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SUBJECT: Response to NRC Staff Follow-Up Questions 1 through 4 from November 9, 2001 Meeting Regarding a TMI Unit 1 Steam Generator Severed Tube

On November 9, 2001 AmerGen made a presentation to the NRC regarding an event which resulted from a plugged tube in the "B" Once-Through Steam Generator (OTSG) that was discovered during the 1R14 refueling outage eddy current examinations to have severed and caused wear damage to adjacent tubes. This event was reported to the NRC in accordance with 10 CFR 50.72 on October 20, 2001. Enclosure 4 to the NRC's meeting summary dated November 21, 2001 was a list of 15 questions. In accordance with the meeting summary, the responses to questions 1 through 4 are enclosed as attachment 1.

Very truly yours,

MEWarner

Mark E. Warner
Vice President, TMI Unit 1

cc: H. J. Miller, USNRC, Regional Administrator, Region I
T. G. Colburn, USNRC, Senior Project Manager, TMI Unit 1
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File No. 01076

A001

Response to NRC Follow-Up Questions from November 9, 2001 Meeting Regarding the TMI Unit 1 Steam Generator Severed Tube

1. Please provide a montage of high magnification fractographs to augment the fracture surface map provided to the NRC staff on November 15, 2001 (which is attached as an addendum to the meeting handout in Enclosure 2). The fractographs should be annotated, including magnification and orientation, and should describe the significant features of the fracture surface. The fractographs should demonstrate examples of the features identified on the fracture surface map (e.g. IGA, fatigue striations, pueblo structure, flowed metal, ductile tearing and smeared metal). Provide a discussion of the fracture surface features as they relate to the postulated failure sequence of events, i.e., outer diameter (OD) IGA as points of origin for fatigue propagated by flow induced vibration, followed by ductile tearing.

Response

A low-magnification Scanning Electron Microscopy (SEM) mosaic of the entire fracture surface is shown in Figure 1. As can be seen in Figure 1, much of the fracture surface was smeared, or burnished, by the rubbing of the fracture surfaces against each other during the failure process. After the tube separated, additional fracture surface was lost by abrasion when the tube rubbed against the adjacent tubes. Nevertheless, it was possible to identify several regions of OD intergranular attack (ODIGA), fatigue damage, and ductile tearing. These regions of interest are identified in Figure 1. In the discussion that follows, reference is made to several SEM fractographs to illustrate the regions of specific damage. In all of the fractographs presented, the vertical orientation of the images is preserved with respect to Figure 1; i.e., the 0° reference is toward the bottom of the figure, and the 180° reference is toward the top of the figure. Rotational orientation is counterclockwise from the 0° reference.

Figure 2 is an SEM mosaic of a portion of the fracture surface from ~ 45° to 135°. In this region of the fracture surface, intermittent regions of ODIGA ranging from 10 to 13% through wall were observed. A typical area of smeared, or burnished, metal can also be seen in Figure 3a. All of the areas of smeared metal are nearly featureless.

Figure 3b is a higher magnification image of Area 1 in Figure 3a, showing the ODIGA more clearly. It is postulated that this IGA was present prior to the hydraulic swelling that was experienced, as is typical for OTSG tubing in the steam space of the steam generator. The grains and adjacent fracture surface were also covered with deposited material, primarily aluminum, silicon, magnesium, and titanium. No species, such as chloride, sulfur or lead, which are known to be detrimental to Inconel 600, were detected.

Figure 3b also shows very clearly the transition from classical IGA to a blocky, faceted surface (previously described as a pueblo structure), features that are

typically associated with Stage I fatigue. In addition to a crystallographic fracture topography, another characteristic of Stage 1 fatigue is the presence of a smooth or burnished surface caused by rubbing of the bottom and top of the crack. Such rubbing would account for the areas of smeared metal mentioned earlier.

A similar transition from IGA to Stage I fatigue can be seen in Figures 4a – c, from an area of the fracture surface at ~100 degrees. These observations are strong evidence that fatigue cracking initiated from regions of ODIGA where the stress intensity was at or near the threshold stress intensity factor. This initial fatigue crack was propagated initially by a high cycle, low stress fatigue mechanism. The rate of propagation during this stage of fatigue is not known, but is typically slow as compared to Stage II fatigue. The full circumferential extent of Stage I fatigue is also not known due to the extensive mechanical damage experienced; however, it is likely that the regions of smeared metal were also Stage I fatigue.

As can be seen in Figures 4a and 5a, the appearance of the fracture surface changes at approximately mid-wall from the granular, faceted surface characteristic of Stage I fatigue to a rippled, clamshell surface typical of Stage II fatigue. A higher magnification image of this area is shown in Figure 5b. Within these clamshell areas, or beachmarks, are numerous fatigue striations spaced on the order of 1.7 – 2.4 microns apart. These features are typical of Stage II fatigue, where each striation represents a step advance in the crack front under the influence of alternating and increasing tensile stress. As indicated in Figure 5b, the direction of crack propagation was radially inward toward the ID. The reduced cross sectional area of the tubing would have caused the increase in applied stress as the crack grew during the initial Stage I fatigue. The rate of propagation in this regime of fatigue would be quite rapid, progressing to the ID in seconds.

The ultimate failure that resulted in separation of the tube was by tensile overload of remaining ligaments as the tensile strength was exceeded. Two clear areas of ductile failure were observed on the fracture surface between ~270 to 360 degrees (Figure 6). One of these regions was located adjacent to ODIGA at ~250 – 270 degrees, as shown in Figure 6a. The dimensions of this ductile area were 1 mm x 0.2 mm. The most prominent observable ductile region occurred from essentially the tube OD to the tube midwall from ~330 to 360 degrees. This area is shown in Figure 6b. Smeared metal obscured the area between the midwall and the tube ID.

All of the observations described above support the failure scenario that has been proposed:

- The tube first expanded hydraulically, creating an expansion transition at the tubesheet secondary face and at the 15th tube support plate.
- This expansion created residual tensile stresses at the expansion, increased the tubing mechanical strength through plastic deformation, and opened existing intergranular penetrations.

- Cyclic bending stresses at the tube-to-tubesheet interface created by reduced stability, due to the restrained lateral movement at the 15th tube support plate, and flow-induced turbulence concentrated at the tips of the intergranular penetrations (ODIGA), initiated Stage I fatigue cracking.
- This cracking progressed to approximately mid-wall, during which time the applied tensile stress increased due to reduced cross-sectional area.
- At approximately mid-wall, the crack progressed to Stage II fatigue, a much more rapid and cohesive process, leading to throughwall propagation in seconds.
- Final separation of the tube occurred by tensile overload of the remaining ligaments.

