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SUBJECT: Forwards response to RAI during 930726 meeting re restart of PVNGS,Unit 2,in support of Unit 2 SGTR rept & SG tube evaluation submitted via 930718 & 25 ltrs.Proprietary info also encl.Proprietary info withheld.

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102-02593-WFC/TRB/JRP
July 30, 1993

WILLIAM F. CONWAY
EXECUTIVE VICE PRESIDENT
NUCLEAR

U. S. Nuclear Regulatory Commission
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Washington, D. C. 20555

References: 1) Letter 102-20569, dated July 18, 1993, from W. F. Conway, Executive Vice President, Nuclear, APS, to USNRC

2) Letter 102-20585, dated July 25, 1993, from W. F. Conway, Executive Vice President, Nuclear, APS, to USNRC

Dear Sirs:

Subject: Palo Verde Nuclear Generating Station (PVNGS)
Units 1, 2 and 3
Docket Nos. STN 50-528/529/530
Steam Generator Tube Rupture Analysis
File: 93-056-026

This letter is being provided in response to an NRC request for additional information concerning the PVNGS Unit 2 Steam Generator Tube Rupture Report (Reference 1) and the Steam Generator Tube Evaluation (Reference 2).

On July 26, 1993, Arizona Public Service Company (APS) met with NRC management and staff to discuss the information submitted in References 1 and 2. It was during this meeting that members of the NRC staff requested APS provide additional information in support of the referenced letters.

In accordance with this request, enclosed for NRC review, is the APS response. In addition, APS requests NRC review of the enclosed material and approval of Unit 2 restart by August 9, 1993.

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Should you have any questions, please contact Thomas R. Bradish at (602) 393-5421.

Sincerely,

WFConway

WFC/TRB/JRP/bcf

Enclosure:

cc: B. H. Faulkenberry
C. M. Trammell
J. A. Sloan

The following information is provided in response to questions asked by the NRC staff at the July 26, 1993, meeting discussing the restart of PVNGS Unit 2.

1. The NRC requested information regarding the assumptions used in the risk assessment for the probability of a multiple tube rupture event. This was provided by FAX directly to Mr. Steve Long, and discussed with him during a conference call on July 27, 1993, (Attachment 1).

2. Provide information regarding changes to EOPs and operator training completed as a result of the Unit 2 SGTR (Attachment 2).

3. APS was requested to perform the calculation of allowed run time using Regulatory Guide 1.121 methodology and a burst pressure correlation more conservative than the Framatome correlation presented in Reference 1. In response to this request the correlation described in NUREG/CR-0718 "Steam Generator Integrity Program-Phase I Report" (Battelle correlation) was used to calculate minimum required wall thickness to meet R.G. 1.121 limits, and the operating time to reach the limits was determined to be approximately 4.5 months. This analysis is provided in Attachment 3. However, the APS Engineering staff maintains that the proper correlation to use is the Framatome correlation described in EPRI report NP-6865-L "Steam Generator Tube Integrity, Volume 1" and discussed in Reference 1. This conclusion is based on the excellent agreement of the Framatome calculations with actual tube burst pressures determined by laboratory tests conducted on tubing removed from PVNGS Unit 2 S/G 22. Therefore, the correct maximum operating time until the next Eddy Current Examination is six full power months.

4. The basis for the EPRI probability of detection discussed in Reference 1 is given in Attachment 4.

5. Leak testing of Unit 2 S/G 22 was conducted the week of July 19, by filling the secondary side with water and pressurizing to 200 psig while observing the primary side for evidence of leakage. A small leak was detected from a welded plug, and three Inconel 690 mechanical plugs were damp but not dripping water. All leaking plugs had been in place during the last operating cycle. Subsequent to the test water activated dye was used to identify the leakage paths. In the case of the welded plug the leakage was determined to be from the weld area. One mechanical plug showed leakage around the outer diameter of the plug, and two mechanical plugs did not show any leakage under static head. The centers of all three mechanical plugs did not activate the dye which indicates the plugs are not passing leakage due to a crack. The pattern of boric acid around all three mechanical plugs is very similar, so it was concluded that the two mechanical plugs which did not leak under static head also have a leak at their outer diameter. The tubes will be replugged.

Mr. Emmett Murphy explained that it was his understanding that Kewaunee Station had experienced a plug leak on the order of 200 GPD, and he asked how that information applied to the leak-before-break scenario at PVNGS. To resolve this issue the staff at Kewaunee Station was contacted for information.

The average leak rate at Kewaunee was approximately 100 GPD with daily values ranging up to 50 GPD on either side of this value. This was determined to be coming from a defective weld on a welded plug, and the fluctuation in leak rate was attributed to uncertainties in the analysis methods. There was no physical theory to account for the fluctuations.

In contrast with the Kewaunee leaking plug, the total plug leakage in PVNGS Unit 2 S/G 22 was calculated to have been approximately 2.5 GPD based on observed leakage during testing conducted in the outage. This value is consistent with the small relatively constant rate observed since July 1992, and is only a few percent of the spike observed in early March. Minor variation in plug leakage does occur, but it is unlikely that it would cause an order of magnitude change for a short period of time. It is more likely that another source of leakage was present.

It is not possible to state conclusively that the ruptured tube caused the spike in leak rate that occurred in early March. However, this scenario is consistent with the industry experience of entering forced shutdowns due to increased leakage rather than experiencing frequent tube ruptures.

6. Additional information was requested regarding the assumptions and methodology used in the statistical study of crack growth to determine the operating interval prior to the next inspection of steam generators in Unit 2. Attachment 5 provides the contractor's description of the analysis and assumptions.

ENCLOSURE

RESPONSE TO NRC QUESTIONS

2.2 Calculation Of Single Tube Rupture Initiating Frequency:

As an upper bound estimate it is assumed that the Unit 2 data is indicative of the tube failure rate in Units 1 and 3 steam generators. As a lower bound estimate it is assumed that the problem is unique to Unit 2, and that one of the factors unique to Unit 2 is necessary before the crack propagation rates seen in SG22 can occur. In order to estimate a best estimate probability, the upper bound is taken as the 95% percentile value of a lognormal distribution, and the lower bound is taken as the 5% percentile value, and the resulting mean value is used as the best estimate value.

1) Calculation of Upper Bound Value (assumes Unit 2 data applies to Unit 1 and 3 generators)

   Unit 2, exhibited a single tube which degraded to the extent that it failed, or would have been expected to fail within the period of the scheduled fuel cycle. This failure experience is indicative of an underlying failure rate of 4.59E-5 failures per tube per refueling cycle [1/21,800]. The probability that zero of 21,800 SG tubes fail within a refueling cycle given a failure rate off 4.59E-5 is estimated as 0.37 [(1-4.59E-5)**21800], corresponding to a 0.63 probability of one or more tube failures within a refueling cycle. However tube failure probability does not correspond directly to tube rupture probability. Given the compensatory measures which have been implemented in Units 1 and 3 there is a reasonably high likelihood that the plant could be shutdown and depressurized before the tube failure is severe enough to require ECCS injection. This reduction factor was estimated as 0.5 based on plant shutdowns due to leakage (0.03 from NUREG/CR-3862) versus the frequency of ruptures (.015 from NUREG- 0844).
   Therefore the upper bound probability of a tube rupture during a refueling cycle for Units 1,3 is estimated as .315 (0.63*0.5). This number was adjusted upward to 0.33 for Units 1 and 3, to account for the slightly larger projected fuel burnup in U1C4 and U3C4 relative to U2C4 (437 EFPD versus 413 EFPD).

2) Calculation of Lower Bound Value

   As a lower bound estimate it is assumed that the combination of factors which caused the rupture event in SG22 during refueling cycle 4 are unique to SG22. Then the tube rupture frequency in the PVNGS PRA value of 0.016 tube ruptures per year is applied. For conservatism, and since tube ruptures due to crack propagation are most likely late in the cycle, this is taken as a 0.016 probability over the remaining portion of the fuel cycle in Units 1 and 3.

3) Calculation of Best Estimate Value:

   Taking the upper bound value as the 95th percentile value of a lognormal distribution, and the lower bound is taken as the 5th percentile value, the mean value is calculated as 0.11. The EF is 4.54, and the mean value is estimated as 0.11 [.016 * 4.54 * 1.53].

The information contained in this Attachment is undergoing APS internal review as stated in letter #102-02585; W. F. Conway APS to U.S. N.R.C. dated July 25, 1993.

