 TRANSFERS OPEN	5.88E-03	
10	%ZZDC2B	LOSS OF DC BUS 2B FOR UNIT 2	1.07E-03	1.03E-07
	NMM2TCBCCF	COMMON CAUSE FAILURE OF THE TRIP CIRCUIT BREAKERS	9.60E-05	

ATTACHMENT 2 to L-99-228

DETERMINATION OF NO SIGNIFICANT HAZARDS CONSIDERATION

DETERMINATION OF NO SIGNIFICANT HAZARDS CONSIDERATION

Description of amendment request: The amendments proposed for St. Lucie Units 1 and 2 will revise the current 72-hour action completion time/allowed outage time (AOT) specified in Technical Specification (TS) 3.8.1.1, Action "b," to allow 14 days to restore an inoperable emergency diesel generator set to operable status. The proposed AOT is based on an integrated review and assessment of plant operations, deterministic design basis factors, and an evaluation of overall plant risk using probabilistic safety assessment techniques.

Pursuant to 10CFR50.92, a determination may be made that a proposed license amendment involves no significant hazards consideration if operation of the facility in accordance with the proposed amendment would not: (1) involve a significant increase in the probability or consequences of an accident previously evaluated; or (2) create the possibility of a new or different kind of accident from any accident previously evaluated; or (3) involve a significant reduction in a margin of safety. Each standard is discussed as follows:

(1) Operation of the facility in accordance with the proposed amendment would not involve a significant increase in the probability or consequences of an accident previously evaluated.

The proposed amendments for St. Lucie Unit 1 and Unit 2 will extend the action completion/allowed outage time (AOT) for a single inoperable Emergency Diesel Generator (EDG) from 72 hours to 14 days. The EDGs are designed as backup AC power sources for essential safety systems in the event of a loss of offsite power. As such, the EDGs are not accident initiators, and an extended AOT to restore operability of an inoperable diesel generator would not significantly increase the probability of occurrence of accidents previously analyzed.

The proposed technical specification revisions involve the AOT for a single inoperable EDG, and do not change the conditions, operating configuration, or minimum amount of operating equipment assumed in the plant safety analyses for accident mitigation. Plant defense-in-depth capabilities will be maintained with the proposed AOT, and the design basis for electric power systems will continue to conform with 10 CFR 50, Appendix A, General Design Criterion 17. In addition, a Probability Safety Assessment (PSA) was performed to quantitatively assess the risk-impact of the proposed amendment for each unit. The impact on the early radiological release probability for design basis events was also evaluated and it is concluded that the risk contribution from this proposed AOT is small and consistent with regulatory risk-assessment acceptance guidelines.

Therefore, operation of either facility in accordance with its proposed amendment would not involve a significant increase in the probability or consequences of an accident previously evaluated.

(2) Operation of the facility in accordance with the proposed amendment would not create the possibility of a new or different kind of accident from any accident previously evaluated.

The proposed amendments will not change the physical plant or the modes of operation defined in either facility license. The changes do not involve the addition of new equipment or the modification of existing equipment, nor do they alter the design of St. Lucie plant systems. Therefore, operation of either facility in accordance with its proposed amendment would not create the possibility of a new or different kind of accident from any accident previously evaluated.

(3) Operation of the facility in accordance with the proposed amendment would not involve a significant reduction in a margin of safety.

The proposed amendments are designed to improve EDG reliability by providing flexibility in the scheduling and performance of preventive and corrective maintenance activities. The surveillance intervals or the operability requirements are not changed by the proposal; only the AOT for a single inoperable EDG will be extended. The proposed changes do not alter the basis for any technical specification that is related to the establishment of, or the maintenance of, a nuclear safety margin, and design defense-in-depth capabilities are maintained. An integrated assessment of the risk impact of extending the AOT for a single inoperable EDG has determined that the risk contribution is small and is within regulatory guidelines for an acceptable TS change. Therefore, operation of either facility in accordance with its proposed amendment would not involve a significant reduction in a margin of safety.

Based on the discussion presented above and on the supporting Evaluation of Proposed TS Changes, FPL has concluded that the proposed license amendments involve no significant hazards consideration.

