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Westinghouse Electric Corporation | Energy Systems

Nuclear Technology Division
Box 355
Pittsburgh Pennsylvania 15230-0355

Mr. Brian Sheron
Office of Nuclear Reactor Regulation
US Nuclear Regulatory Commission
Washington, DC 20555

CAW-94-727

September 23, 1994

APPLICATION FOR WITHHOLDING PROPRIETARY
INFORMATION FROM PUBLIC DISCLOSURE

Subject: "Response to NRC RAI on the HEJ Sleeved Tube Integrity" (Proprietary)

Dear Mr. Sheron:

The application for withholding is submitted by Westinghouse Electric Corporation ("Westinghouse") pursuant to the provisions of paragraph (b)(1) of Section 2.790 of the Commission's regulations. It contains commercial strategic information proprietary to Westinghouse and customarily held in confidence.

Accordingly, it is respectfully requested that the subject information which is proprietary to Westinghouse be withheld from public disclosure in accordance with 10CFR Section 2.790 of the Commission's regulations.

Correspondence with respect to this application for withholding or the accompanying affidavit should reference CAW-94-727 and should be addressed to the undersigned.

Very Truly Yours,

N. J. Liparulo, Manager
Nuclear Safety Regulatory and Licensing Activities

Enclosure

CLD939:ULB/111593

AFFIDAVIT

COMMONWEALTH OF PENNSYLVANIA:

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COUNTY OF ALLEGHENY:

Before me, the undersigned authority, personally appeared Henry A. Sepp, who, being by me duly sworn according to law, deposes and says that he is authorized to execute this Affidavit on behalf of Westinghouse Electric Corporation ("Westinghouse") and that the averments of fact set forth in this Affidavit are true and correct to the best of his knowledge, information, and belief:

Henry A. Sepp

Henry A. Sepp, Manager
Regulatory and Licensing Initiatives

Sworn to and subscribed
before me this 23RD day
of September, 1994

Lorraine M. Piplica
Notary Public

Notarial Seal
Lorraine M. Piplica, Notary Public
Monroeville Boro, Allegheny County
My Commission Expires Dec. 14, 1995
Member, Pennsylvania Association of Notaries

(1) I am Manager, Regulatory and Licensing Initiatives, in the Nuclear Technology Division, of the Westinghouse Electric Corporation and as such, I have been specifically delegated the function of reviewing the proprietary information sought to be withheld from public disclosure in connection with nuclear power plant licensing and rulemaking proceedings, and am authorized to apply for its withholding on behalf of the Westinghouse Energy Systems Business Unit.

(2) I am making this Affidavit in conformance with the provisions of 10CFR Section 2.790 of the Commission's regulations and in conjunction with the Westinghouse application for withholding accompanying this Affidavit.

(3) I have personal knowledge of the criteria and procedures utilized by the Westinghouse Energy Systems Business Unit in designating information as a trade secret, privileged or as confidential commercial or financial information.

(4) Pursuant to the provisions of paragraph (b)(4) of Section 2.790 of the Commission's regulations, the following is furnished for consideration by the Commission in determining whether the information sought to be withheld from public disclosure should be withheld.

(i) The information sought to be withheld from public disclosure is owned and has been held in confidence by Westinghouse.

(ii) The information is of a type customarily held in confidence by Westinghouse and not customarily disclosed to the public. Westinghouse has a rational basis for determining the types of information customarily held in confidence by it and, in that connection, utilizes a system to determine when and whether to hold certain types of information in confidence. The application of that system and the substance of that system constitutes Westinghouse policy and provides the rational basis required.

Under that system, information is held in confidence if it falls in one or more of several types, the release of which might result in the loss of an existing or potential competitive advantage, as follows:

(a) The information reveals the distinguishing aspects of a process (or component, structure, tool, method, etc.) where prevention of its use by any of Westinghouse's competitors without license from Westinghouse constitutes a competitive economic advantage over other companies.

(b) It consists of supporting data, including test data, relative to a process (or component, structure, tool, method, etc.), the application of which data secures a competitive economic advantage, e.g., by optimization or improved marketability.

(c) Its use by a competitor would reduce his expenditure of resources or improve his competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing a similar product.

(d) It reveals cost or price information, production capacities, budget levels, or commercial strategies of Westinghouse, its customers or suppliers.

(e) It reveals aspects of past, present, or future Westinghouse or customer funded development plans and programs of potential commercial value to Westinghouse.

(f) It contains patentable ideas, for which patent protection may be desirable.

There are sound policy reasons behind the Westinghouse system which include the following:

(a) The use of such information by Westinghouse gives Westinghouse a competitive advantage over its competitors. It is, therefore, withheld from disclosure to protect the Westinghouse competitive position.

(b) It is information which is marketable in many ways. The extent to which such information is available to competitors diminishes the Westinghouse ability to sell products and services involving the use of the information.

(c) Use by our competitor would put Westinghouse at a competitive disadvantage by reducing his expenditure of resources at our expense.

(d) Each component of proprietary information pertinent to a particular competitive advantage is potentially as valuable as the total competitive advantage. If competitors acquire components of proprietary information, any one component may be the key to the entire puzzle, thereby depriving Westinghouse of a competitive advantage.

(e) Unrestricted disclosure would jeopardize the position of prominence of Westinghouse in the world market, and thereby give a market advantage to the competition of those countries.

(f) The Westinghouse capacity to invest corporate assets in research and development depends upon the success in obtaining and maintaining a competitive advantage.

(iii) The information is being transmitted to the Commission in confidence and, under the provisions of 10CFR Section 2.790, it is to be received in confidence by the Commission.

(iv) The information sought to be protected is not available in public sources or available information has not been previously employed in the same original manner or method to the best of our knowledge and belief.

(v) The proprietary information sought to be withheld in this submittal is that which is appropriately marked in "Response to NRC RAI on the HEJ Sleeved Tube Integrity", (Proprietary), September, 1994, being transmitted by Wisconsin Electric Power Company letter and Application for Withholding Proprietary Information from Public Disclosure, to Document Control Desk, Attention Mr. Brian Sheron. The proprietary information as submitted is expected to be applicable in other licensee submittals in response to certain NRC requirements for the implementation of steam generator tube repair products and services.

This information is part of that which will enable Westinghouse to:

(a) Provide documentation for steam generator HEJ sleeving services.

(b) Provide documentation for test data on degraded steam generator tubes with HEJ sleeves installed.

(c) Provide documentation for HEJ sleeve operating experience.

(d) Assist the customer in obtaining NRC approval.

Further this information has substantial commercial value as follows:

(a) Westinghouse plans to sell the use of similar information to its customers for purposes of meeting requirements for licensing documentation.

(b) Westinghouse can sell support and defense of the technology to its customers in the licensing process.