2.3 Evaluation of the Probability of Consequential Tube Rupture Events (Single and Multiple), and Development of Multiple Tube Rupture Initiating Event Probabilities

The events which are likely to result in large differential pressures across SG tubes for PVNGS are Main Steam Line Break (MSLB) and Main Feedline Break (MFLB). The probability of a large steamline break: 4.3E-4 events per year (5.4E-5 for remaining 1.5 months of Unit 1 Cycle 4). The probability of large feedline break: 3.1E-4; however feedline breaks would not result in a loss of ruptured steam generator inventory from the containment, so RWT depletion is not a concern. (PVNGS has check valves inside containment). The probability of a Stuck Open Secondary Valve was estimated as .006 events per year for events where the valve fails more than 25% open (7.5E-4 for final 1.5 months of Unit 1 Cycle 4). Secondary Valve leakage events, and events where steam is limited to less than 20 percent of design steam flow were excluded on the basis that differential pressures would be significantly reduced for these events. Section 2.3.2 calculates the probability that one or more tube ruptures occurs as a consequence of a Main Steamline Break (MSLB) or due to a substantially Stuck Open Secondary Safety Valve (SOSV).

A Main Steamline Break (MSLB) Event is assumed to result in tube differential pressures in the range of 2000 - 2200 psi. Such pressures can reasonably be postulated following a steam line break when typical operator response is credited (and if no tube ruptures occur as a consequence). Although higher pressures are possible if the operator does not control the subsequent heatup and repressurization and no tubes fail, best estimate transient analysis indicates that for a single guillotine rupture of a single tube the peak primary pressure is limited to approximately 2150 - 2200 even without crediting operator action [PVNGS has low head (about 1800 psi) HPSI pumps, and low capacity charging pumps]. Although more time is available following a Stuck Open Secondary Valve event for the operator to prevent a significant repressurization, this event was also conservatively assumed to result in a differential pressure of approximately 2150 - 2200 psid in the ruptured steam generator.

2.3.1 Probability of a Single Transient Induced Tube Rupture

Upper Bound Estimate (1 Tube; Assumes Unit 2 data is applicable to Units 1 and 3): The data from end of cycle 4 of Unit 2, indicates that there were three tubes of approximately 21,800 that might reasonably have been postulated to fail based upon eddy current data and a best estimate burst strength from NUREG/CR - 5117 if a steamline break had occurred at end of cycle (2100 - 2200 psid applied). Although a worst case DEGB MSLB could reasonably be postulated to result in differential pressures as high as 2500 psid if no operator action is assumed, this would be the case for only a small percentage of MSLB/SOSV events, only six tubes would exceed their predicted burst pressure, and the total leakage through those 6 tubes would be expected (best estimate) to be commensurate with the break flow assumed in this study if three tubes were to fail. Therefore, although the probability that a single tube rupture (once a single rupture occurs peak differential pressure decreases significantly) occurs following a DEGB MSLB may be somewhat underpredicted, it is underestimated by a factor of two for less than ten percent of MSLB/SOSV events which would increase the single tube rupture probability by less than ten percent which has a negligible affect on the analysis results. In addition there were approximately 19 tubes with cracks in excess of 1.2 inches long without quantifiable indications, which indicates high confidence (estimated as 95% confidence) that the cracks were less than 70% through wall and therefore not structurally significant (i.e - not in excess of Reg. Guide 1.121 allowables). This data suggests a failure rate of 1.92E-4 per tube per cycle [3.95/21,800 * 1.06 where the 6% increase is taken to account for slightly greater EFPH for U1C4] if tube degradation is uniform in both

steam generators, and 3.84E-4 per tube per cycle [3.95/10900 * 1.06] in the generator in which tube degradation is concentrated if tube degradation is concentrated in a single steam generator as was the case in Unit 2. From the binomial the probability that 1 of 10,900 tubes fails in the affected steam generator is estimated as 0.11 given a steam line break at or near end of cycle [10900 * (1-1.92E-4)**10899 * 1.92E-4 * 0.33 + 10900 * (1-3.84E-4)**10899 * 3.84E-4 * 0.5 * 0.67 where 0.67 weight is given to degradation being concentrated within a single steam generator as was the case in Unit 2, and 0.5 is the probability that the steam line break is in the most degraded generator].

Lower Bound Estimate (1 Tube):
The lower bound estimate was based upon a tube failure probability of 4.6E-6 per cycle which is based on the expectation of finding 1 tube every 10 refueling cycles with insufficient capacity to withstand the steamline break differential pressure (0.1/ 21,800 = 4.6E-6). This rate was based on the industry eddy current results which have infrequently identified tubes with degradation which would prevent the tube from sustaining 2500 psid differential pressure. From the binomial equation the probability that 1 of 10,900 affected tubes fails given a failure rate of 4.6E-6 is .048.

Best Estimate Value (1 Tube):
The best estimate value was calculated by fitting a lognormal distribution to the data above. The resulting best estimate value is 0.075.

2.3.2 Probability of a Multiple Transient Induced Tube Rupture (2 - 4 Tubes)

Upper Bound Estimate (2-4 Tubes):
For the purposes of estimating the likelihood of multiple tube ruptures, it was once again considered that the tube degradation does not occur uniformly in both steam generators, but that 1 steam generator may be affected to a much greater extent. Since this was the case in Unit 2, this possibility can not be neglected in Units 1 and 3, and this assumption was given a weighting of 0.67 (tube failure rate is 3.84E-4 in the generator in which tube degradation is concentrated, where tube failure is defined as loss of capacity to withstand MSLB differential pressures), and the alternative hypothesis was given a weighting of 0.33 (a uniform tube failure rate of 1.92E-4). Then the probability of the rupture of between 2 and 4 tubes in the steam generator is estimated from the binomial formula as 0.48. {[10,900*10899/2 * 3.84E-4**2 * (1-3.84E-4)**10898 + 10900*10899*10898/6 * 3.84E-4**3 * (1-3.84E-4)**10897 + 10,900*10899*10898 * 10897/24 * (3.84E-4**4) * (1-3.84E-4)**10896] * 0.5 * 0.67 + [10,900*10899/2 * 1.92E-4**2 * (1-1.92E-4)**10898 + 10900*10899*10898/6 * 1.92E-4**3 * (1-1.92E-4)**10897 + 10,900*10899*10898*10897/24 * (1.92E-4**4) * (1-1.92E-4)**10896] * 0.33 + .12 from section 2.3.3}

Lower Bound Estimate (2 - 4 Tubes):
The lower bound estimate was based upon a tube failure probability of 4.6E-6 per cycle which is based on the expectation of finding 1 tube every 10 refueling cycles with insufficient capacity to withstand the steamline break differential pressure (0.1/ 21,800 = 4.6E-6). From the binomial equation the probability that between 2 and 4 tubes fail (out of 10,900) is 1.2E-3.

Best Estimate Value (2 - 4 Tubes):

The best estimate value was calculated by fitting a lognormal distribution to the data above. The resulting best estimate value is 0.13.

2.3.3 Probability of a Multiple Transient Induced Tube Rupture (5 -10 Tubes)

Upper Bound Estimate (5-10 Tubes):
From the binomial equation (similar to the development in Section 2.5.2.2) the probability that between five and ten tubes fail given an applied differential pressure of 2200 psid is calculated as 0.155. However best estimate transient analysis indicates that pressure differentials across the tubes in excess of 1450 psid cannot be generated or maintained following the failure of 4 steam generator tubes (best estimate rupture area estimated as $4\pi r^{**}2$ where r is the inside tube diameter of 0.375 inches). Therefore in order to get more than 4 tubes to fail requires either that more than 4 tubes fail at an applied differential pressure of 1450 psid or less, or while differential pressure is decreasing towards 1450 psid. From NUREG-0844 (Page 3-4) the probability that between five to ten tubes fail at 1450 psid can be estimated as follows:

$P_{5\text{-}10(1450\ psid)} = P_{5\text{-}10(2150\ psid)} * [\Delta P(1450\ psid)/\ \Delta P(2150)]^{**}2$

Taking the normal operating differential pressure as 1250 psid:

$P_{5\text{-}10(1450\ psid)} = P_{5\text{-}10(2150\ psid)} * [200/900]^{**}2$

$P_{5\text{-}10(1450\ psid)} = .0498 * P_{5\text{-}10(2150\ psid)} = .0498 * .155 = 7.7E\text{-}3$

However to account for some uncertainty in the peak pressure calculation, and to account for the possibility that multiple tubes fail at nearly the same pressure it is conservatively assumed that the probability of tube rupture is proportional to the increased differential pressure rather than as the square of the increased differential pressure. In this case the probability that 5 - 10 tubes fail given an applied differential pressure of 1450 psid is estimated as .034 [.155 * (200/900)]. Therefore .034 is conservatively taken as the upper bound estimate. For the cases where five to ten tubes would have failed at 2150 psid, but did not because the pressure rise was terminated by the time the fourth tube failed, it is necessary to add this probability to the probability that two to four tubes fail which accounts for the 0.12 probability (.155 - .034) added to the likelihood that two to four tubes fail in section 2.3.2. Similarly this probability is increased by 1.2E-3 from Section 2.3.4 below to account for cases where more than 10 tubes would have failed at 2150 psid, but did not because the pressure rise was terminated by the first several tube failures. The total upper bound estimate for five to ten tubes is then estimated as 0.035

Lower Bound Estimate (5-10 Tubes)
From the binomial equation the probability that more than four tubes fail at an applied differential pressure of 2150 psid is negligible (<1E-7). For the purposes of constructing a conservative distribution, a error factor of 100 is assumed which results in a lower bound estimate of 3.5E-6.