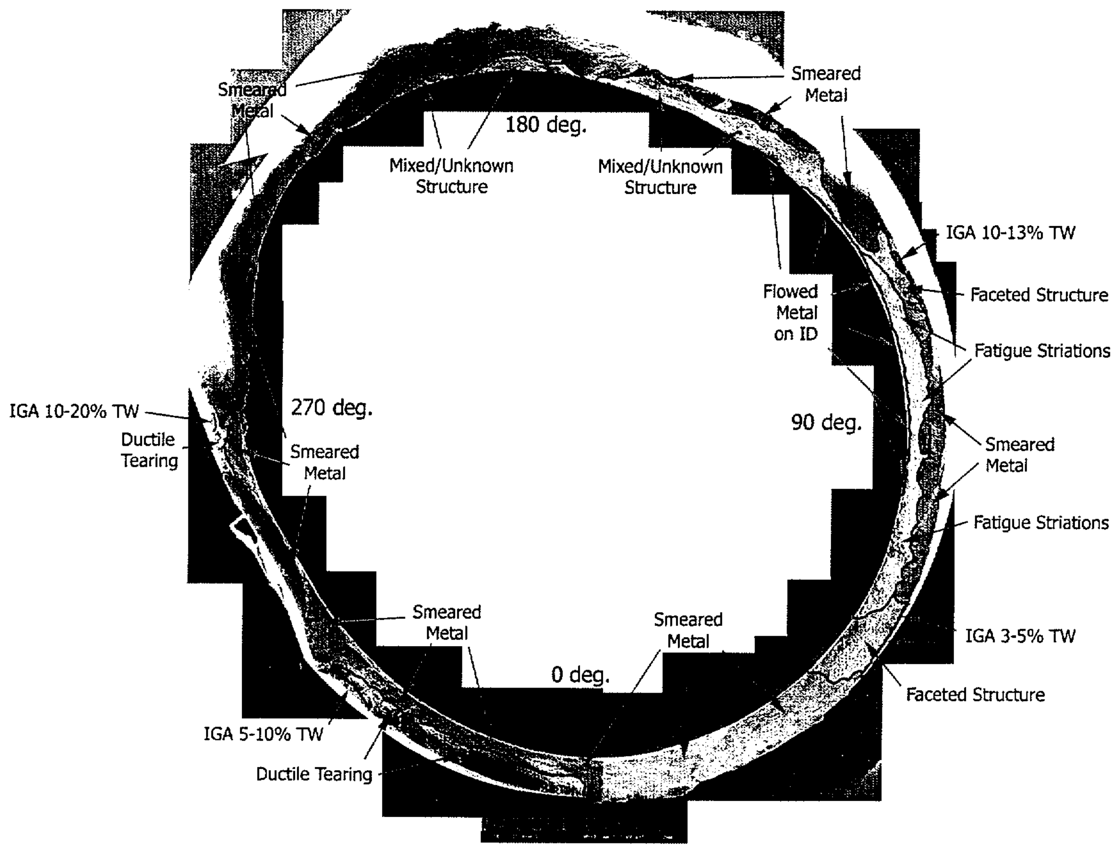

Figure 1. SEM mosaic of fracture face of TMI-1 tube no. B66-130

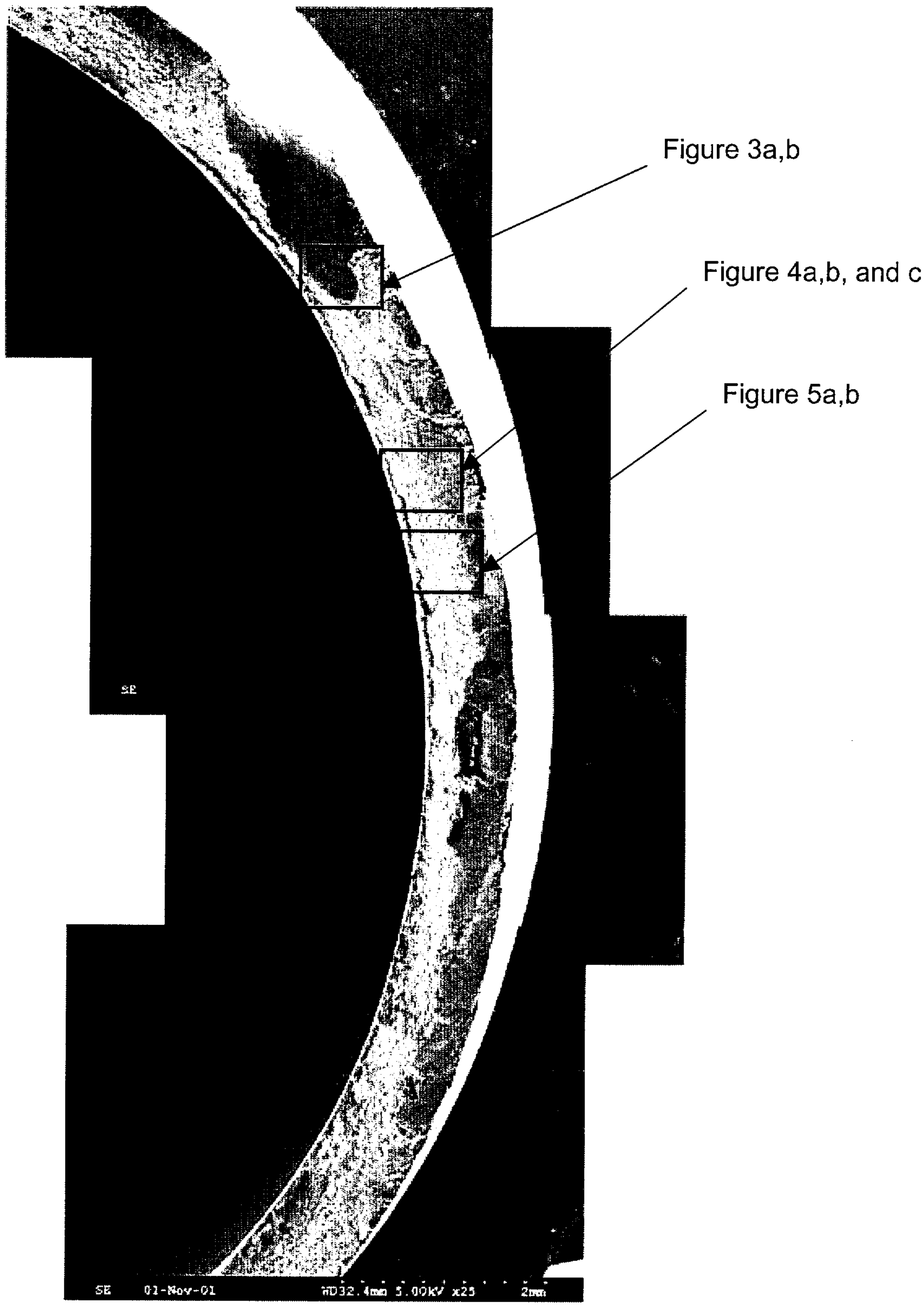

Figure 2. SEM mosaic of fracture surface from ~45 to 135 degrees

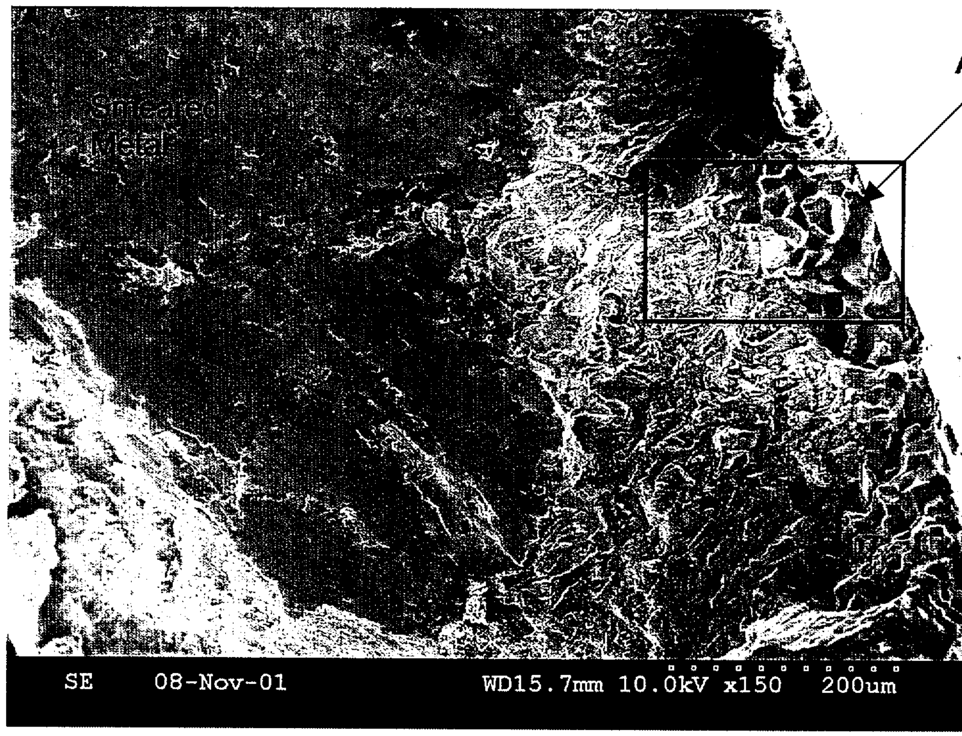

Figure 3a. Fracture surface at ~120 degrees, showing