Public disclosure of this proprietary information is likely to cause substantial harm to the competitive position of Westinghouse because it would enhance the ability of competitors to provide similar methodologies and licensing defense services for commercial power reactors without commensurate expenses. Also, public disclosure of the information would enable others to use the information to meet NRC requirements for licensing documentation without purchasing the right to use the information.

The development of the technology described in part by the information is the result of applying the results of many years of experience in an intensive Westinghouse effort and the expenditure of a considerable sum of money.

In order for competitors of Westinghouse to duplicate this information, similar technical programs would have to be performed and a significant manpower effort,

having the requisite talent and experience, would have to be expended for developing testing and analytical methods and performing testing.

Further the deponent sayeth not.

Proprietary Information Notice

Transmitted herewith are proprietary and/or non-proprietary versions of documents furnished to the NRC in connection with requests for generic and/or plant-specific review and approval.

In order to conform to the requirements of 10 CFR 2.790 of the Commission's regulations concerning the protection of proprietary information so submitted to the NRC, the information which is proprietary in the proprietary versions is contained within brackets, and where the proprietary information has been deleted in the non-proprietary versions, only the brackets remain (the information that was contained within the brackets in the proprietary versions having been deleted). The justification for claiming the information so designated as proprietary is indicated in both versions by means of lower case letters (a) through (f) contained within parentheses located as a superscript immediately following the brackets enclosing each item of information being identified as proprietary or in the margin opposite such information. These lower case letters refer to the types of information Westinghouse customarily holds in confidence identified in Sections (4)(ii)(a) through (4)(ii)(f) of the affidavit accompanying this transmittal pursuant to 10 CFR 2.790(b)(1).

RESPONSE TO 9/16/94 AND 9/19/94 REQUESTS FOR ADDITIONAL INFORMATION
TECHNICAL SPECIFICATIONS CHANGE REQUEST 175
POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2

Structural Integrity

1. **(9/16/94) With respect to postulated flaws in the upper transition, given the uncertainty in crack growth rates, detection thresholds and probability of detection, consider the size range of undetectable flaws and analyze the effects of undetected flaws in this region on tube integrity, accident analyses, and leakage rates.**

   Provide the results of experiments verifying the load carrying capability of tube and sleeve assemblies with cracks located in the upper hard roll transition and the upper hydraulic roll transition. If such tests have not been performed, discuss any plans to perform such testing.

   In the analyses and experiments, consider, for example, a range of complex flaw geometries with throughwall crack segments ranging from 180° to 360° and 40% to 80% throughwall cracked ligaments over the remainder of the tube circumference. Compare the factors of safety for the range of crack geometries described above.

Introduction

There have been three occurrences of confirmed cracking (or indications) at the hydraulic expansion upper transition. One of the indications, assumed to be circumferential cracking, at Kewaunee was located at the elevation of the upper transition, and two instances of PWSCC were observed in tubes removed from Doel 4. The indication at Kewaunee was estimated to have a total length of ~35°. This indication was the smallest reported indication from the Spring 1994 inspection outage at Kewaunee. One of the cracks at Doel was reported to be 160° long on the OD of the tube and 180° long on the ID of the tube. The second was reported to consist of three cracks in the same plane and adjacent to each other with a total length of 34°. No other cracks were found in the specimens. There was no leakage associated with the indication in the Kewaunee tube, or with the second Doel tube since the cracks were not throughwall. The throughwall (TW) crack at Doel is reported to have exhibited a leak rate of ~124 gpd.

To address the potential impact of cracks below the threshold for detection, estimates must be made of the depth, the length, and the potential growth rate of such cracks. Based on the results of the NDE testing using the Cecco-5 eddy current probe, a conservative estimate of the depth of non-detected cracks for this analysis is on the order of 50% TW. Additional consideration can be given to deeper non-detected cracks, however, in this case some moderation in the selection of a circumferential extent should be exercised since this would imply non-detection by multiple coils. As an extreme example, it would

not be credible to postulate a non-detected 100% TW crack extending 360° around the tube.

Crack Length & Depth

The most conservative estimate of the length is to assume that the crack extends 360°, i.e., all the way around the circumference of the tube. Based on the ECT results it is judged that it would be extremely unlikely to not detect a 50% TW crack with a circumferential extent of 360°. Some ongoing work indicates that effective analyses may be performed by considering an equivalent 360° depth of penetration based on the MRPC area of a partial throughwall (PTW) crack. Here, the MRPC area is found as the maximum depth times the measured length. Thus, a 180° circumferential crack with a 50% maximum depth would be analyzed as a 360° crack with a depth of penetration of 25%.

Growth Rates & Structural Limit for 360° Cracks

There are no directly measured data for the radial growth rate of circumferential cracks in tubes which have been sleeved using HEJ sleeves. However, there are operating data on the radial growth of circumferential cracks from tubes at Doel (HEJ sleeved), McGuire (kinetically welded sleeved), and Maine Yankee (top-of-tubesheet explosive expansion). There is also operating data on the radial growth of circumferential cracks in Alloy 600 mechanical plugs. The McGuire data is not considered applicable owing to the gross difference in the installed configuration of the sleeve. In addition, the operating time was ~20% longer than for Doel, and the temperatures at the location of interest are similar, resulting in a slightly lower inferred growth rate. Information available on growth rates at Maine Yankee are based on assigning a uniform depth of penetration to non-uniform cracks. The method consists of finding a uniform crack depth with the same area as obtained from the product of the maximum depth from RPC inspection times the total length from the RPC inspection. The information reported indicates a radial growth rate of 12.5% per effective full power year. The tube thickness at Maine Yankee is 2 mils less than that in Westinghouse Model 44/51 SGs, thus the radial growth rate would be ~12% per year. This is less than that considered in the following structural analysis.

Some data is also available on growth rates from Arkansas Nuclear One (ANO) steam generator tube inspections of circumferential ODSCC indications at the top of the tubesheet of kinetically expanded tubes. These data indicate TW growth rates on the order of 1.7 mils per year or about 3.5% of the tube thickness. The information also indicates a 90% to 95% upper bound on the order of 21% per year when scaled to Model 44/51 tubes. Since the cracks are in unsleeved tubes and near the top of the tubesheet, it would be expected that the temperature at the crack locations at ANO is closer to the hot leg operating temperature of 600°F, i.e., higher than at potential crack locations in HEJ sleeved tubes. In addition, the tube material is high temperature mill annealed Alloy 600. However, the rates reported are in line with those previously discussed, thus, the ANO data is not bounding

relative to the following sleeved tube integrity analyses. It is noted that one indication was reported to have exhibited growth of 100% in one year. A more likely scenario is that it had a significant depth at the beginning of the cycle and was undetected.