Best Estimate Value (5-10 Tubes)
The best estimate value was calculated by fitting a lognormal distribution to the data above. The resulting best estimate value is 0.018.

2.3.4 Probability of Multiple Transient Induced Tube Rupture (>10 tubes)

Upper Bound Estimate (>10 Tubes)
From the binomial equation (similar to the development in Section 2.3.2) the probability that more than ten tubes fail given an applied differential pressure of 2150

psid is calculated as 1.3E-3. However best estimate transient analysis indicates that pressure differentials across the tubes in excess of 100 psid above normal would not be generated or maintained following a SOSV with the subsequent failure of 10 steam generator tubes .Therefore it is very unlikely that more than ten tubes will fail following a SOSV event. The probability that ten or more tubes fail following a SOSV event is then estimated from NUREG-0844 as:

$P_{>10(1350\ psid)} = P_{>10(2150\ psid)} * [\Delta P(1350\ psid)/ \Delta P(2150)]**2$
Taking the normal operating differential pressure as 1250 psid:
$P_{>10(1350\ psid)} = P_{>10(2150\ psid)} * [100/900]**2$
$P_{>10(1350\ psid)} = 0.012 * P_{>10(2150\ psid)} = .012 * .0013 = 1.6E-5$

For a DEGB of the Main Steamline Piping an increased differential pressure of 200 psid above normal could reasonably be postulated and a corresponding probability of 6.4E-5 would be calculated. However most Main Steamline breaks would be less severe than the worst case double ended guillotine break and the probability of having more than 10 tubes fail would be further reduced below 6.4E-5

If it is once again conservatively assumed that the probability of tube rupture is proportional to the increased differential pressure rather than as the square of the increased differential pressure as was done in section 2.3.2 then the estimated probability increases to 1.4E-4 for the SOSV case. Therefore 1.4E-4 is conservatively taken as the upper bound estimate for the SOSV case. Since SOSV events are much more likely than double ended guillotine breaks of the Main Steam piping, and since the majority of Main Steam Line breaks would result in differential pressure increases significantly below 200 psid, this value is assumed to apply to both the MSLB and SOSV events. In cases where more than ten tubes would have failed at 2150 psid, but did not because the pressure rise was terminated before the tenth tube failed, the associated probability (1.3E-3 - 1.4E-4 = 1.2E-3) was added to the probability that five to ten tubes fail, which accounts for the 1.2E-3 added to the upper bound probability in section 2.5.2.3.

Lower Bound Estimate (>10 Tubes):
From the binomial equation the probability that more than four tubes fail at an applied differential pressure of 2150 psid is negligible (<<1E-7). For the purposes of constructing a conservative distribution, a error factor of 100 is assumed which results in a lower bound estimate of 1.4E-8.

Best Estimate Value (5-10 Tubes):
The best estimate value is calculated by fitting a lognormal distribution to the data above. The resulting mean probability is 7.0E-5.

2.3.5 Calculation of the Probability of a Multiple Steam Generator Tube Rupture as an Initiating Event:

In addition the probability that one or more tubes fails during an unexpected operational occurrence (such as a turbine trip, without steam bypass control system operation) was calculated. It was desired to estimate the likelihood of a multiple tube rupture as an initiating event. The likelihood that two tubes propagate randomly and independently to failure within 1 day is low, especially when it is considered that following the first rupture, the plant would be promptly depressurized. However, a plant upset in the last weeks of operation, such as a turbine trip with failure of steam bypass is possible, and could result in increased differential pressures

TABLE 2.3. - 1
SUMMARY OF RESULTS
First Column Represents Conditional Probability given MSLB/SOSV

	MSLB/SOSV	SGTR Initiating Event Frequency (Per Refueling Cycle)
Upper Bound Estimate (1 Tube)	0.11	0.33 (Section 2.0)
Lower Bound Estimate (1 Tube)	0.048	0.016 (Section 2.0)
Best Estimate Value (1 Tube)	0.075	0.11 (Section 2.0)
Upper Bound Estimate (2-4 Tubes)	.48	4.2E-3
Lower Bound Estimate (2-4 Tubes)	1.2E-3	1.0E-5
Best Estimate Value (2-4 Tubes)	.13	1.1E-3
Upper Bound Estimate (5-10 Tubes)	0.035	3.0E-4
Lower Bound Estimate (5-10Tubes)	3.5E-6	3.0E-8
Best Estimate Value (5-10 Tubes)	.018	1.6E-4
Upper Bound Estimate (>10 Tubes)	1.4E-4	1.2E-6
Lower Bound Estimate (>10 Tubes)	1.4E-8	1.2E-10
Best Estimate Value (>10 Tubes)	7.0E-5	6.1E-7

across the tubes of approximately 200 psid based upon conservative Chapter 15 analysis. In order to calculate a conservative multiple tube rupture initiating event frequency it is assumed that there is a 50% chance of a transient which increases tube differential pressure by 100 psid (conservative engineering judgement) and a 5% chance that a transient event increases differential pressure by 200 psid above normal. From NUREG-0844 (Page 3-4) the probability that a specific number of tubes fail from a pressure excursion event can be estimated as:

$$P_{i(\text{Pressure Transient})} = P_{i(\text{MSLB})} * [\Delta P(\text{Pressure Transient}) / \Delta P(\text{MSLB})]^{**2}$$

where:

$P_{i(\text{Pressure Transient})}$ = Probability that i tubes fail given a pressure transient
$P_{i(\text{MSLB})}$ = Probability that i tubes fail given a MSLB (Main Steamline Break)
ΔP(Pressure Transient) = Increased tube differential pressure that results from pressure transient event (100 or 200 psid from above)
ΔP(MSLB) = Increased tube differential pressure which results from a MSLB (900 psid)

Accounting for the probability of a significant pressure excursion events before the end of the cycle (5% chance of a 200 psid pressure transient, and 50% chance of a 100 psid transient) the probability that a multiple tube rupture initiating event occurs before end of cycle is estimated as:

$$P_{i(\text{Pressure Transient})} = P_{i(\text{MSLB})} [\, 0.5 * (100/900)^{**2} + 0.05 * (200 / 900)^{**2}]$$
$$P_{i(\text{Pressure Transient})} = P_{i(\text{MSLB})} * 8.7\text{E-}3$$

Therefore the results in Table 2.3-1 can be multiplied by 8.7E-3 to get a conservative multiple tube rupture initiating event probability for the remainder of the cycle. The results are conservative in that no credit is taken for the fact that the magnitude of the pressure excursion would be significantly reduced for following the failure of one to three tubes, and because the likelihood of a significant pressure excursion was conservatively assessed. Although some credit was taken in the MSLB case for reduction in the differential pressure if more than 4 tubes fail, the pressure increase for a transient event with failure of Steam Bypass and/or Reactor Power Cutback would be similarly decreased and therefore the reduction factors above are judged appropriate. These analysis conservatisms are partially offset by the fact that all the tubes in both generators would be exposed to the pressure transient, whereas only the tubes in the affected steam generator see significantly increased differential pressure during the MSLB event.

Attachment 2

NRC QUESTION

I. For the postulated MSLB (upstream of the MSIV and outside containment) induced multiple SGTR, provide the following:

1. Describe EOPs used during the entire transient including transition points in each procedure.

APS RESPONSE

A. Operators enter Emergency Operations on reactor trip and perform the stabilization and diagnosis.

- Feed is terminated to the affected SG by the Main Steam Isolation Signal initiated by low SG pressure and high differential pressure lockout.
- The Diagnostic Logic Tree will lead to the Excess Steam Demand (ESD) procedure.

B. Operators enter the ESD procedure and stabilize the plant.

- Operators throttle HPSI when level increases to >33%.
- As the affected SG blows down, operators open the ADV on the unaffected loop.

C. Operators conclude that the ESD procedure is not mitigating the event and enter the Functional Recovery Procedure (FRP).

- Operators should become aware that more than an ESD has occurred because of the need to maintain some HPSI flow for RCS inventory control (pressurizer level will decrease after HPSI is throttled). A deduction based on observation of normal containment sump levels and HPSI flow should lead the operators to conclude that an SGTR or other loss of RCS inventory outside of the containment is occurring. It is reasonable that the operator, backed by the STA, will be able to reach this conclusion. A simulator scenario approximating this event was run with licensed operators, the crew recognized that a SGTR was in progress approximately 40 minutes after start of the event, supporting the conclusion that operators can recognize the event using current procedures.

- Other (Radiation Protection) reports of activity release may cue operators to identify an SGTR.

D. Operators may identify an SGTR in the affected SG. If this is identified, then the affected SG is fed to tube coverage per the FRP.

E. A plant depressurization and cooldown begins per the FRP. This will be done regardless of whether the SGTR has been identified. In fact, the RCS cools down throughout the event from the SGTR steaming out of the faulted steam generator. If operators feed the affected steam generator for tube coverage, that will increase the cooldown rate.