ODIGA, Stage I fatigue, and a region of smeared, or burnished, metal (150X)

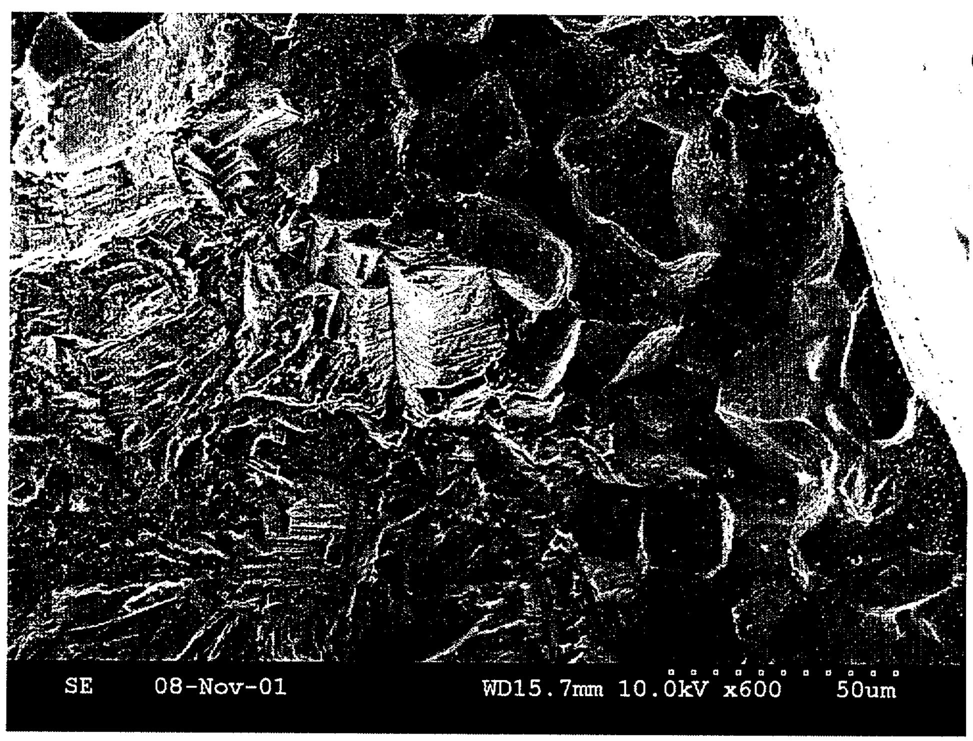

Figure 3b. Area 1 in Figure 3a, showing transition from ODIGA to Stage I fatigue (600X)

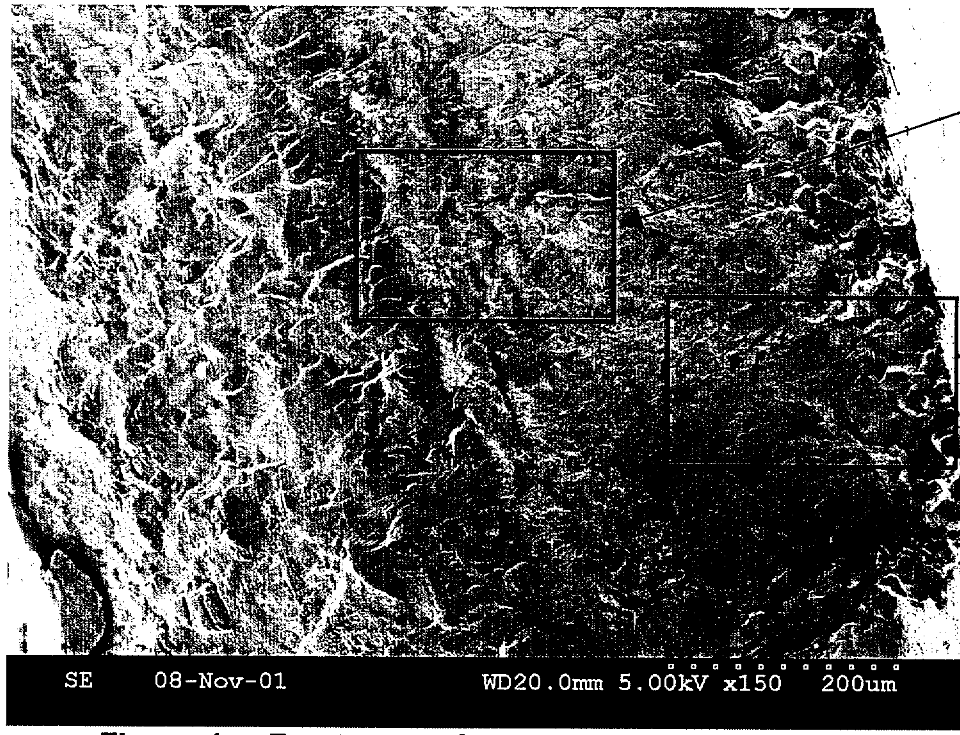

Figure 4a. Fracture surface at ~100 degrees (150X)