ATTACHMENT 3 to L-99-228

ST. LUCIE UNIT 1 MARKED-UP TECHNICAL SPECIFICATION PAGES

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INSERT - A

3/4.8 ELECTRICAL POWER SYSTEMS

3/4.8.1 A.C. SOURCES

OPERATING

LIMITING CONDITION FOR OPERATION

3.8.1.1 As a minimum, the following A.C. electrical power sources shall be OPERABLE:

a. Two physically independent circuits between the offsite transmission network and the onsite Class 1E distribution system, and

b. Two separate and independent diesel generator sets each with:

1. Engine-mounted fuel tanks containing a minimum of 152 gallons of fuel,

2. A separate fuel storage system containing a minimum of 16,450 gallons of fuel, and

3. A separate fuel transfer pump.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

a. With one offsite circuit of 3.8.1.1.a inoperable, except as provided in Action f. below, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. Restore the offsite circuit to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and COLD SHUTDOWN within the following 30 hours.

b. With one diesel generator of 3.8.1.1.b inoperable, demonstrate the OPERABILITY of the A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter; and if the EDG became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned preventative maintenance or testing, demonstrate the OPERABILITY of the remaining OPERABLE EDG by performing Surveillance Requirement 4.8.1.1.2.a.4 within 8 hours, unless it can be confirmed that the cause of the inoperable EDG does not exist on the remaining EDG*; restore the diesel generator to OPERABLE status within ~~72 hours~~ 14 days or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours. Additionally, verify within 2 hours or be in HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours that:

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* If the absence of any common-cause failure cannot be confirmed, this test shall be completed regardless of when the inoperable EDG is restored to OPERABILITY.

BASES

The OPERABILITY of the A.C. and D.C. power sources and associated distribution systems during operation ensures that sufficient power will be available to supply the safety related equipment required for 1) the safe shutdown of the facility and 2) the mitigation and control of accident conditions within the facility. The minimum specified independent and redundant A.C. and D.C. power sources and distribution systems satisfy the requirements of General Design Criteria 17 of Appendix "A" to 10 CFR 50.

The ACTION requirements specified for the levels of degradation of the power sources provide restriction upon continued facility operation commensurate with the level of degradation. The OPERABILITY of the power sources are consistent with the initial condition assumptions of the accident analyses and are based upon maintaining at least one of each of the onsite A.C. and D.C. power sources and associated distribution systems OPERABLE during accident conditions coincident with an assumed loss of offsite power and single failure of the other onsite A.C. source. When one diesel generator is inoperable, there is an additional ACTION requirement to verify that all required systems, subsystems, trains, components and devices that depend on the remaining OPERABLE diesel generator as a source of emergency power, are also OPERABLE, and that the steam-driven auxiliary feedwater pump is OPERABLE. This requirement is intended to provide assurance that a loss of offsite power event will not result in a complete loss of safety function of critical systems during the period one of the diesel generators is inoperable. The term verify as used in this context means to administratively check by examining logs or other information to determine if certain components are out-of-service for maintenance or other reasons. It does not mean to perform the surveillance requirements needed to demonstrate the OPERABILITY of the component.

INSERT A

All EDG inoperabilities must be investigated for common-cause failures regardless of how long the EDG inoperability persists. When one diesel generator is inoperable, required ACTIONS 3.8.1.1.b and 3.8.1.1.c provide an allowance to avoid unnecessary testing of EDGs. If it can be determined that the cause of the inoperable EDG does not exist on the remaining OPERABLE EDG, then SR 4.8.1.1.2.a.4 does not have to be performed. Eight (8) hours is reasonable to confirm that the OPERABLE EDG is not affected by the same problem as the inoperable EDG. If it cannot otherwise be determined that the cause of the initial inoperable EDG does not exist on the remaining EDG, then satisfactory performance of SR 4.8.1.1.2.a.4 suffices to provide assurance of continued OPERABILITY of that EDG. If the cause of the initial inoperability exists on the remaining OPERABLE EDG, that EDG would also be declared inoperable upon discovery, and ACTION 3.8.1.1.e would be entered. Once the failure is repaired (on either EDG), the common-cause failure no longer exists.

Ambient conditions are the normal standby conditions for the diesel engines. Any normally running warmup systems should be in service and operating, and manufacturer's recommendations for engine oil and water temperatures and other parameters should be followed.

The OPERABILITY of the minimum specified A.C. and D.C. power sources and associated distribution systems during shutdown and refueling ensures that 1) the facility can be maintained in the shutdown or refueling condition for extended time periods and 2) sufficient instrumentation and control capability is available for monitoring and maintaining the facility status.

INSERT – A

TS 3.8.1.1, ACTION "b" provides an allowed outage/action completion time (AOT) of up to 14 days to restore a single inoperable diesel generator to operable status. This AOT is based on the findings of a deterministic and probabilistic safety analysis and is referred to as a "risk-informed" AOT. Entry into this action requires that a risk assessment be performed in accordance with the Configuration Risk Management Program (CRMP), which is described in the Administrative Procedure that implements the Maintenance Rule pursuant to 10 CFR 50.65.