The TW growth rate at Doel can be estimated to be 0.043" per year at 595°F (the temperature on the ID of the tube at the elevation of the upper hydraulic transition). The temperature at a similar location in a 7/8" diameter tube is calculated to be 568°F assuming a linear temperature gradient through the sleeve and the tube. Crack growth rates may be compared using Van Rooyen's equation, where the rate, r_2, at a temperature of T_2 in °K and stress σ_2 can be estimated from the rate, r_1, at T_1 and σ_1 as

$$r_2 = r_1 \left[\frac{\sigma_2}{\sigma_1} \right]^4 e^{-\frac{Q}{R}\left(\frac{1}{T_2} - \frac{1}{T_1}\right)}, \tag{1}$$

where Q is the activation energy of the material and R is the universal gas constant (1.987 cal/mole/°K). The activation energy for Alloy 600 material ranges from ~35,000 to ~50,000 cal/mole. If the stress level is taken to be the same, expected to be conservative owing to the thicker tube material, relationship (1) becomes,

$$r_2 = r_1 e^{-\frac{Q}{R}\left(\frac{1}{T_2} - \frac{1}{T_1}\right)}. \tag{2}$$

Substituting the appropriate values for the 7/8" diameter tubes, the growth rate would be expected to be from 13.4% to 24.5% of that experienced at Doel, or 5.8 to 10.5 mils per year. Relative to the tube thickness, these rates are 11.5% to 21.1% per year. The calculated $3\Delta P_{NOP}$ structural limit load depth for 7/8" diameter tubes with lower tolerance limit (LTL) material properties is 74.2% based on uniform cracking around the circumference using Kewaunee operating parameters. For Point Beach 2, structural limit depth is 78.9%. This limit is conservatively based on assuming the crack to be on the ID of the tube. Thus, in tubes with LTL properties and a lower extreme activation energy (maximum growth rate), missed indications of 53.1% uniform depth (57.8% at Point Beach 2) would not be expected to exceed the RG 1.121 requirements at the end of cycle (EOC).

The same calculation was repeated using the apparent growth rate for Alloy 600 mechanical plugs, a situation where the applied residual stress is likely to be higher than in the sleeve transition areas. Using the maximum observed growth rate for the mechanical plugs, the growth rate for 7/8" tubes would be expected to be 16.5% to 23.4% per year depending on the material activation energy. If the microstructure of the tube material relative to the plug material is accounted for, the calculated rates would be reduced significantly. However, even using the unadjusted maximum mechanical plug growth rates, 360° indications

at 50.8% depth (55.5% at Point Beach 2) at the beginning of cycle (BOC) would not be expected to exceed the RG 1.121 limits at EOC.

It is worthwhile noting that these evaluations considered the affected tube to have LTL material properties, while in-service cracking of SG tubes is usually observed in material with average or above average properties. Thus, additional margin has been afforded by the selection of the material strength. Finally, since cracking would not be expected to progress beyond the structural limits of RG 1.121, no effect on leakage would be expected.

Bending on an Undetected 360° Crack

Since the circumferential crack is assumed to be in a tube in which cracking has initiated at the hardroll lower transition, an assessment of the potential for a significant bending moment to be acting at the elevation of the crack is necessary. Although the applied load is axial, bending will develop at the elevation of a TW circumferential crack since the load carrying area of the tube is not symmetric with respect to the tube axis. For a capped tube with no lateral restraint, such as is provided by the TSPs, the tube would eventually bend significantly off-axis due to the load on the crack flanks, assuming the pressure could continue to be applied.

Even with the lateral restraint provided by the TSPs, the tube will attempt to bend at the location of the crack in order to displace the neutral axis of the remaining material in line with the applied axial load (which remains along the original axis of the tube due to the restraint at the bottom of the tubesheet and at the TSPs). The maximum lateral displacement that could be expected to occur at the lower crack elevation is less than the mean radius of the tube, i.e., less than 0.4125".

The effect of bending at the elevation of the TW crack, on a postulated higher 360° partial throughwall crack, can be estimated by considering the lateral force necessary to displace the tube back to its original axis. Assuming the tube to be built-in at the tubesheet joint and at the TSP (conservative) results in a bending stress of approximately 4% of the applied axial stress. The effect of the bending is assessed by considering the axial load to be increased by 4%. This results in a decrease in the critical PTW depth of ~1% and, therefore, does not significantly affect the above conclusions relative to tube integrity. No experiments have been performed to confirm this conclusion, however, since Alloy 600 is a very "tough" material (the critical value of the elastic-plastic energy release rate, J_C, is on the order of 3600 lb_f/in), failure in the presence of cracks can be reasonably predicted by a plastic instability analysis using the flow stress of the material if the remaining ligament is of sufficient thickness (on the order of 15% to 20% of the thickness of 7/8" diameter tubes) to accommodate the deformation of the opening of the crack tip. Since the assessment of growth relative to non-detected depths indicated that EOC crack depths greater than 80% of the tube thickness are not considered credible for 360° cracks for one cycle of

operation, the requirement that the remaining ligament be greater than 15% to 20% of the tube thickness is met and verification tests are not planned.

For a tube with a 360° circumferential crack with a depth of ~80%, the imposed displacements from the TSPs, the tubesheet (TS), and TS bow, lead to an imposed bending of the section of the tube between the TS and the first TSP, elastic rotation at the cracked section and, finally, a plastic crack tip opening displacement (CTOD). The magnitude of this CTOD value is on the order of a few mils. Throughwall cracks in SG tubing are easily seen to blunt 40 to 50 mils before crack growth initiates. Thus, the ligament of interest will accommodate a few mils of plastic stretch. For throughwall cracking, relative to leak before break considerations, test results show that crack openings required for burst are very much larger than the opening developed by the maximum imposed displacements. The burst behavior of tubes with throughwall cracks will be unaffected by the displacement of the present concern.

Mixed Throughwall and Partial Throughwall Cracks

As with previous considerations on non-detected cracks, some assumptions must be made relative to the length and depth distribution of an individual crack. The Cecco-5 probe to be used for the inspection of the sleeved tubes has demonstrated 94% detection of 40% deep by 1/4" long EDM notches, and 100% detection of 50% deep notches. The probe consists of a pair of transmit and receive coil bracelets. The bracelets are offset circumferentially in order to provide full coverage of the tube. There are a total of sixteen (16) overlapping sensing areas. Ignoring the overlap, each sensing area can be considered to be 22.5°. The appropriate assumption for a non-detected crack is the superposition of a non-detected 360° crack with a non-detected crack of some limited circumferential extent.