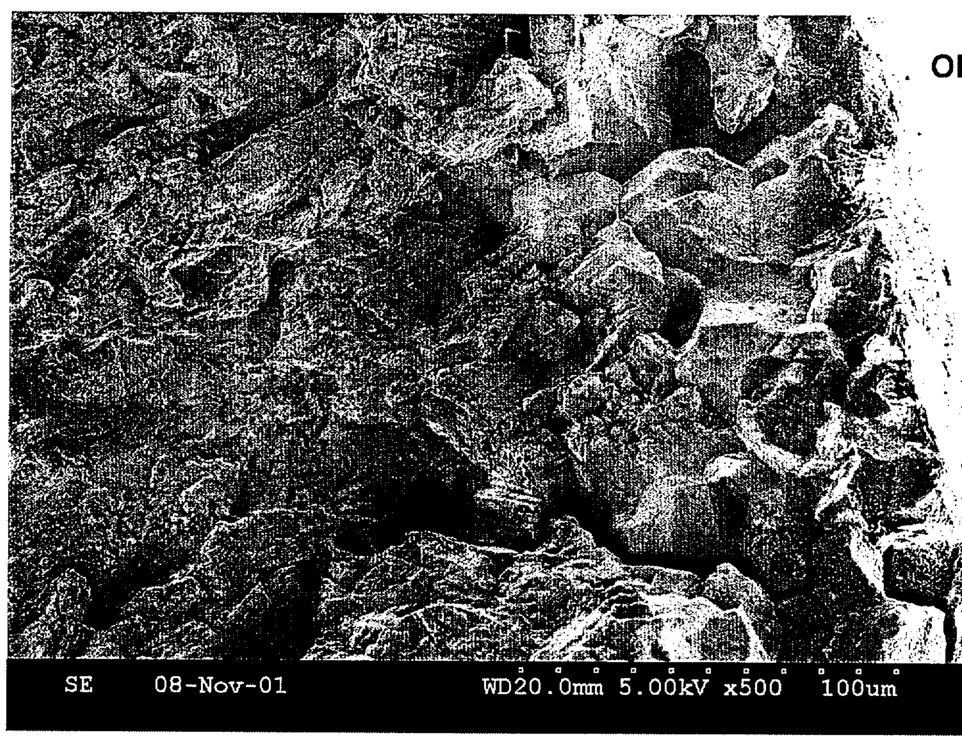

Figure 4b. Area 1 in Figure 4a, showing transition from ODIGA to Stage I fatigue (500X)

OD →

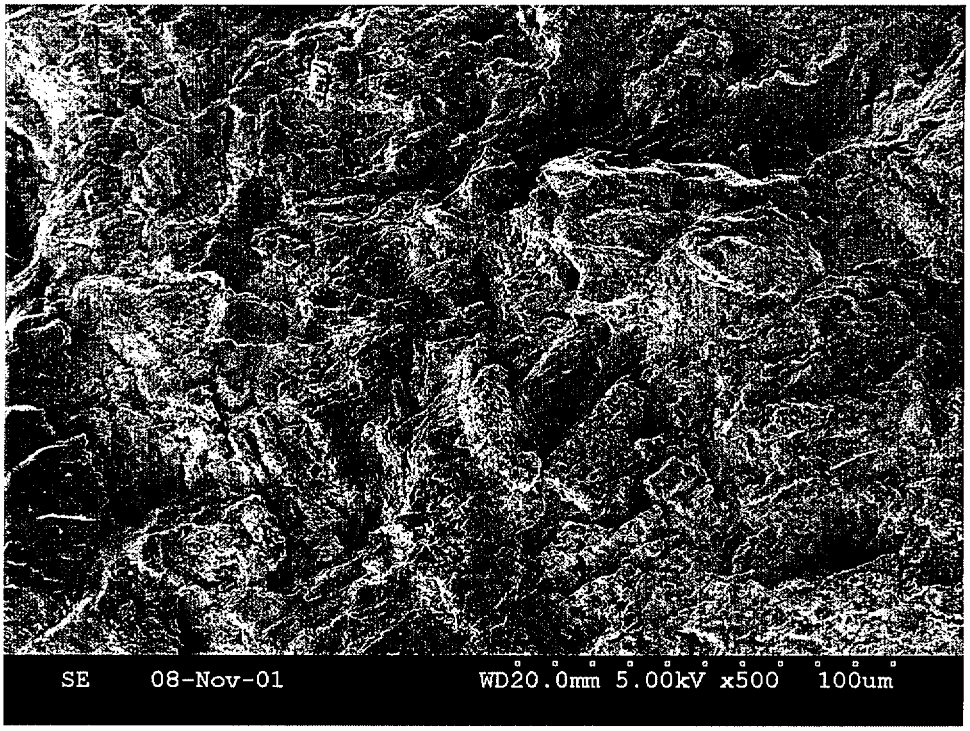

Figure 4c. Area 2 in Figure 4a, showing features of Stage I fatigue (500X)

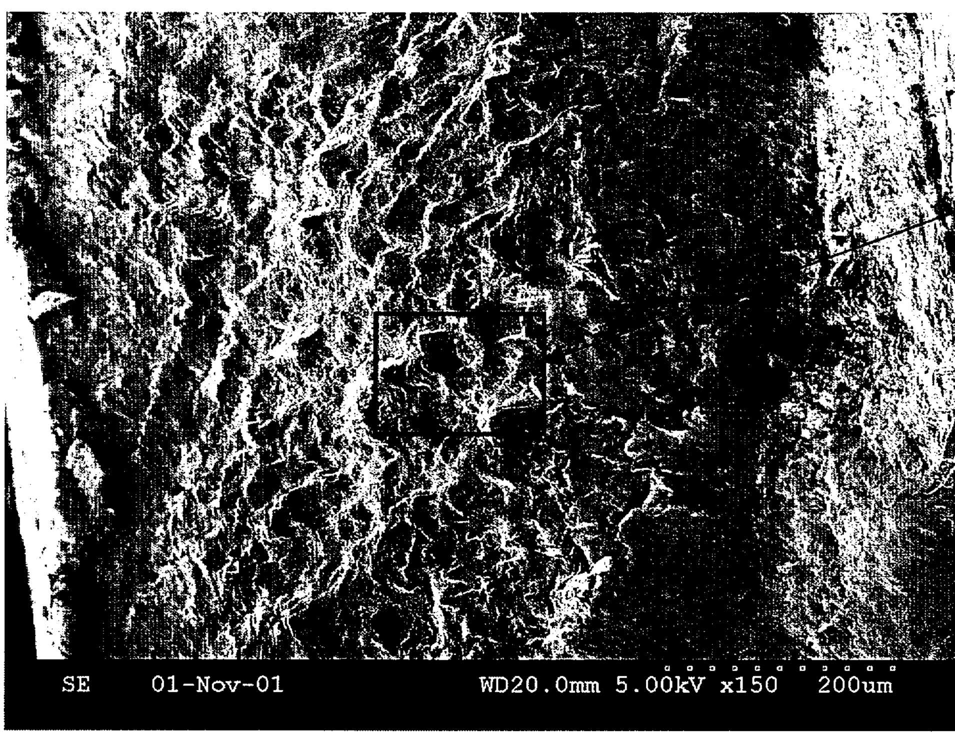

Figure 5a. Fracture surface at ~95 degrees, showing change in fatigue propagation from Stage I to Stage II (150X)