- The plant is depressurized with main sprays, aux sprays, or pressurizer vents.

- Shutdown Cooling (SDC) is initiated at ≈300°F and ≈350 psia, about 3 hours after the start of the event and cold shutdown conditions are reached 4 hours after SDC is placed in service. This is performed per the General Operating Procedures. The time estimated is conservative and within the capacity of one SDC train. The time is based on plant experience and not the capacity of the SDC system.

Operator briefings on this scenario began on July 28, 1993, and will be completed by August 7, 1993.

NRC QUESTION

2. Describe proposed EOP enhancements and their implementation plan.

APS RESPONSE

Two enhancements will be made to the EOPs in response to the SGTR/MSLB scenario.

A. The Safety Function Status Check of the Excess Steam Demand Procedure will be modified to ensure the performer exits to the functional Recovery Procedure if either of the following indications of the SGTR/MSLB scenario exist:

- If safety injection flow is needed to maintain pressurizer level after throttling criteria have been met. (RCS inventory is being maintained by continued makeup subsequent to the expected makeup during an ESD.)

- If radiation monitors and steam generator samples are not available, then direct radiation and contamination surveys of the steam generator release points will be initiated (safety valves and atmospheric dump valves).

B. The check within the Functional Recovery for indications of a possible SGTR will be broadened to include the checks described above (continued RCS makeup during an apparent ESD and local radiation checks when monitors and sampling are unavailable).

- These enhancements will be added to the EOP change currently in progress. This change will be approved by 9/7 and operators will be trained during the subsequent requalification cycle. The training will be completed and the procedures will be made effective by 10/31.

NRC QUESTION

3. Describe the EOP modifications made after the Unit 2 SGTR.

APS ANSWER

A number of procedure changes were identified after the Unit 2 SGTR; some were made shortly after the event and others are being put in during later changes.

A. The changes that have already been incorporated into the EOPs are:

- Consider previous as well as current radiation monitor alarms for diagnosis.

- Observe radiation monitor trends as well as alarms for diagnosis.

- Additional checks for identifying a steam generator with a tube rupture in both the SGTR and Functional Recovery Procedure. The added checks were to look for differential feedflow between steam generators to maintain level.

- Made the checks for an SGTR within the FRP continuously applicable.

B. Changes being incorporated into the EOPs to be made effective 10/31:

- Transfer secondary system sump discharge promptly to liquid radwaste systems to minimize the spread of contamination following an SGTR.

- Transfer the affected unit's auxiliary steam source to an unaffected unit to minimize the spread of contamination following an SGTR.
- Modified feedwater system operation to allow continued use of steam generator blowdown demineralizers throughout the recovery of an SGTR.

- Modified feedwater and condensate system operation to allow use of main feedwater and condensate throughout the recovery of an SGTR to minimize the amount of makeup water added to the secondary system.

- Add directions that effluent releases must be monitored and maintained below limits set by the TSC during blowdown of the affected steam generator for level control of cooldown.

C. Further changes are being evaluated:

- Should affected steam generator level be controlled by reverse flow to the RCS during an SGTR? (This evaluation is being done by the CE Owner's Group.)

- Should potential hydrogen accumulations in the affected steam generator be addressed by procedures?

Operator training has been conducted to address the lessons learned from the Unit 2 event and further training is planned:

D. Training that has been conducted:

- Operators have been briefed on the Unit 2 event and the short term changes that were made to the EOPs.

- Operators have participated in simulator scenarios during requalification training that closely paralleled the Unit 2 event. The simulator has been modified to more realistically model the plant, particularly the response of the Radiation Monitoring System to an SGTR.

E. Operators will be trained during requalification training on the 10/31 changes. This will be completed before the procedures are effective.

NRC QUESTION

II. For the postulated design basis SGTR and multiple SGTR, provide the following:

1. Describe EOPs used during the entire transient including transition points in each procedure.

APS RESPONSE

A. This description is based on current EOPs. This description assumes that all radiation monitors are operable and that the affected steam generator can be sampled. It also assumes that RCS subcooling does not go below the low limit during the recovery. These assumptions are consistent with the SGTR without LOP described in the PVNGS UFSAR.

B. Operators respond to radiation monitor alarms (any combination of main steam line monitors, condenser exhaust monitors, and steam generator blowdown monitors).

C. Operators enter Emergency Operations on reactor trip, perform standard post-trip actions, and diagnose an SGTR.

- 2 RCPs are stopped when RCS pressure decreases below the Safety Injection Actuation System setpoint.
- The diagnosis is based on secondary radiation monitor alarms or trends.

D. Operators enter the SGTR procedure and isolate the affected steam generator.

- The RCS is depressurized to within 100 psid of the minimum subcooling limit.
- the affected steam generator is identified, cooled down to prevent lifting the MSSVs and isolated.

E. The RCS is cooled down to shutdown cooling entry conditions.

- HPSI is throttled as pressurizer level is restored and RCS subcooling is maintained.

F. Level in the affected steam generator is controlled by blowing down to the condenser (if condenser cooling is available) or intermittently steaming to atmosphere. Leakage into the affected steam generator is reduced by minimizing the differential pressure between the steam generator and the RCS.

G. Shutdown Cooling (SDC) is initiated at ≈300°F and ≈350 psia and cold shutdown conditions are reached after SDC is placed in service. This is performed per the General Operating Procedures.

The actions taken for a multiple SGTR would be similar to the single SGTR, except that all RCPs would be stopped if RCS subcooling decreased below the minimum limit and the affected steam generator level reduction would have to be accomplished sooner. The current SGTR EOP provides for both of these occurrences.

NRC QUESTION

2. Describe the consequences when all secondary system radiation monitors are not available.

APS RESPONSE

If all secondary radiation monitors are not available, the affect on the performance of the EOPs would be as follows:

A. Operators would not diagnose a SGTR.. With the current EOPs, the diagnosis would lead to the Reactor Trip procedure, unless RCS minimum subcooling was lost due to a multiple SGTR. Then the diagnosis would lead to a Loss of Coolant Accident.

- The reactor trip procedure entry conditions would not be satisfied due to the low pressurizer level and pressure, so the CRS would go to the Functional Recovery Procedure.

- The LOCA procedure entry conditions would not be satisfied due to the lack of confirming radiation monitor indications, so the CRS would go to the Functional Recovery Procedure.

B. Once in the FRP, the performer is directed to check for indications of an SGTR. These include non-rad monitor checks; SG level increasing without feed, differential feedflow between SGs, and SG samples indications of activity. These checks will lead the performer to identify that an SGTR has occurred.

C. When that determination is made that an SGTR has occurred, the performer is directed to an attachment within the FRP that has the same steps to mitigate the SGTR as the SGTR procedure itself. The recovery then proceeds as it does in the SGTR procedure.

Attachment 3

Regulatory Guide 1.121 Evaluation Using a More Conservative Burst Correlation

At the request of the NRC, APS has performed a comparative Regulatory Guide 1.121 evaluation using a more conservative burst correlation than originally used by APS in the attachment to letter 102-02569-WFC/JRP dated July 18,1993 (Reference 1) and discussed in a meeting with NRC on July 26, 1993. Use of this more conservative correlation developed by Battelle reduces the allowable operating cycle length from 6 months to 4.5 months. However, as described below, it is APS's position that our Regulatory Guide evaluation already contains sufficient conservatism and the additional conservatism resulting from the use of the Battelle correlation is not warranted.

The original evaluation utilized a burst correlation developed for EPRI by Framatome as described in EPRI report NP-6865-L "Steam Generator Tube Integrity, Volume 1". Using this correlation, the maximum allowable crack depth as a function of crack length was determined as illustrated in Figure X-h in Reference 1 and reproduced here as Figure 1. A similar correlation predicting the burst pressure of tubes with axial flaws was developed by Battelle for NRC and presented in NUREG/CR-0718 "Steam Generator Integrity Program-Phase I Report". The empirical burst correlation developed by Battelle is:

$$\Delta p = \Delta p_0 \left[1 - \frac{a}{t} + \frac{a}{t} e^{-0.373 L/\sqrt{Rt}} \right]$$

where,

Δp = predicted burst pressure
Δp_0 = burst pressure for undefective tube
a/t = through wall penetration (%)
L = axial flaw length (in)
R = inner tube radius (in)
t = tube wall thickness (in)

Using the Battelle correlation, the maximum allowable crack depth as a function of length can be determined and compared with the Framatome correlation results as illustrated in Figure 2. This comparison indicates that the Battelle correlation yields a more conservative (i.e. shallower allowable crack depth) result for cracks longer than approximately 0.5 inches. It is noted that the Battelle correlation results in a maximum allowable depth of 60% for all cracks longer than 1.6 inches.

As described in Reference 1, the determination of a maximum allowable crack depth requires consideration of crack length. Assuming 1.4 inches to be an expected limiting crack length for the next operating cycle, the Battelle correlation yields a maximum allowable crack depth of 61%, compared to 68% using the Framatome correlation. This translates into an operating cycle length of approximately 4.5 months is illustrated in Figure 3.