St. Lucie Unit 1 and Unit 2
Docket Nos. 50-335 and 50-389
Proposed License Amendments

ATTACHMENT 4 to L-99-228

ST. LUCIE UNIT 2 MARKED-UP TECHNICAL SPECIFICATION PAGES

Page 3/4 8-1

Bases Page B 3/4 8-1

3/4.8 ELECTRICAL POWER SYSTEMS

3/4.8.1 A.C. SOURCES

OPERATING

LIMITING CONDITION FOR OPERATION

3.8.1.1 As a minimum, the following A.C. electrical power sources shall be OPERABLE:

a. Two physically independent circuits between the offsite transmission network and the onsite Class 1E distribution system, and

b. Two separate and independent diesel generators, each with:

1. Two separate engine-mounted fuel tanks containing a minimum volume of 200 gallons of fuel each,

2. A separate fuel storage system containing a minimum volume of 40,000 gallons of fuel, and

3. A separate fuel transfer pump.

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

ACTION:

a. With one offsite circuit of 3.8.1.1.a inoperable, except as provided in Action f. below, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. Restore the offsite circuit to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and COLD SHUTDOWN within the following 30 hours.

b. With one diesel generator of 3.8.1.1.b inoperable, demonstrate the OPERABILITY of the A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter; and if the EDG became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned preventative maintenance or testing, demonstrate the OPERABILITY of the remaining OPERABLE EDG by performing Surveillance Requirement 4.8.1.1.2a.4 within 8 hours, unless it can be confirmed that the cause of the inoperable EDG does not exist on the remaining EDG*; restore the diesel generator to OPERABLE status within ~~72 hours~~ 14 days or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours. Additionally, verify within 2 hours or be in HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours that:

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* If the absence of any common-cause failure cannot be confirmed, this test shall be completed regardless of when the inoperable EDG is restored to OPERABILITY.

18 days

BASES

3/4.8.1, 3/4.8.2 and 3/4.8.3 A.C. SOURCES, D.C. SOURCES and ONSITE POWER DISTRIBUTION SYSTEMS

The OPERABILITY of the A.C. and D.C. power sources and associated distribution systems during operation ensures that sufficient power will be available to supply the safety related equipment required for 1) the safe shutdown of the facility and 2) the mitigation and control of accident conditions within the facility. The minimum specified independent and redundant A.C. and D.C. power sources and distribution systems satisfy the requirements of General Design Criterion 17 of Appendix "A" to 10 CFR 50.

The ACTION requirements specified for the levels of degradation of the power sources provide restriction upon continued facility operation commensurate with the level of degradation. The OPERABILITY of the power sources are consistent with the initial condition assumptions of the safety analyses and are based upon maintaining at least one redundant set of onsite A.C. and D.C. power sources and associated distribution systems OPERABLE during accident conditions coincident with an assumed loss of offsite power and single failure of the other onsite A.C. source. The A.C. and D.C. source allowable out-of-service times are based on Regulatory Guide 1.93, "Availability of Electrical Power Sources," December 1974. When one diesel generator is inoperable, there is an additional ACTION requirement to verify that all required systems, subsystems, trains, components and devices, that depend on the remaining OPERABLE diesel generator as a source of emergency power, are also OPERABLE, and that the steam-driven auxiliary feedwater pump is OPERABLE. This requirement is intended to provide assurance that a loss of offsite power event will not result in a complete loss of safety function of critical systems during the period one of the diesel generators is inoperable. The term verify as used in this context means to administratively check by examining logs or other information to determine if certain components are out-of-service for maintenance or other reasons. It does not mean to perform the surveillance requirements needed to demonstrate the OPERABILITY of the component.

All EDG inoperabilities must be investigated for common-cause failures regardless of how long the EDG inoperability persists. When one diesel generator is inoperable, required ACTIONS 3.8.1.1.b and 3.8.1.1.c provide an allowance to avoid unnecessary testing of EDGs. If it can be determined that the cause of the inoperable EDG does not exist on the remaining OPERABLE EDG, then SR 4.8.1.1.2.a.4 does not have to be performed. Eight (8) hours is reasonable to confirm that the OPERABLE EDG is not affected by the same problem as the inoperable EDG. If it cannot otherwise be determined that the cause of the initial inoperable EDG does not exist on the remaining EDG, then satisfactory performance of SR 4.8.1.1.2.a.4 suffices to provide assurance of continued OPERABILITY of that EDG. If the cause of the initial inoperability exists on the remaining OPERABLE EDG, that EDG would also be declared inoperable upon discovery, and ACTION 3.8.1.1.e would be entered. Once the failure is repaired (on either EDG), the common-cause failure no longer exists.

Add New Paragraph

TS 3.8.1.1, ACTION "b" provides an allowed outage/action completion time (AOT) of up to 14 days to restore a single inoperable diesel generator to operable status. This AOT is based on the findings of a deterministic and probabilistic safety analysis and is referred to as a "risk-informed" AOT. Entry into this action requires that a risk assessment be performed in accordance with the Configuration Risk Management Program (CRMP), which is described in the Administrative Procedure that implements the Maintenance Rule pursuant to 10 CFR 50.65.

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