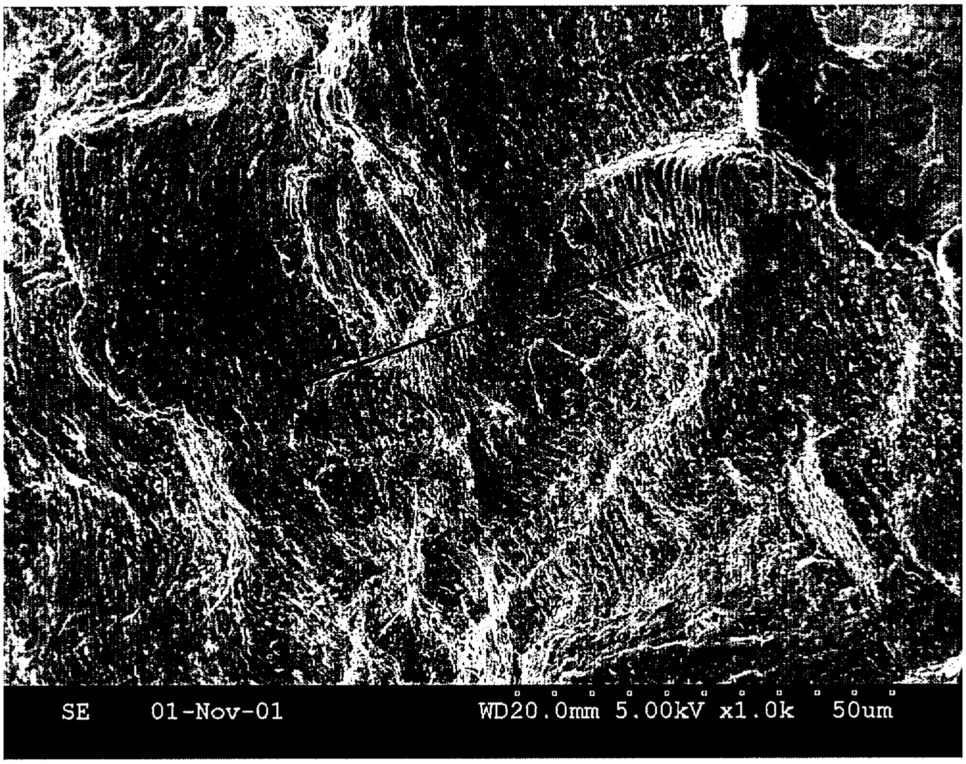

Figure 5b. Area 1 in Figure 5a showing Stage II fatigue striations (1000X). The arrow indicates the direction of fatigue crack propagation.