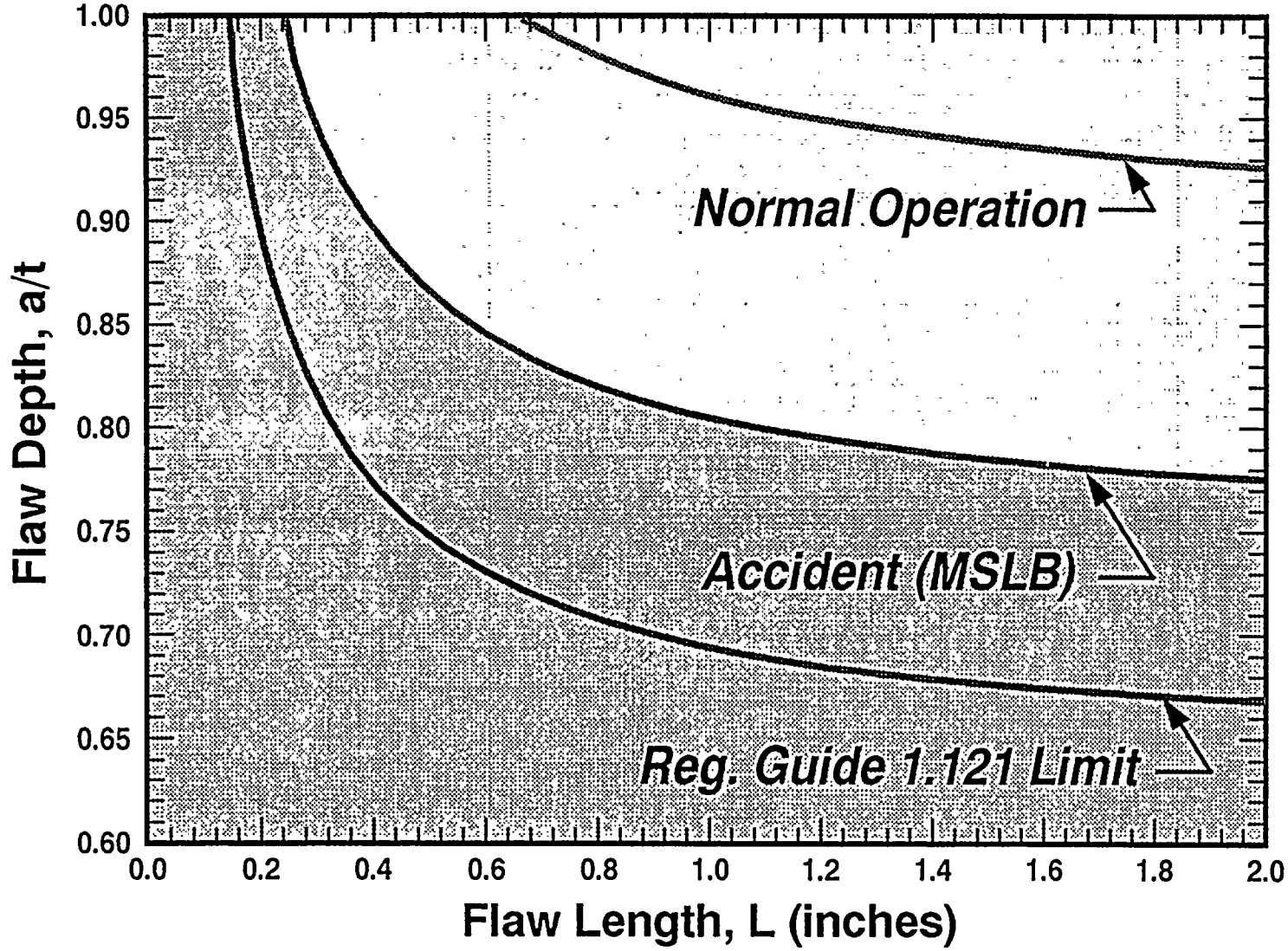
As was previously noted by APS in Section X.B of Reference 1, other correlations available in the industry literature would provide a more conservative prediction of burst pressure. The Framatome correlation was chosen to provide the best comparison with available burst test data. Figures 4 and 5 provide a comparison with burst test data using each of the two correlations. It is APS's judgement that the Framatome correlation provides the superior correlation. Figure 6 provides a comparison with the actual burst test results from the PVNGS Unit 2 pulled tubes using both correlations. Again the Framatome correlation provides the superior, yet sufficiently conservative comparison.

APS and its consultants had initially considered using the Battelle correlation, but found the correlation to be overly conservative for long cracks greater than approximately 0.75 inches. Data analysis of burst test results was performed to identify overly conservative trends. An example of the results of this data analysis is shown in Figure 7. This figure compares actual burst pressure versus predicted burst pressure, using the Battelle correlation, as a function of normalized crack length for crack depths between 50% and 60% throughwall. This comparison indicates that almost all cracks greater than normalized flaw length of 8 (which is equal to approximately 0.75 inches long actual length) burst well above the predicted pressure, while the actual burst pressure for shorter cracks was in much better agreement with prediction. It is for this reason that APS chose not to use the Battelle correlation since it resulted in overly conservative predictions for longer cracks.

While it is acknowledged that the Battelle correlation gives a more conservative result, it is APS's position that the Framatome correlation provides sufficient conservatism for use in the Regulatory Guide 1.121 evaluation. The Regulatory Guide requires large safety factors applied on the end result, therefore, additional conservatism on the predicted burst pressure is not warranted.