Using lower bound limit load analysis for a free-span circumferential crack with no lateral restraint (NUREG/CR-3464) and upper bound tensile overload analysis, two 360° uniform EOC crack depths were considered to determine the critical angle for a superposed throughwall segment of the crack. For a 60% uniform crack, the critical angle, per RG 1.121 requirements, for a crack in a tube with LTL material properties was found to lie between 71° and 138°. For a 70% uniform depth the corresponding results are 29° and 66°. The true critical angle of the crack would be expected to lie between the two bounds. Considering only the postulated SLB pressure, the critical angle for the 60% uniform depth case is from 110° to 203°. The result for 70% uniform depth is 77° to 152°. Thus, a postulated free-span, non-detected crack assumed to be of 40% uniform depth with an 80% depth segment extending over almost two sensing areas, in a tube with LTL material properties, and growing at near maximum expected growth rates in both the radial and circumferential directions, e.g., 20% per year and ~35° per year (recall that 45° was selected to be a conservative bound for the discrimination of inspection results), would be expected to meet the RG 1.121 requirements at the EOC.

For the 60% uniform throughwall scenario, the expected EOC leak rate during normal operation would be expected to be on the order of 120 gpd. The expected leak rate during postulated SLB would be ~1400 gpd, or about 1 gpm.

8. (9/16/94) With respect to question #1 above:

a) Provide results of experiments and/or analyses to assess the potential impact of bending induced binding on the load carrying capacity of tube/sleeve assemblies with cracks located in the region at and above the top hardroll transition to the top of the upper hydraulic roll transition. Discuss the potential for any predicted binding effects to occur in actual in-situ steam generator tubes. The staff finds the effects of bending at the lower transition to be significantly different from that of an unsleeved tube and feels that this issue may be important to understanding tube/sleeve performance for upper transition performance.

Except to demonstrate that the instability analysis presented in Reference 1 is always conservative relative to the tested specimens, no credit has been assumed for bending induced binding of the sleeve-to-tube joint. The test results have demonstrated minimum failure loads on the order of [ ]^{a,b,c} higher than the predicted failure loads for cracks of less than 360° extent. For 360° cracks the failure load is predicted to be zero. First slip test results have ranged from [ ]^{a,b,c} with an average of greater than [ ]^{a,b,c}. Tensile test data at 600°F for 240° throughwall slits at the top of the lower roll transition where the tube failed in the ligament were [ ]^{a,b,c}. These values exceed the RG 1.121 most stringent requirement (1879 lb_f) by a large margin. Plastic overload of the ligament would be predicted at about 2900 lb_f, so a bending lockup effect of [ ]^{a,b,c} was indicated during the tests. For specimens which did not fail in the ligament, sleeve failure occurred at about 8000 lb_f.

In situ, the tubes are always subject to bending loads during operation of the plant, and to a lesser extent all of the time. The latter source of bending is due to the fact that perfect, coaxial alignment of the TSP and tubesheet holes is impossible. During operation, bending results from the differential thermal expansion of the tubesheet at the primary side temperature relative to the TSPs at the secondary side temperature. This effect results in the maximum bending stress being on the side of the tube that is radially outboard from the center of the SG. Only minimum bending stress would be expected to be developed in tubes near the center of the SG. Additional bending loads are developed due to the bowing of the tubesheet from the primary-to-secondary pressure difference. These loads will increase during a postulated SLB due to the higher pressure difference, i.e., 2560 psi versus ~1400 psi during normal operation. Based on the testing performed, the bending may not have to be significant to lead to significant binding loads. Near the center of the SG, the bending loads will be a minimum. Bending loads will also be reduced near the periphery of the tubesheet. For a very short

time at the beginning of a postulated SLB, the bending loads will be increased due to the flow of water toward the periphery of the tubesheet.

Up to the top of the hydraulic expansion, the bending stiffness of the tube/sleeve combination will be ~1.8 times the bending stiffness of the tube alone. At the same time, the restraint of the TSPs and the rotation of the TS will be essentially unchanged. The net effect is an increase of the lateral displacement of the tube/sleeve at the elevation of the HEJ relative to a tube without a sleeve. Because of the relatively long length from the HEJ to the first TSP, it is not likely that the increase in bending stress in the tube above the HEJ is significant. A quantitative discussion of the potential bending effects was provided in the response to Question 1.

It is also likely that bending induced binding could result in the hydraulic expansion region above the hardroll. Since the testing program did not include specimens which were cracked at the hardroll upper transition, this phenomenon was not observed. Such binding would be expected to impart axial load carrying capability to that sleeve/tube interface, and would also be expected to impart added leak resistance to the hydraulic upper annulus. This has not been investigated experimentally and there are no plans to do so since binding in this region is not being relied upon to meet the requirements of RG 1.121. No structurally significant growth of undetected circumferential cracks would be expected during one cycle of operation.

For cracking situated in the hardroll upper transition or upper hydraulic transition, bending lockup effect would be reduced and the tube longitudinal strength can be predicted by a plastic overload analysis. Recall that the structural limit for 360° cracks in Point Beach 2 tubes with LTL material properties was found to be 78.9% of the tube thickness. Based on Cecco-5 detection thresholds, it is reasonable to assume that cracks greater than 40% deep at these locations would be detected. Since experience has indicated the apparent growth rate to be slow, it is unlikely that indications at these locations would represent a potential for separation. Regardless, structural integrity is conservatively predicted by plastic overload, as if the indications were in the lower transitions, and the integrity of non-detected indications at these locations would not be considered a credible source for the potential to impact tube integrity.

Projected Leak Rates

6. **(9/16/94) Since the possibility exists for flaws at the lower transition and upper transition in the same tube roll, the system (tube) compliance, or stiffness, under upset or accident conditions is reduced due the presence of two "hinges" at the flaw locations. Given this reduction in lateral tube stiffness (cracks cause reduction of the second moment of inertia), it can be postulated that multiple tube ruptures could more easily result as a cascading effect of the first rupture: the leak jet side loading and more compliant tube could result in large deflections with potential for loading adjacent, weakened tubes, and induce more failures in fairly rapid succession. What effect would this have on leakage rates and accident analyses?**

The possibility does exist for indications at multiple locations. However, this possibility should be considered in light of the available data. There were no tubes with multiple indications identified at Kewaunee. The inspection at Kewaunee consisted of looking at over 4,000 sleeved tubes, of which 78, only 1.8% of all sleeved tubes, were found to exhibit indications. One tube, 0.02% of all sleeved tubes, exhibited a circumferential indication above the sleeve/tube hardroll. This indication had a conservatively calculated margin against burst of at least 6 during normal operation - twice the RG 1.121 requirement - and a margin against burst during SLB of about 4. One tube exhibited an axial indication within the sleeve/tube hardroll. The length of the indication would meet the requirements of RG 1.121 even if it was a free-span indication. The presence of the sleeve inboard of the indication could add to its burst resistance because the inward reaction to opening of the flanks would be restricted. The hydraulic proof testing has demonstrated that the hardroll interface does not catastrophically open at pressures exceeding the RG 1.121 structural requirements. Of the remaining indications, seven potentially exceeded the repair criteria set using LTL material property limits. If the LTL property limit was adjusted to account for the strain hardening of the material during the hydraulic expansion, it is more likely that only four would exceed the three times normal operating limit, and two could exceed the allowable angle for 1.43 times the SLB pressure. Since cracking is generally observed in material with average or higher than average strength, it is also likely that none of the indications actually exceeded RG 1.121 limits. All of the indications were assumed to be throughwall over their entire detected length - a very conservative assumption. The overall conclusion is that if all of these indications had been located above the hardroll, it is very likely that none of them would have been significantly challenged by the SLB pressure.