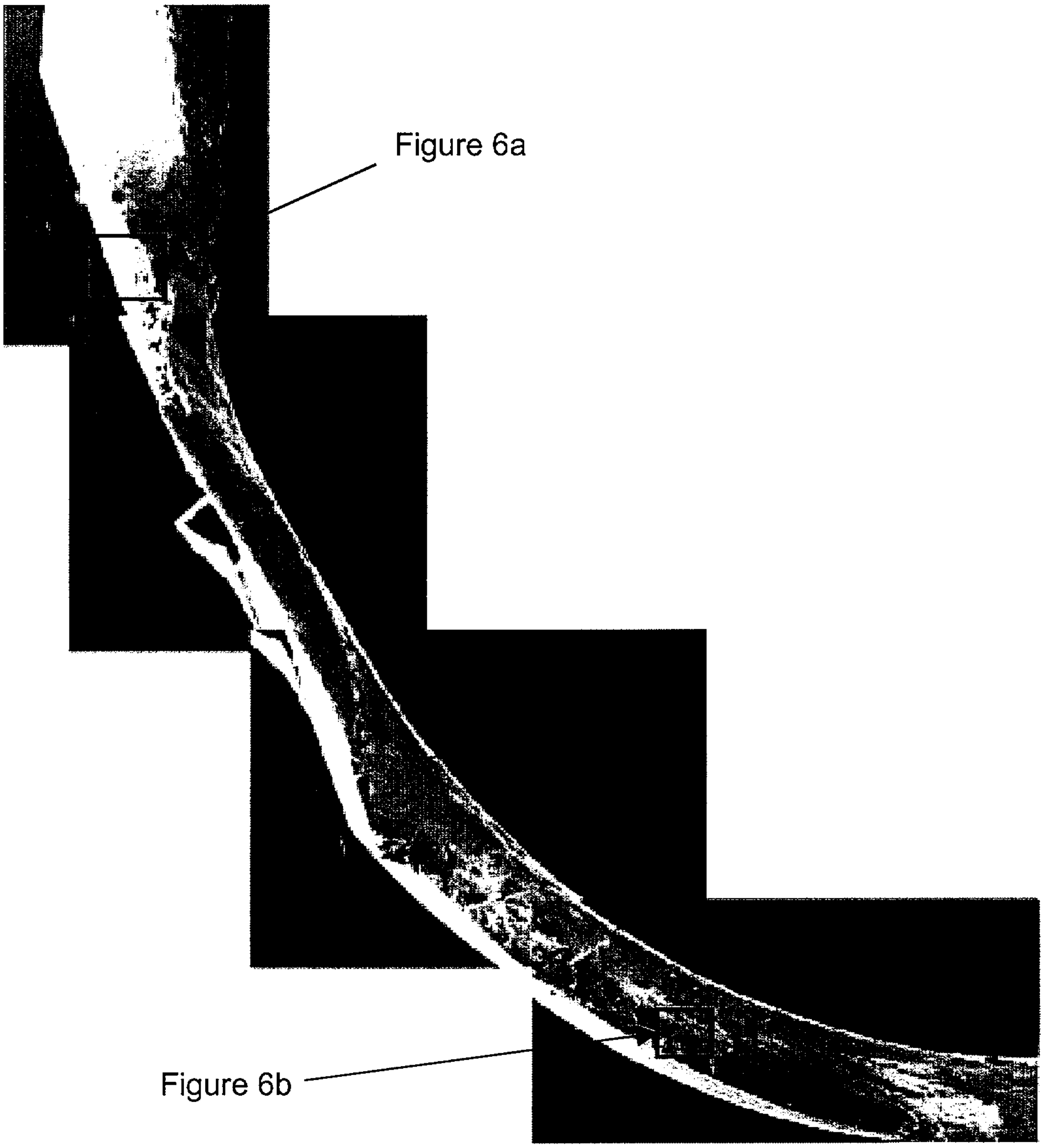

Figure 6. SEM mosaic of fracture surface from ~270 to 360 degrees

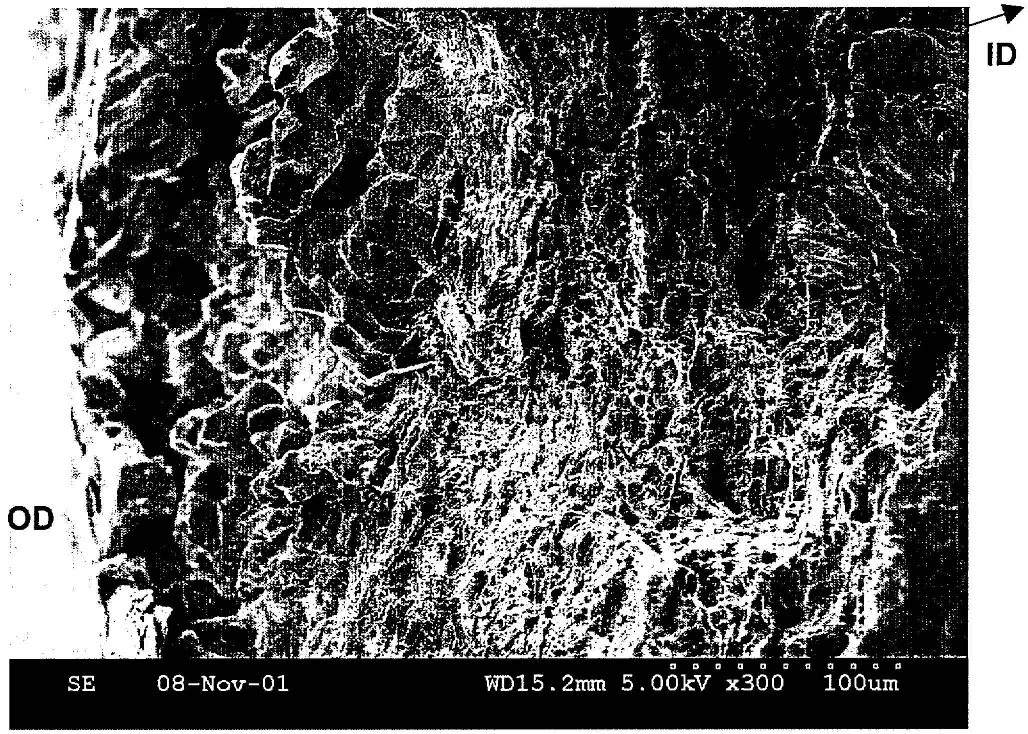

Figure 6a. Region of ODIGA (~20% TW) and adjacent area of ductile tear 300X)

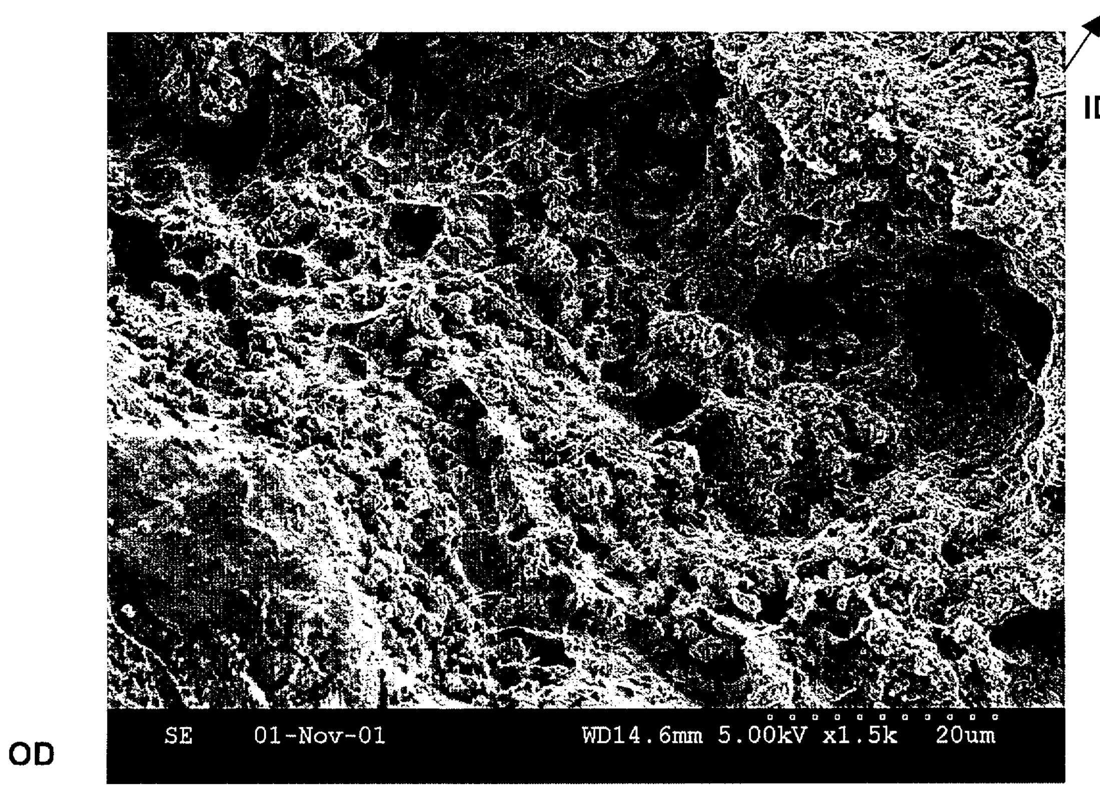

Figure 6b. Region of ductile failure at ~330 degrees (1500X)

2. Summarize the results of the metallography, hardness measurements, and mechanical testing that have been completed on the severed tube and other harvested tubes. Describe the locations of the test specimens (or hardness tests) relative to the fracture surface location. Relate these results to the postulated failure mechanism.

Response

All laboratory results are preliminary pending issuance of the final laboratory report. Any Changes to these values will be communicated to the NRC staff.