FIGURE 1

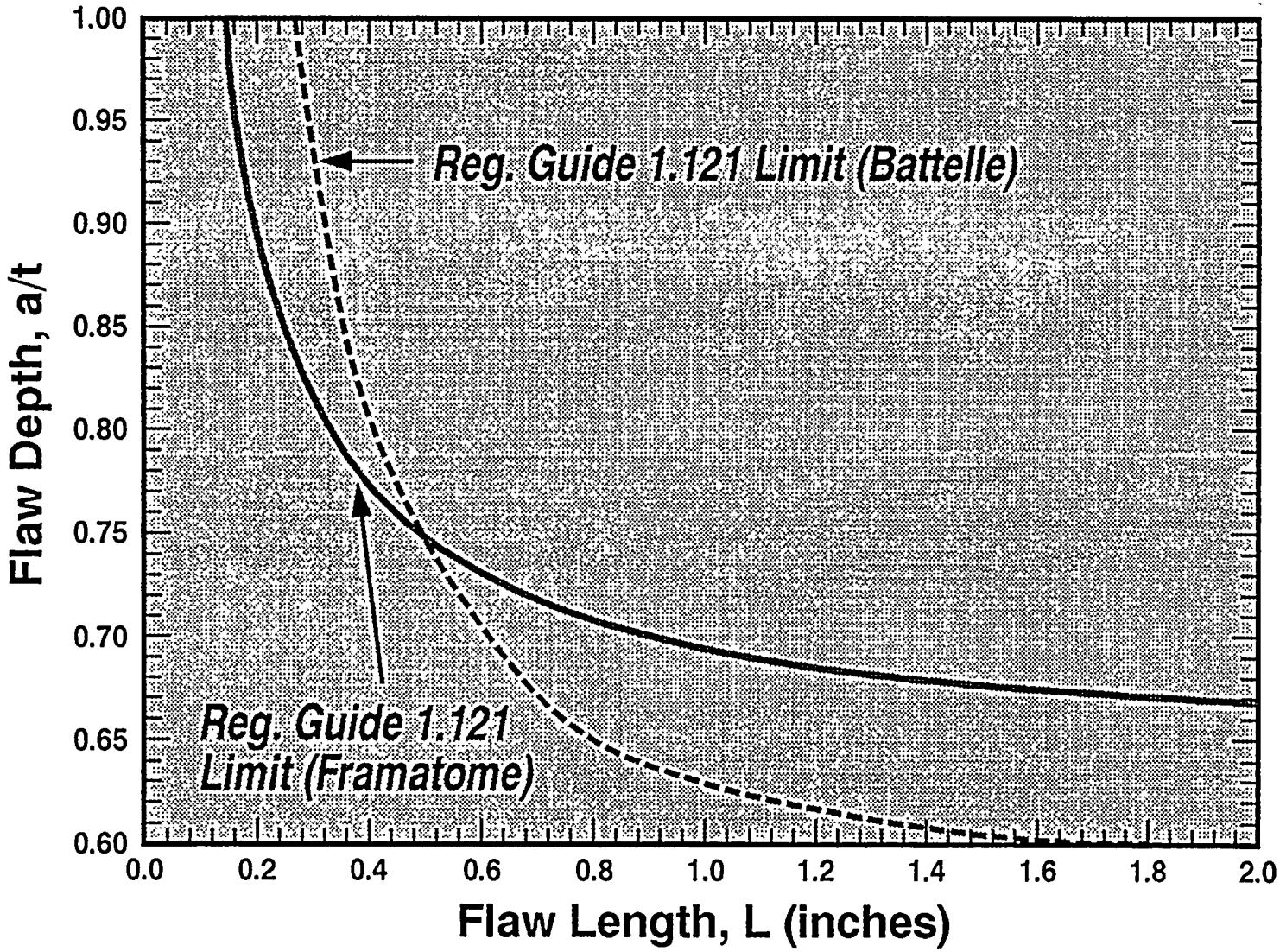
Axial Flaw Size Evaluation



7-23-93
AXIAL-1

FIGURE 2

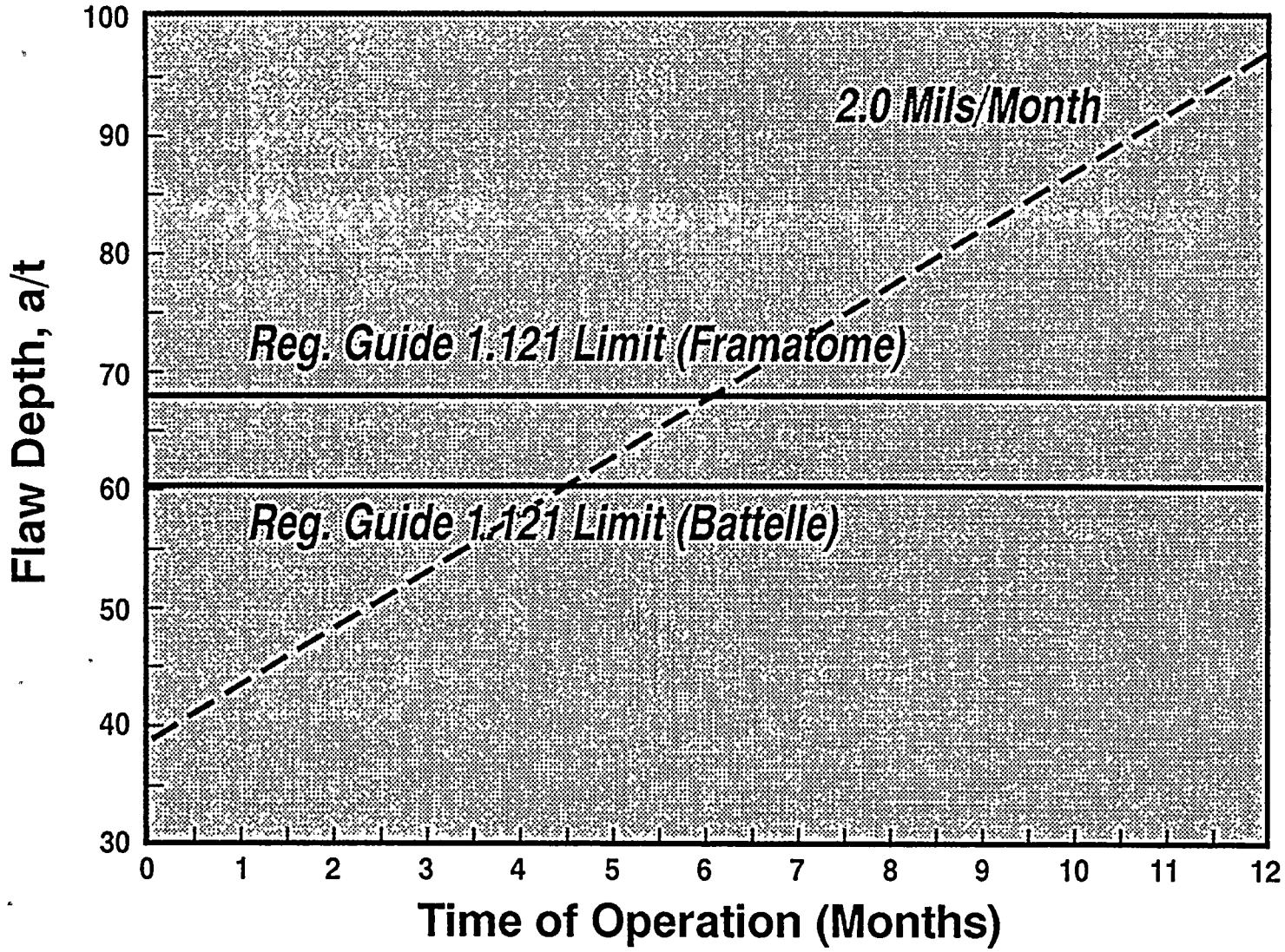
Axial Flaw Size Evaluation



7.28.93
FIGURE2

FIGURE 3

Operational Time Limits For Reg. Guide 1.12



7.28.93
AXIAL-2

FIGURE 4

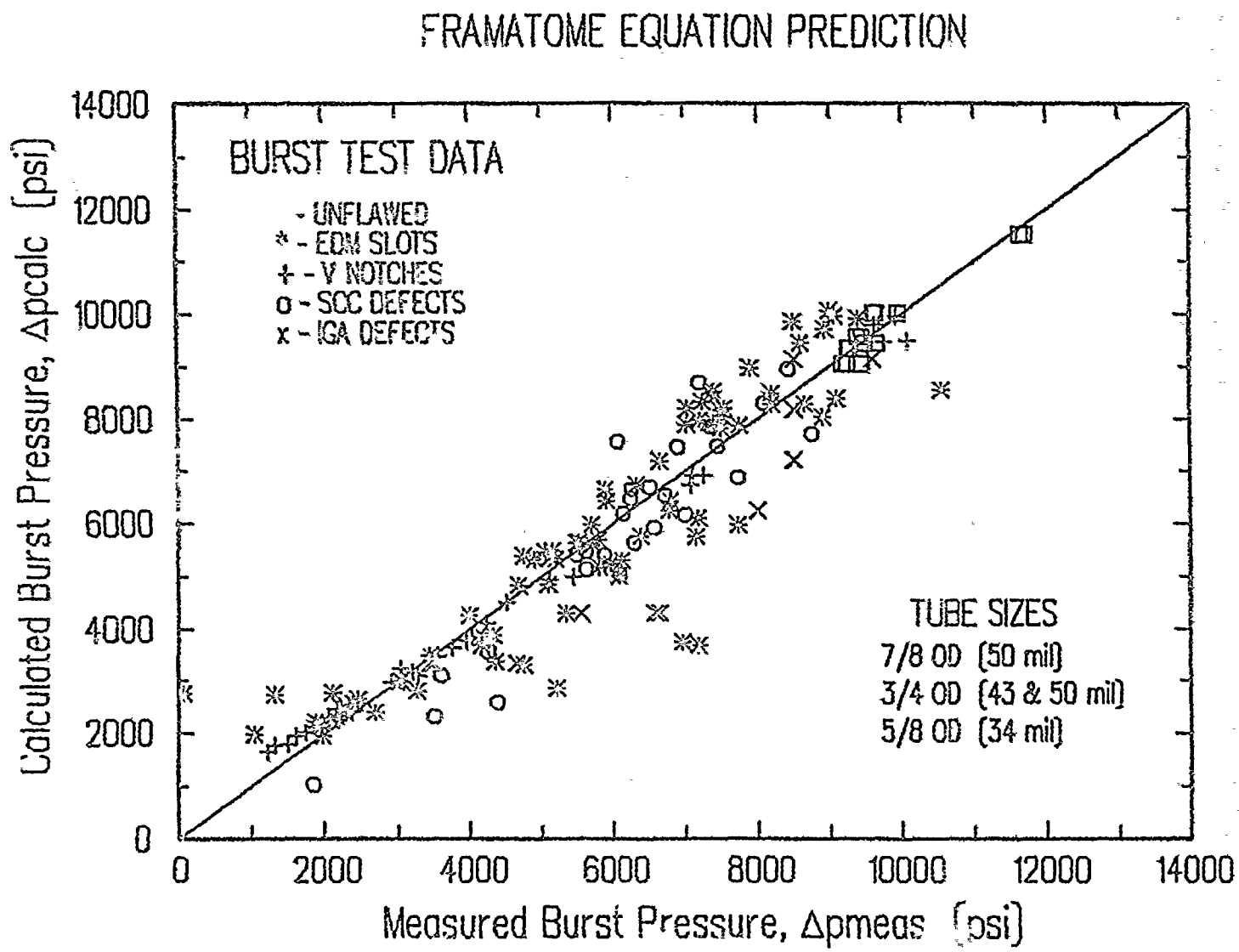

FRAMATOME EQUATION PREDICTION
BURST TEST DATA
- UNFLAWED
* - EDM SLOTS
+ - V NOTCHES
o - SCC DEFECTS
x - IGA DEFECTS
TUBE SIZES
7/8 OD (50 mil)
3/4 OD (43 & 50 mil)
5/8 OD (34 mil)
Calculated Burst Pressure, Δpcalc (psi)
Measured Burst Pressure, Δpmeas (psi)
0
2000
4000
6000
8000
10000
12000
14000