Relative to the only confirmed instance of tube cracking, there was no evidence, from the destructive examination, of any other cracks in the two tube sections removed from Doel. The indication that leaked during operation would not have burst during a SLB, and would likely have leaked at less than 1 gpm. The indication in the second tube would neither have burst nor

leaked during SLB.

Based on the operating experience with sleeved tubes, it is considered incredible to postulate two plastic hinges being operative at the same time. It is also considered incredible that two such tubes could be located adjacent to each other, with the second being slightly stronger than the first such that incremental loading would result in it developing multiple plastic hinges. To minimize the total stiffness from two cracks the ligaments from each would have to be in line along the axis of the tube. In order for a plastic hinge to develop, cracking must be throughwall or almost throughwall around most of the circumference of the tube. The reaction force to the outflow of water would be directly opposite to the direction of displacement that would open the crack(s). Thus, if the reaction force was sufficient to bend the tube towards its neighbor, it would also act to close the crack(s) until equilibrium was reached. This equilibrium position would be such that the tube would not have returned to its original location before the flow started. If the motion did result in closing of the crack, the bending stiffness would increase since the crack faces would be brought into contact/compression by additional bending. Thus, the postulated weakened neighbor would not be contacted and the postulated cascading effect would not occur.

It should also be noted that the efflux of water from a large crack(s) would be in the form of a planar spray as opposed to a stream. For most orientations along the crack front, the reaction to outflow in one direction would be in equilibrium, or near equilibrium, with the reaction to outflow at 180° to the first orientation.

It is also prudent to note that during tensile testing, the maximum amount of bending introduced to any of the samples was approximately 3 times less than the nominal tube pitch, suggesting that the stiffness of the sleeve adds to the lateral strength of the potentially degraded tube.

9. (9/16/94) Provide the following information regarding the leakage from potential tube cracks located at or above the upper hard roll transition in HEJ sleeve locations.

a) Provide the results of experiments or analyses to quantify the leakage rates under normal operating and postulated accident conditions for the range of cracks and situations described in questions 1 and 8 above, at the upper hard roll transition and the upper hydraulic roll transition.

No tests are planned to address cracking at these locations. Leakage at the upper hydraulic transition would be predicted by currently available industry data regarding leakage from circumferential indications. Since no sleeved tube leakage from prototypic joints in domestic units has been detected to date, and eddy current detectability would be further increased at this location due to the minimal amount of tube diameter change, it is not credible to consider this location as a potential leakage source. In addition, any undetected degradation in the inspected

sleeved hot leg tubes would be expected to be less than 40% throughwall.

Leakage at the upper roll transition would be greatly reduced from postulated indications at the upper hydraulic transition due to the thin gap between the tube and sleeve in the hydraulic expansion region. At operating temperatures this gap would be expected to be about [ ]^{a,c}. Additionally, the [ ]^{a,c} hydraulically expanded length provides even further reduced leak rates due to length effects of the thin gap.

b) Provide analyses indicating the number of leaking tubes with various crack geometries at or above the upper hard roll transition that could be tolerated without exceeding applicable Part 100 radiological limits under postulated accident conditions.

A 73° throughwall circumferential indication would be expected to leak at about 150 gpd (0.1 gpm) at a primary to secondary pressure difference of 1434 psi. The expected number would be lower for Point Beach due to a current primary to secondary pressure difference value of 1225 psi. At SLB conditions, a 110° throughwall crack would be expected to leak at about 1 gpm while a 180° throughwall crack would be expected to leak at about 5 gpm. Wisconsin Electric calculations have indicated a SLB leak rate of 25 gpm would result in off-site dose within the 10% of Part 100 guidelines for a reactor coolant activity of 1.0 μCi/gm dose equivalent iodine 131. So, conservatively speaking, 25 tubes with postulated 110° throughwall cracks, and five (5) tubes with postulated 180° cracks could be tolerated. Due to the thin gap effects of the sleeve/tube hydraulically expanded length, leak rates for indications at the upper roll transition would be far less than the above values. Again, since there is no domestic history of leakage from this area and a sample of Point Beach sleeved hot leg tubes will be inspected at the next outage, it is improbable that indications in these regions would impact tube leakage integrity.

c) Discuss the potential for detecting primary to secondary leakage.

In-line monitors are utilized for the detection of rad gases. The minimum detectable primary to secondary leakage level is less than .5 gpd (based on the detector's LLD of 4×10^{-7} μCi/cc). The response time of the instrument is 2 seconds and the delay until indication is available to the operators in the control room is 5 to 10 seconds.

The monitoring points for these detectors are:

1) Steam jet air ejector (condenser offgas) discharge (unit specific)--Primary method for primary to secondary leak detection.

2) Combined (for both units) air ejector discharge

3) Steam generator blowdown--Normally monitors the combined

effluent of both steam generators but operators can select to monitor blowdown from either steam generator

4) Steam generator blowdown tank

The detectors feed into the plant process computer system (PPCS) and indication and alarms are available to operators in the control room. The alert setpoint is the lowest of the following values:

- Two times the statistical average of the detector's lowest unit of detectability, or
- 40 gpd, or
- 15 gpd above current reading.

The PPCS can supply daily, hourly, ten minute and one minute averages to the operator for trending.

The display and data retention/trending system is a computerized stand alone system which also communicates with the PPCS. Instantaneous data and selectable time trends are available to control room operators on numerous computer monitors.

Several levels of procedural guidance are available to the operators, including Abnormal Operating Procedures (AOPs) and Emergency Operating Procedures (EOPs). AOPs address leakage limits below that which would lead to a reactor trip or safety injection actuation. EOPs address leaks that cause a reactor trip, tube ruptures and these conditions combined with other major accidents, such as steam line break. The EOPs are based on the Westinghouse Owners Group (WOG) Emergency Response Guideline (ERG) procedure set. The WOG procedures were verified and validated on a typical plant. The PBNP plant specific EOPs have been verified and validated also. The AOPs are based on plant experience at PBNP as well as industry-wide experience and lessons learned.