Tensile Test Data

Tensile tests were performed at ambient temperature in accordance with ASTM E 8, "Tension Testing of Metallic Materials," on sections of tubing removed from OTSG B tubes 65-130, 66-130 and 66-131. All three tensile specimens were from sections of tubing ~ 40 inches below the upper tube sheet secondary face (i.e., fracture location). The base material tensile properties for these three tubes are tabulated below:

Table 1

Base Material Mechanical Properties

Property	65-130	66-130	66-131	CMTR Data
Tensile Strength (psi)	99,435	113,783	98,858	99,785
Yield Strength (psi)	48,494	85,185	47,900	48,190
% Reduction of Area	29.9	27.7	38.8	-
OD, inches	0.626	0.699	0.626	0.625

All three tubes were fabricated by Pacific Tube Company per ASME SB-163 and Section III of the ASME Code. The material heat for all three tubes is M2868. The Certified Material Test Report (CMTR) ultimate tensile and yield strengths for this heat of tubing are also shown in the table. Tube 66-130, which is the severed tube, exhibited an increase in diameter to 0.699 inches from the nominal 0.625 inches, shows a slight increase in tensile strength and a significant increase in yield strength as compared to both the CMTR values and to the unexpanded tubes. These changes would be as expected for a tube that has undergone significant plastic deformation resulting from the hydraulic expansion caused by overpressurization.

The mechanical properties for tubes 65-130 and 66-131 are from sections removed from undamaged regions of these adjacent tubes and compare closely with the CMTR values.

Micro Hardness Data

Vickers microhardness readings were taken on mounted samples from all three tubes to determine the material hardness. All samples were located ~12 inches below the secondary face of the upper tube sheet, except one that was taken at the wear scar. Readings were taken at two rotational orientations in the baseline samples at the tube ID, midwall, and OD. Each value in the table below is an average of 6 measurements.

Table 2

Micro-Hardness Measurements
(Vickers-500gm)

Tube Wall Location	**65-130**	**66-130**	**66-131**
ID	184.6	271.9	180.9
Mid Wall	172.8	249.3	172.6
OD	185.6	261.6	187.8
Wear Scar	236.7	273.1	213.4

Note: Readings for ID, mid-wall and OD were taken away from any wear scar. Wear Scar readings were taken at the OD surface in the deformed grains.

As expected the hardness of tube 66-130 is higher as a result of the cold work from being hydraulically expanded, as are the readings taken in the vicinity of the wear scars.

Hydraulic Swell Test

A sample of tubing removed from approximately 13 – 27 inches below the upper tube sheet face, tube 65-130, was hydraulically swelled approximately 8.6% from 0.626 to 0.680 inches OD at a pressure of 9,784 psi. A photomicrograph of the expanded portion of the tube shows shallow ODIGA 1-2 grains deep (Figure 1). This is typical for tubing in the steam space of B&W OTSGs. No other microstructural anomalies were observed and the microstructure is typical of sensitized Alloy 600 tubing, with carbide decoration of the grain boundaries.

Microstructural Observations of Interest

The following observations were made, based on the metallography performed on transverse sections located approximately 12 inches below the fracture surface.

- ODIGA on the non-severed tubes was typical for OTSG tubing in the steam space and was approximately 1-2 grains deep, as described above.
- ODIGA of the severed tube was also 1-2 grains deep with an occasional penetration to 3-4 grains deep (Figure 2). As can be seen in Figure 2, some "twinning" of grains occurred as a result of plastic deformation caused by the over-pressurization event. Such twinning can occur during a high rate of stress loading and increases the resistance of the material to further plastic deformation.
- The microstructure at the OD in the vicinity of the wear marks on tube 66-130 was highly deformed and typical of severe cold work that would be expected from rubbing by an adjacent tube. It extended only a few grains deep from the OD surface. ODIGA was not present in the vicinity of the wear scars suggesting that any ODIGA would have been removed as part of the wear process. As expected, ODIGA was observed between the wear scars.

The preceding results demonstrate that the mechanical properties for tube 66-130 were significantly altered from the as-fabricated tubing properties as a result of the overpressurization and swelling. The ODIGA in both tubes 65-130 and 66-130 supports the hypothesis that the IGA observed in the severed tube was preexisting and may have contributed to the failure mechanism. All of the results support the failure scenario as described in the response to Question 1.

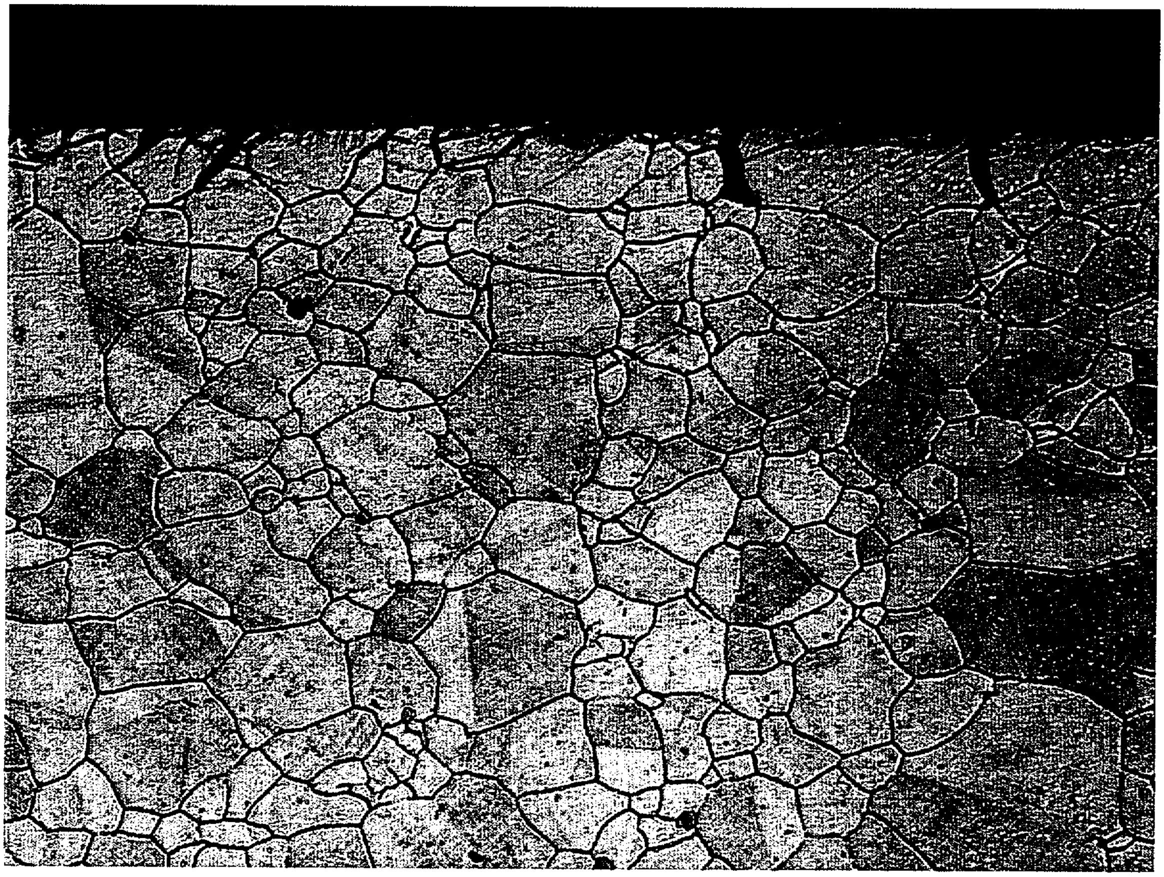

Figure 1. Etched cross-section of expanded section of tube no. 65-130 showing the presence of ODIGA (500X)