FIGURE 5

Battelle Equation Prediction

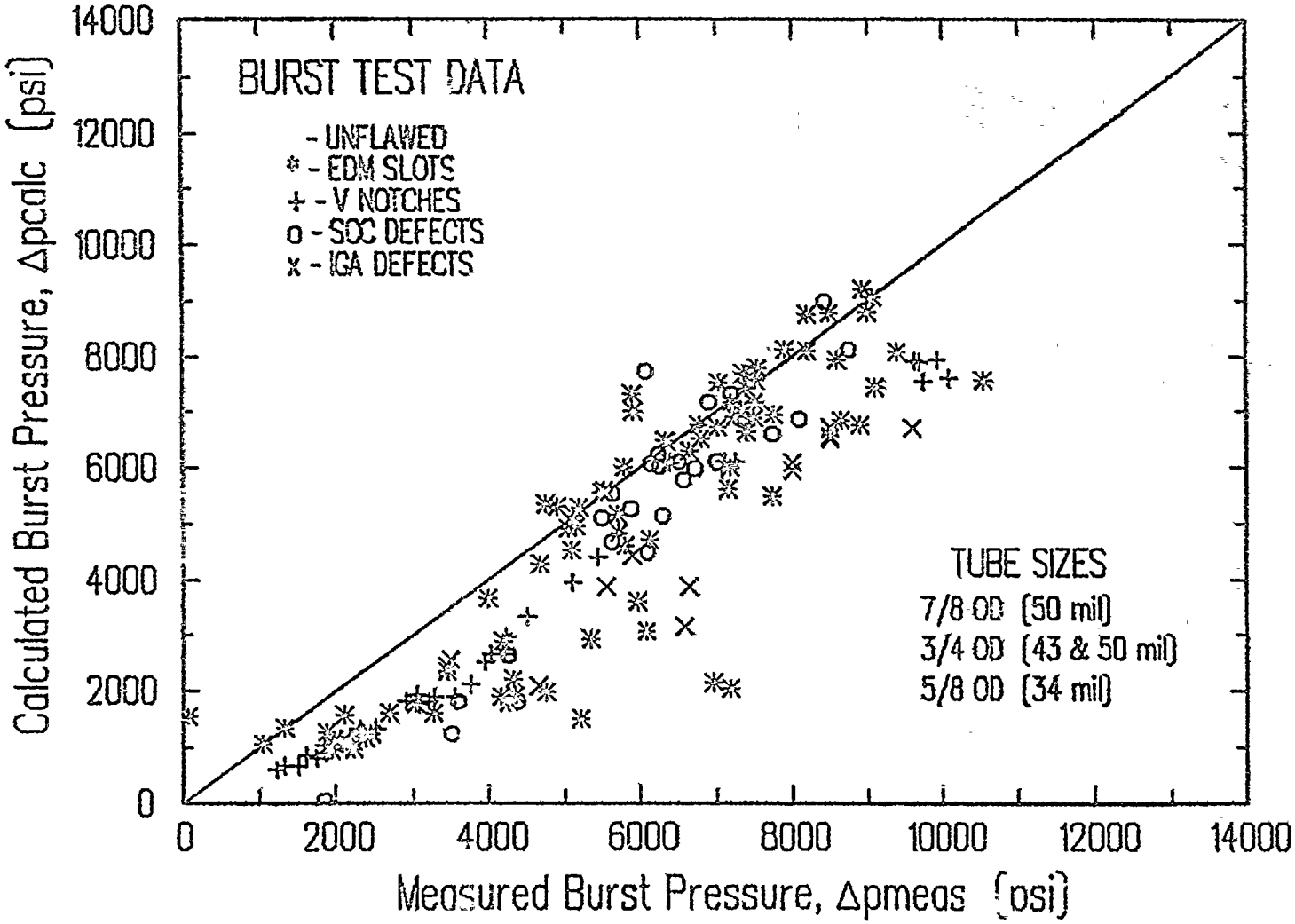


FIGURE 6

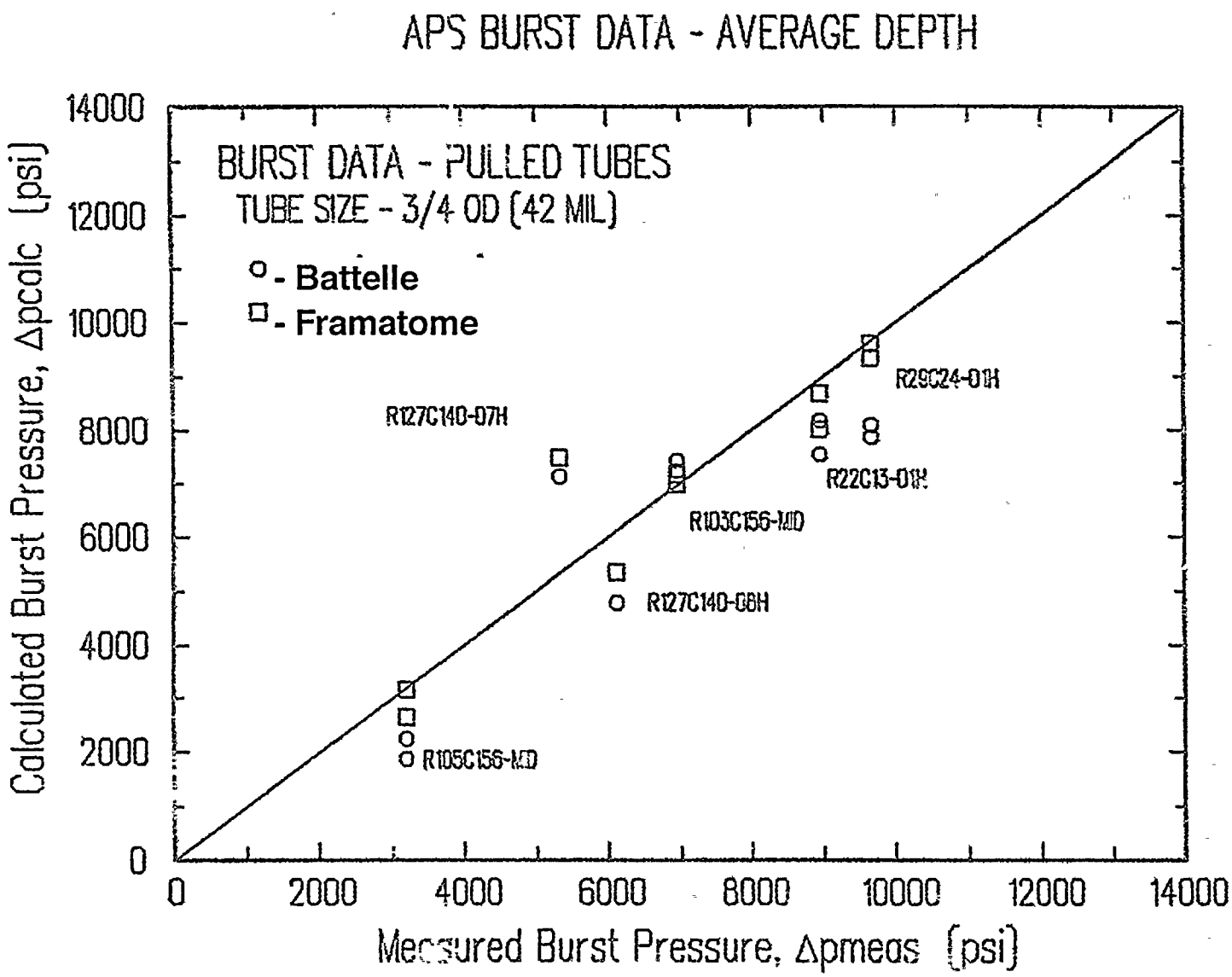
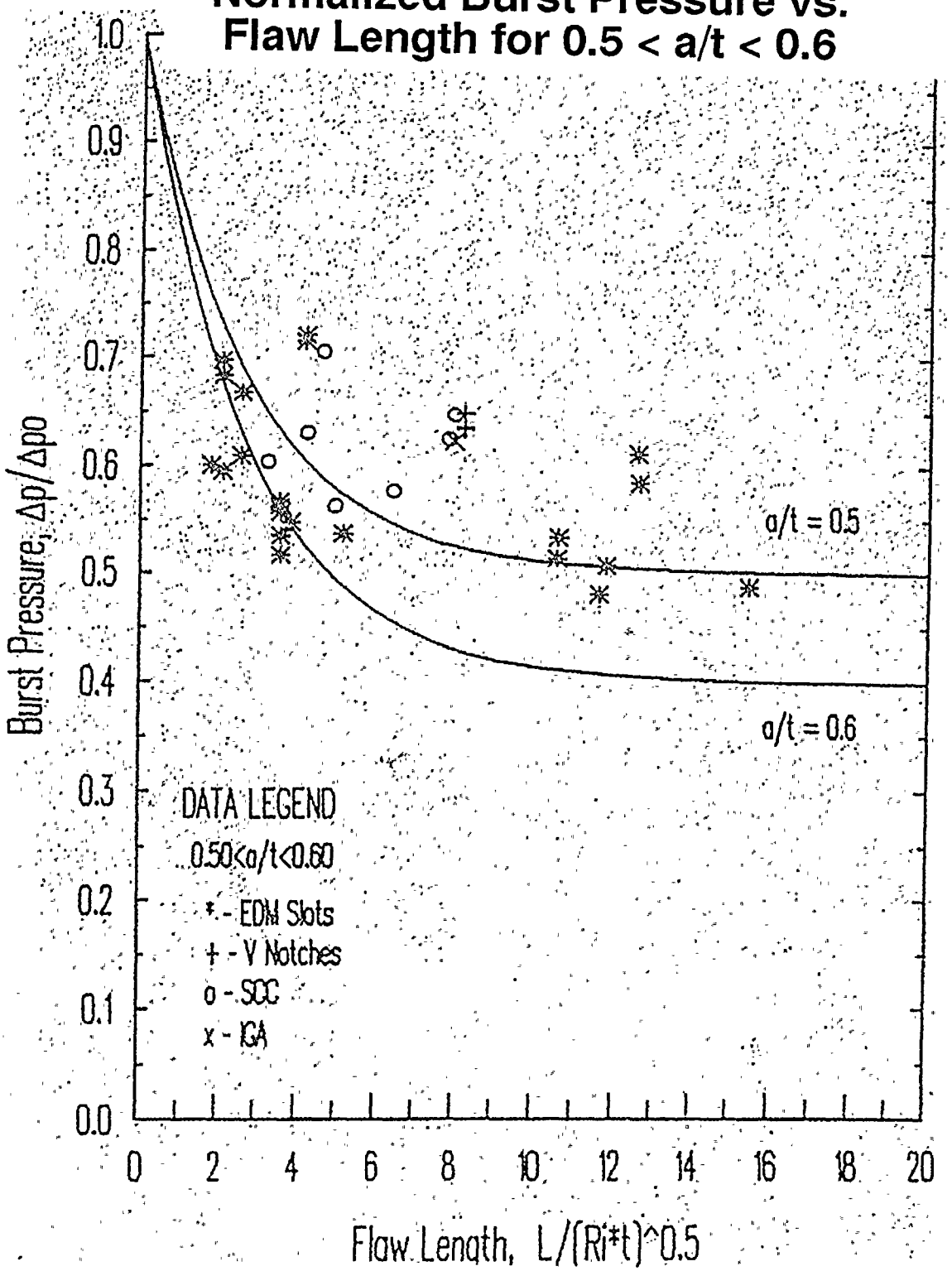