Other routine procedures provide operators guidance in diagnosis and identification as described below:

1) Once per shift, Operations reviews the 24-hour trends of Unit Air Ejector Discharge Monitor RE-215, Steam Generator Sample Monitor RE-219, and Common Air Ejector Discharge Monitor RE-225 for increasing trends in accordance with PBNP Operating Instruction OI-96, "Steam Generator Tube Leakage Calculation and Evaluation."

2) Each day, Operations calculates steam generator tube leakage from rad gas monitors in accordance with PBNP Operating Instruction OI-96.

3) On Monday, Wednesday, and Friday of each week, Chemistry samples for steam generator tube leakage in accordance with PBNP Chemistry Analytical Methods & Procedure CAMP-101, "Daily Routine Sampling Schedule for Operating, Refueling, or Shutdown Units."

The PBNP action levels are:

1) If steam generator tube leakage is >100 gpd or increasing rapidly, an evaluation for the need to reduce power or shutdown is performed (OI-96).

2) If steam generator tube leakage is >40 gpd or has increased by more than 15 gpd/day, Chemistry samples every 4 hours until stable (OI-96).

3) If steam generator tube leakage is >10 gpm, shutdown as soon as practical but within 24 hours of leak detection in accordance with PBNP Abnormal Operating Procedure AOP-3A, "Steam Generator Tube Leak."

4) If steam generator tube leakage is >150 gpd, place plant in cold shutdown within 30 hours of leak detection per AOP-3A.

Based on simulator exercises performed by plant operators during training and evaluation sessions, we are confident that sufficient and adequate procedural guidance is available to operators to adequately address steam generator tube rupture tube events alone and those which could be compounded with other events.

We have also performed an extensive evaluation of INPO SOER 93-01, "Diagnosis and Mitigation of Reactor Coolant System Leakage Including Steam Generator Tube Ruptures." The areas examined were Operations Management, Emergency Operating Procedures, Radiation Monitoring System, and Training. Our evaluation and recommendations are contained in Nuclear Power Department Memorandum NPM 94-0105, dated March 11, 1994. In addition, we evaluated NRC Information Notice IN 93-56, "Weakness in Emergency Operating Procedures Found as Result of Steam Generator Tube Rupture," and identified no deficiencies.

Because the AOPs and EOPs are presently intended to mitigate any and all steam generator tube leakage and rupture events regardless of the cause mechanisms, we do not plan to make any changes to these procedures.

However, if the proposed acceptance criteria are approved, we will:

1) Increase the frequency at which operators and chemistry personnel measure and trend steam generator tube leakage, and

2) Investigate the possibility of providing additional, diverse monitoring devices for steam generator tube leakage.

1. (9/19/94) The off-site dose assessment states that the maximum primary to secondary leak rate that still meets the requirements of 10CFR100 is 25 gpm. In addition to providing this total allowable leak rate, the per tube leak rate and corresponding allowable number of degraded sleeved tubes should be included. In light of updated leak testing results that have been presented, what leak rate value will be used

per tube for the main steam line break scenario? This value should be valid for the largest reasonable slip distance under main steam line break differential pressures, and should also be valid for the most limiting crack size (224 degrees) at the top of the lower transition. The per tube leak rate value should also reflect the statistical uncertainties that exist in the slip distance and the crack size. The probability of crack detection is postulated to be between 80 and 90 percent and this probability, as well as the uncertainty of the probability, should also be factored into determining the allowable number of degraded tubes. By knowing the total leak rate of 25 gpm and the leak rate per tube, the allowable number of tubes with indications can be calculated. What is the allowable number of tubes with indications proposed to be left in service? What conservatisms exist in such a calculation?

The SLB leak rate to be applied to each tube remaining in service as a result of implementation of the proposed criteria will be [ ]^b. Test data indicates the maximum leak rate was found to be [ ]^b at a pressure differential of 2450 psi. This value has been conservatively adjusted to [ ]^b at 2560 psi. The differences in leak rates for specimens that leaked was not significant. A second specimen leaked at [ ]^b at a pressure differential of 2560 psi. Since the meeting on 9/12/94, two additional leak rate tests were run on specimens with hardroll diameters at the lower end of the range of acceptable hardroll diameters. Leak rate data for these specimens was [ ]^b at a pressure differential of 2560 psi. Therefore, assignment of a leak rate of [ ]^b per tube is considered reasonable. Additionally, leak rate specimens were produced using 0.02" wide throughwall slits. Experience (and fluid dynamics theory) has shown that stress corrosion cracks leak at rates much lower than mechanically produced slits. Also, the throughwall extent of the slits in the test specimens was 240°. This value exceeds the projected EOC throughwall extent of 224°, so additional conservatism is provided by the test configuration. Conservatism is also provided by assuming that each tube will leak at the rate of [ ]^b. Not all indications would be expected to have a throughwall extent equal to that predicted by the EOC structural model; not all indications would be expected to exist at the very top of the hardroll lower transition, and these indications would therefore be expected to have leak rates less than the [ ]^b allowance. It must also be considered that three leak test specimens with 240° throughwall cracks did not leak at SLB conditions. Using this data suggests that only 57% of the indications with 240° throughwall cracks would leak at SLB conditions. When all of these conservatisms are considered, the application of an across-the-board SLB leakage of [ ]^b per tube allowed to remain in service due to application of the proposed criteria is quite conservative, and no further adjustments are necessary. Using this per tube leak rate allowance at SLB conditions, up to 757 tubes could theoretically be allowed to remain in service due to application of the criteria. This would represent about 28% of all sleeved tubes at Point Beach 2. Experience from Kewaunee showed that only about 2% of all sleeved tubes contained eddy

current indications. Additional conservatism is provided that all of the hot leg sleeves at Point Beach Unit 2 are Alloy 600 material. Test results have shown that the Alloy 600 sleeve material, when coupled with Alloy 600 tube material, does not support leakage at SLB pressure differentials, even for 360° throughwall cracks. Regardless, the [ ][b] per tube leak rate allowance will be included even if the sleeve is manufactured of Alloy 600.