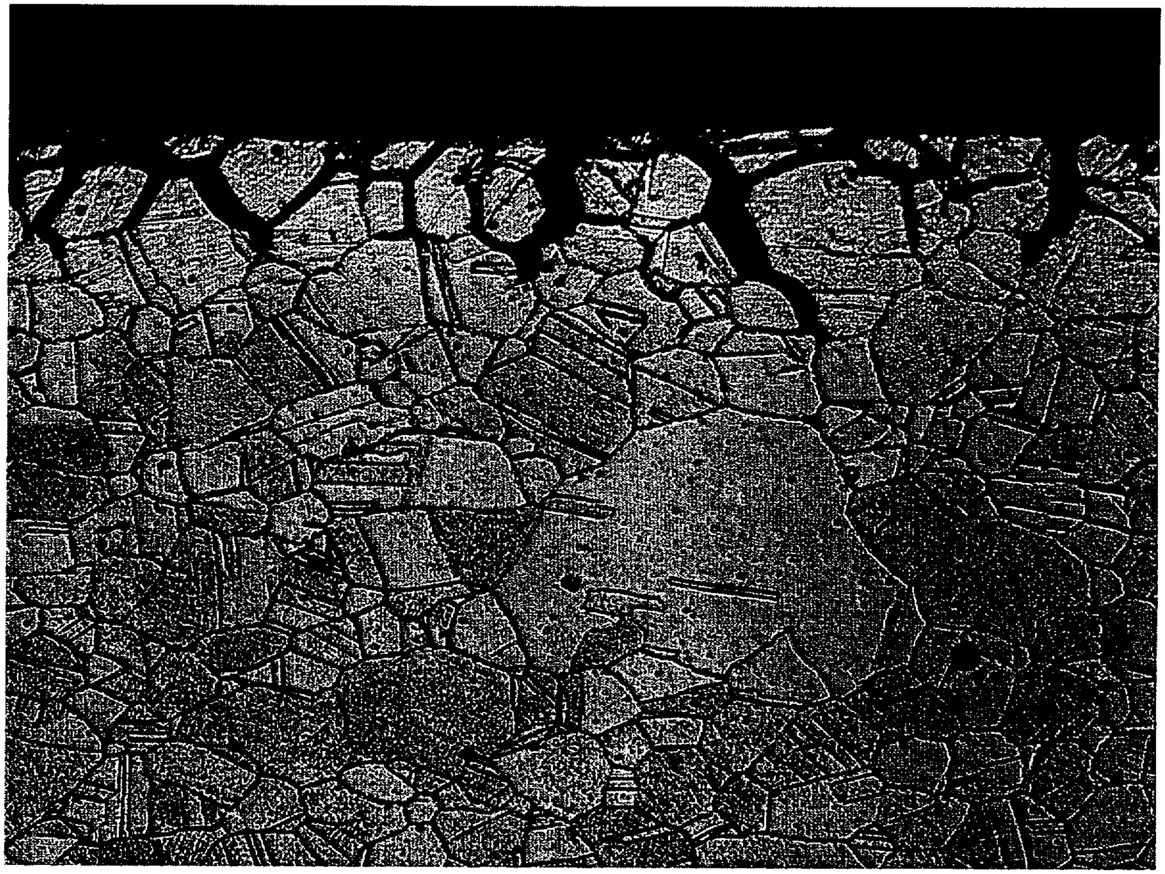

Figure 2. Etched cross-section of severed tube no. 66-130 showing grain twinning and the presence of ODIGA (500X).

3. <u>What alternating stress level is suggested by the striations at the various stages of fatigue crack development? What was the number of alternating stress cycles to failure</u>?

<u>Response</u>:
An action to confirm FIV loading using striations on the fracture surface of tube B66-130 was initiated as part of the TMI 1R14 Steam Generator Project. This work could provide a validation of the predictive capability of the FRA-ANP analysis model from both the fluid dynamics and structural mechanics perspectives.

The assessment of the feasibility of this analysis focused on whether there was credible data to supply the information that is necessary to produce quantifiable results. The axial plastic strain at the elevation of the fracture and multiple initiation sites on the fracture surface were considered with respect to fracture mechanics requirements.

The axial plastic strain due to swelling is estimated to be about 5-7%. This indicates that a high mean stress condition existed concurrently with FIV alternating bending stress. As a result of strain hardening, the nominal tensile properties have also changed. The available correlation of crack propagation to applied stress intensity is derived using specimens that do not have an elevated strain component.

Multiple initiation sites, which are apparent on the fracture surface, make it difficult to establish an applied stress intensity factor to analyze stress/flaw interaction. There is a small amount of clear features on the fracture face of a small specimen. The total amount of fatigue damage, either as additional initiation sites or additional striations, can not be determined.

The major bending axis due to FIV may not contain the initiating flaw. Also, postulated fatigue propagation in both the radial and circumferential directions could indicate that there is no preferential bending direction, i.e., orbiting, so that quantification of bending stress may not be possible.

Analytical confirmation of FIV loading using striations on the fracture surface can not be accomplished in a meaningful way. The fracture mechanics analysis requirements can not be satisfied due to limitations in information relating crack growth to applied stress intensity at high mean strain, limited information on the fracture face, as well as uncertainties regarding multiple initiation sites and quantification of nominal bending stress.

4. Discuss your plans for stabilization of swelled tubes (i.e., full length stabilization) and the purpose of these actions.

Response:
With the exception of B66-130 and B150-14, as discussed below, the tubes that were found to be swollen by the eddy current inspection of de-plugged tubes were stabilized with full length stabilizers. The stabilizers extend from the upper tubesheet plug to approximately 8 inches below the lower tubesheet secondary face. Full length stabilization of swollen tubes is a conservative measure to mitigate the effects of potential tube degradation as a result of expansion or swelling of the tube due to internal tube pressurization caused by plug leak-by and subsequent thermal expansion of the entrapped water during heat-up cycles. Since the resulting internal pressurization may cause plastic deformation or swelling over the entire length of the tube, swollen tubes are preventatively stabilized full length to mitigate the potential effects degradation to the adjacent tubes.

Severed Tube B66-130 was not stabilized because the upper span region of the tube was removed as part of the root cause investigation and all surrounding tubes were plugged with stabilizers in the upper two tube spans. Tube B150-14 was swollen only in the region above the 15th tube support plate and was stabilized from the upper tubesheet through the 14th tube support plate. This tube was also obstructed in the 6th to 7th tube span between support plates due to a previously stuck eddy current probe, which prevented the installation of a full length stabilizer.