APS BURST DATA - AVERAGE DEPTH
BURST DATA - PULLED TUBES
TUBE SIZE - 3/4 OD (42 MIL)
- Battelle
- Framatome
R127C140-07H
R29C24-01H
R22C13-01H
R103C156-MD
R127C140-08H
R105C156-MD
Calculated Burst Pressure, Δpcalc (psi)
Measured Burst Pressure, Δpmeas (psi)
0
2000
4000
6000
8000
10000
12000
14000

FIGURE 7

Normalized Burst Pressure vs. Flaw Length for 0.5 < a/t < 0.6



Attachment 4

Additional Information Regarding Eddy Current Detectability of IGSCC

The NRC requested additional clarification regarding eddy current detectability threshold, which was used by APS in a Regulatory Guide 1.121 evaluation described in Section X of the Attachment to letter 102-02569-WFC/JRP dated July 18,1993 (Reference 1) and discussed in a meeting with NRC on July 26, 1993. Specifically NRC requested an explanation of the development of attached Figure 1, which was presented at the above referenced meeting.

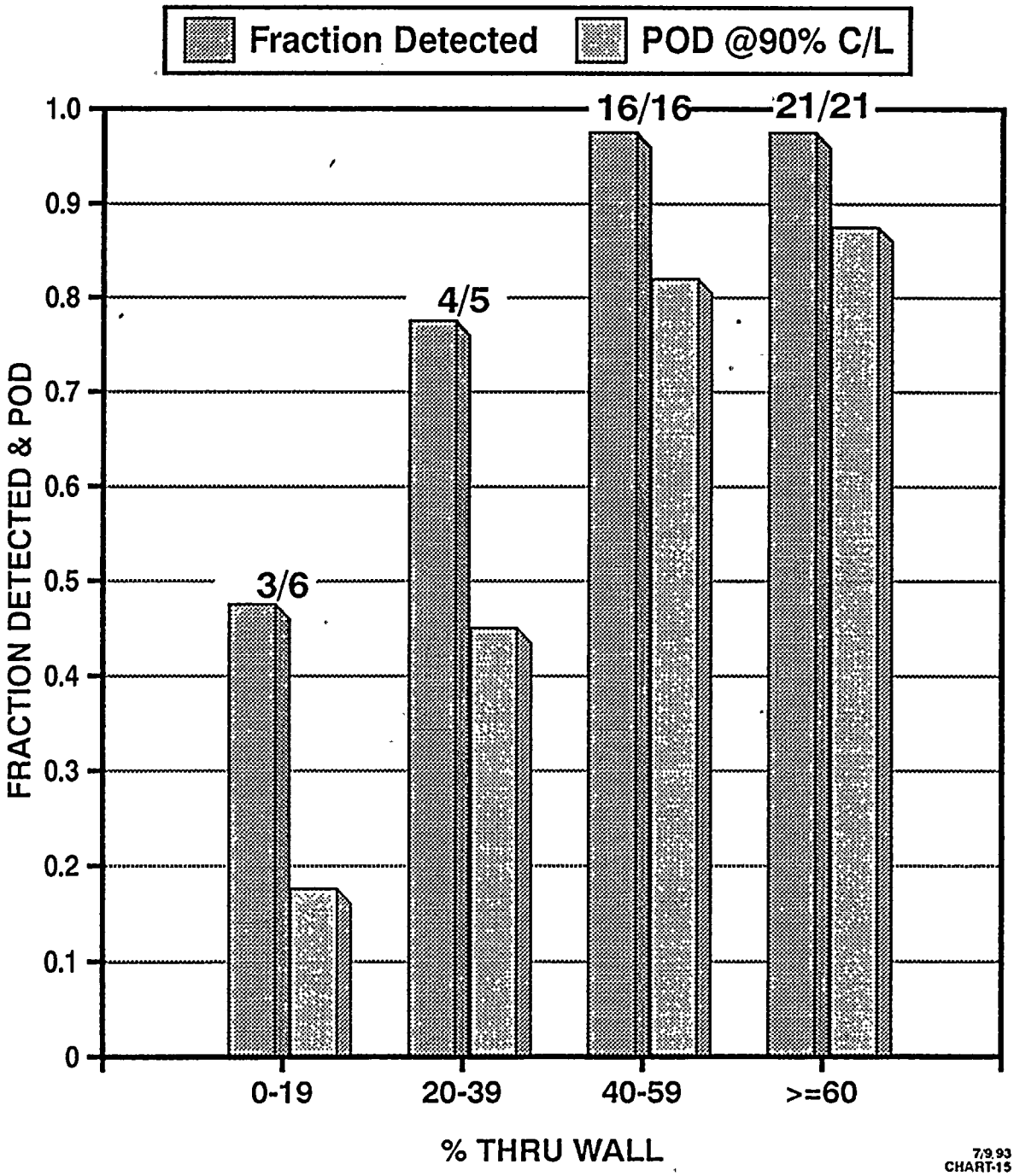
Figure 1 was presented as supporting evidence that general industry experience indicates reliable detection with bobbin coil of IGSCC cracks greater than 50% in depth. This graph was prepared by EPRI during eddy current technique (for detecting ODSCC) qualification. The graph was constructed using data from actual pulled tube samples and laboratory-induced stress corrosion cracking specimens. The pre-pull field eddy current data or the laboratory eddy current data was then reviewed by NDE Center eddy current analysts to determine if the technique being qualified produced detectable signals. The particular technique involves a differential mix of the prime channel frequency and 1/4 prime channel frequency. APS uses a 550/100 mix which is equivalent to a prime/one quarter prime mix. Therefore, although the data was used to qualify a technique, it does indicate whether a particular flaw produced a detectable signal. Accordingly, the data is representative of detectability capability. Note that this graph indicates a detectability threshold of 40%, while APS conservatively used a 50% bobbin coil threshold in its Regulatory Guide 1.121 evaluation.

In addition to the EPRI data, APS considered the results from pulled tube data at McGuire, ANO-1, and Beaver Valley. These results indicated a reliable detectability threshold of approximately 50%. Accordingly, 50% was considered to be representative of industry experience against which PVNGS Unit 2 pulled tube results were compared with. As described in Section VII.B.2 of Reference 1, the results from the Unit 2 pulled tubes are considered to be consistent with this industry experience.

FIGURE 1

TECHNIQUE QUALIFICATION

ODSCC Prime/QTR Diff Mix-Bobbin
Fraction Detected & POD @90% C/L



7/9/93
CHART-15

20