The structural model which limits BOC measured angular extent such that EOC throughwall extent should not exceed 224° such that tube separation during either normal operation or SLB pressure end cap loading would not occur. Therefore, it is not credible to consider tube separation and slippage during a SLB. Tensile testing on tubes with 240° throughwall slits and slits represented by the EOC structural model indicate that the point of ligament failure due to plastic overload is a minimum of about [ ][a,b,c]. This value exceeds the RG 1.121 most stringent loading requirements by approximately a factor of 2, and exceeds the actual SLB pressure end cap loading by a factor of 4. Additionally, tensile testing has shown that after ligament separation, frictional forces during tube pull-out exceeded the RG 1.121 loading by about 1.5 times. Therefore, there is no basis to suggest that slippage of any magnitude be considered in the assignment of a per tube leak rate for SLB conditions. The structural model also neglects tube-to-tube support plate friction at the tube support plate intersections. Considering the industry database regarding tube pull forces, which typically exceed 1,000 lb_f for 3 intersections, and the fact that a large number of dented intersections exist at Point Beach 2, there is a very large probability that tube-to-tube support plate interference loads exceed the maximum load applied to the tube from pressure end cap loading, which implies that the interference loads at the tube support plate intersections will prevent tube slippage even in a tube which has experienced a complete circumferential separation. This statement would be considered valid for any postulated separation point including the upper hydraulic expansion transition and the hardroll upper transition.

Probability of detection using the Cecco-5 probe for 100% throughwall indications is 100%. Therefore, no further adjustments for probability of detection are required.

2. **(9/19/94) For normal operating differential pressures, resulting sleeved tube leak rates show considerable variation among the limited number of tests performed (3 dpm vs. 50 dpm, for example). Please state and justify a bounding limit on leak rates for normal operating differential pressures which addresses the statistical uncertainty associated with the limited database or test results. This bounding value should also account for probability of crack detection and crack size and the uncertainty in these two parameters. Using the allowable degraded tube number from the first question and the per tube normal operations leak rate, calculate a total leak rate and compare this to the leak limit of 150 gpd. Preliminary calculations have shown**

that a per tube leak rate of 50 dpm (and using a conversion factor from the submittal to go from dpm to gpd) with 1230 degraded sleeved tubes in service may exceed 150 gpd limit.

The historical basis of the normal operating primary-to-secondary leak rate is to provide protection against tube rupture during faulted conditions by alerting the plant operators via the detected leakage. For the physical sleeve/tube fit-up geometry, tube motion on the order of 3" would be required to support steam generator tube rupture (SGTR) type RCS release rates. Past NRC precedent shows that the maximum allowable SLB leakage limit which supports off-site dose within the 10CFR100 guidelines has been used to establish the maximum number of tubes to be left in service, not the normal operating primary-to-secondary leakage limit. The 150 gpd limit is used only to identify the possibility of existence of a tube which has experienced crack growth far out of the bounds of the growth rate used in the structural model at any location within the tube, and hypothesized to have experienced separation and partial slippage (even though slippage is considered an incredible event). This value is based partly on previous test data for tubes which were separated by machining within the hardroll flat area. If such a tube were to experience slippage on the order of 1 inch, which is what WCAP-10949 has shown would represent a 95% confidence slip value limited by tube proximity in the U-Bend, potential leakage at SLB conditions would be expected to be several times less than normal makeup capacity. Information was presented during the 9/12/94 meeting which indicated that the flow rate in such a case is limited by the remaining metal-to-metal contact in the original hardrolled areas and the thin gap between the tube ID in the roll expanded region and the sleeve OD in the hydraulically expanded region, which can range from [ ][a,c] on the diameter. For a postulated separated tube to experience leak rates on the order of about 25 gpm, the tube would have to experience slippage of greater than 1", more on the order of about 1.25 to 1.5". Again, flow would be restricted by the thin gap between the tube ID in the hardrolled region and sleeve OD in the hydraulically expanded region.

The use of variance in leak test data at normal operating pressure differentials in drops per minute can be somewhat misleading due to the large number of drops per gallon. The difference between 5 dpm and 60 dpm can seem large, however, the difference between 0.00007 gpm (5 dpm converted to gpm) and 0.0008 gpm (60 dpm converted to gpm) seems somewhat insignificant. The response to Question 1 identifies the extreme conservatisms applied to the per tube leak rate for SLB conditions of [ ][b].

3. **(9/19/94) In the event of steam line/feed line break, on what quantitative &/or qualitative basis can the licensee ensure that the total leak rate from multiple tube leaks would not exceed 25 gpm?**

Addressed in Question 1 (9/19/94) above. The per tube SLB leak rate for tubes left in service due to application of the proposed acceptance criteria will be conservatively assumed to be .033

gpm. If the total projected leakage for the tubes left in service exceeds the maximum permissible SLB leakage of 25 gpm, tubes will be repaired or removed from service so that the projected SLB leakage value is reduced below 25 gpm.

Corrosion Cracking

7. **(9/16/94) Provide the following information regarding the relative susceptibilities to IGSCC of the lower hydraulic expansion, the lower hard roll expansion, the upper hard roll expansion and the upper hydraulic expansion locations:**

   a) **A comparison of the processing of the tube material during the installation of the sleeves and the resulting strain levels and residual stresses for each of these locations. Include a discussion of the variability of the installation processing and implications with regard to the strain levels and residual stresses.**

The procedure for fabricating the upper HEJ includes hydraulically expanding (HE) a [ ]^{a,c} length of the sleeve in the tube. This is followed by hard rolling (HR) a [ ]^{a,c} (including the transitions) length of the sleeve within the hydraulically expanded region. Figures depicting the configuration of the HEJ were provided in WCAP-14157.

The one step hydraulic expansion causes an increase in the tube diameter of from [ ]^{a,c}. The HE has a uniform transition from the unexpanded tube diameter to the expanded diameter. Subsequent to the HE, the hardroll is performed and the tube is expanded in the range of [ ]^{a,c} on the diameter. The interference developed between the sleeve and the tube during the HR provides the joint integrity relative to leak tightness.

Processing differences between the HE and HR regions are that the first is a hydraulic expansion with minimal deformation of the tube, and the second is a mechanical rolling operation that produces significant mechanical deformation. Within the HE process, the processing differences would be related primarily to the degree of expansion of the sleeve/tube, which is dependent on the strength of the tube and tolerances on the equipment. The HE diametral tube expansion is limited by drawing to less than [ ]^{a,c}. The differences in hard roll expansion are similar with diametral expansion limited to [ ]^{a,c}. The fabrication strain and residual stresses would be related to the amount of expansion produced.

$MgCl_2$ testing of the HEJ geometry (stainless steel surrogate tubing) suggest, that the residual stresses are generally below [ ]^{a,c,e} at the OD and ID of the tube. Residual stress measurements by the parting/layer removal technique showed compressive stresses on the OD of the tube and tensile stress of up to [ ]^{a,c,e} at the ID surface. Circumferential residual stresses were negligible at both the OD and ID surfaces. More recent measurement of axial residual stresses introduced during fabrication of prototypic HEJ assemblies showed that axial tensile stresses of between [ ]^{a,c,e} were introduced in the tube between the lower tubesheet joint and the upper HEJ. The measurements were made on four samples and the residual stresses were consistent. The results of these tests indicate that cracking should be unexpected. Thus, the formation of cracks of significant length and depth would not be likely in

short periods of time, e.g., one cycle, unless the operating environment is significantly more severe than anticipated. Since the Point Beach 2 sleeves have been in service for periods of up to 11 years without incident, fast growth rates are not expected.

b) Compare and evaluate the operating experience history of question #3 above with the results of the analyses presented in part "a" of this question.

The boiling $MgCl_2$ test results indicated a slightly higher propensity for cracking on the ID of the tube at the HE lower transition that at the HE upper transition when the surfaces were exposed to the corrosive environment. At the lower transition, one specimen with an expansion of [ ]^{a,b,c}. A second specimen, with an expansion of [ ]^{a,b,c}. One upper transition specimen, with an expansion of [ ]^{a,b,c}. No cracking was observed in the hardrolled region of specimens with expansions ranging from 0 to 30 mils. Comparison of the results for the HEJ geometry to C-ring specimens exposed at the same time implied residual stresses to be less than [ ]^{a,b,c}. The observed cracking and the observed preferred locations for cracking are not predicted by the test data.

c) Provide the results of any experimental residual stress measurements or accelerated corrosion tests conducted on HEJ sleeved tubes with particular focus on the locations and their relative susceptibilities to cracking. Describe any plans to conduct such testing if none has been conducted to date.

Referring to the responses to questions 7.a) and 7.b), the corrosion testing results indicate that the [.]^{a,c,e} The potential for cracking at the hardroll lower transition is discussed in the response to question 7.d).

d) Discuss any potential differences in the incubation time and crack growth rates for cracks located at or below the lower hard roll transition versus at or above the upper hard roll transition.

Potential incubation times and crack growth rates in domestic units can only be compared to the Kewaunee data which showed no indications in the hardroll upper transition and one indication in the upper hydraulic transition. With regard to the upper roll transition, the design of the rollers themselves employ a much shallower taper at the top compared to the bottom. This would inherently produce a condition with a lesser potential for creating a stress riser in the upper transition due to a more gradual diameter change than in the lower transition.

In the case of a free span HEJ configuration that has corrosive environment access at both ends of the assembly, it would be expected that the potential for corrosion could exist at both transitions. In reality, the upper roll transition is somewhat protected by the [ ]^{a,c} created by the hydraulic expansion at operating temperatures. In the lower roll transition, unless a significant throughwall penetration exists

that could replenish the area with corrosive species, the potential for ID corrosion is reduced. Bulk fluid concentrations could affect the tube OD at this location. At the upper hydraulic transition, primary fluid has almost unrestrained access to the area. At the lower hydraulic transition, previous testing has shown complete tube separation below the bottom of the hardroll lower transition does not impact tube integrity, and therefore needs not be addressed.

Testing was conducted on elevated sleeve assemblies in support of the sleeving program being performed at Doel. Recent doped steam tests of this type of geometry (prototypic, except that the roll down at the bottom of the HR was much longer than in field HEJs, and such a level of roll down would not have been accepted for continued service) produced cracks in the roll down region. The cracking was evidenced to be below the top of the hardroll lower transition. Other regions, i.e., the upper HR transition and the HE transitions experienced little, if any corrosion. It has not been determined at this time if the corrosion is related to the long roll down, although several qualitative arguments could support this theory.

Corrosion testing conducted on elevated sleeve geometries for Doel indicated a [.][a,c,e] When examining the geometric fit-up of an elevated sleeve compared to a standard tubesheet sleeve installed in a tube with a tube partial depth roll expansion, it is shown that the free span, unexpanded length of tube between the tubesheet attachment and HEJ is much shorter for the Doel configuration than for Point Beach. In a Model F steam generator the tube is roll expanded to the top of the tubesheet whereas for Point Beach the roll expansion is only 2.75" into the tubesheet. If the tube is considered a spring in an elastic system, the residual load in the tube will be greater for the full depth roll configuration (elevated sleeve) than for the partial depth roll configuration (full sleeve) for similar levels of tube expansion in the HEJ. While this data is not directly applicable to HEJ sleeves installed in Model 44/51 steam generators, it is the only doped steam data available for the HEJ geometry. In summary, [.][a,c,e]

Additionally, with regard to overall potential for degradation in either the upper or lower roll transitions, the tube fixity conditions in the plant could have an impact upon susceptibility. If a tube is fixed at the first support plate, at elevated temperatures the sleeve (Alloy 690) would want to extend by an amount greater than the tube due to the difference in thermal expansion coefficient between Alloy 600 and Alloy 690. This could introduce a tensile force below the hardroll and a compressive force above the hardroll. The tensile forces would tend to introduce cracking while the compressive forces would not. Therefore, if there is a high likelihood of tube fixity at the first support plate the hardroll lower transition would be in a stress state more conducive to cracking than the hardroll upper transition. Such tube fixity conditions are likely at both Kewaunee and Point Beach Unit 2 based on previous tube pull and eddy current examinations.

e) Provide any information that suggests that tubes experiencing cracking at HEJ locations at or below the lower hard roll transition are not susceptible to cracking at locations at or above the upper hard roll transition.

For the Units in question, the field data shows the indications have occurred at the bottom of the HEJ indicating the potential for cracking is greater in these regions. This is consistent with the results of laboratory doped steam tests of HEJs. However, there has been a high temperature foreign plant that has experienced corrosion at the upper side of the HEJ. This is still under investigation.

Non-Destructive Examination

2. **(9/16/94) Discuss and justify the probability of detection for various flaw sizes, considering the lack of field experience (pulled tubes). Discuss the benefits/costs of pulled tube samples.**

The qualification testing of HEJs with Cecco-5 probes was performed using 0.25" long EDM notches, oriented circumferentially and axially, using depths of 40%, 50%, 60% and 80% of the tube wall thickness. Detection performance in excess of 95% was demonstrated for all depths and for both orientations. Concern attaches to this information from the standpoint of the equivalence of EDM notches to cracks in applying the laboratory simulation data to the expected field performance. To address this concern, Westinghouse has used the Cecco-5 probe to inspect cracked specimens produced in laboratory autoclave exposure of HEJ samples to verify corrosive environments. From the data available to date, the Cecco-5 has achieved 100% detection probability for circumferential cracks with depths in excess of 60% of the tube thickness. Thus far, no cracks with shallower penetrations, as demonstrated by metallographic examination, have been available for Cecco-5 testing. A small number of cracks with depths between 40% and 60% have been examined with Cecco-3 probes; the result of this testing demonstrated 78% detection, but the small number of tests needs to be augmented to permit statistical affirmation of the probe's performance. Nevertheless, these data support the expectation that both the Cecco-3 and Cecco-5 probes will have adequate sensitivity to circumferential cracks at the 40% level for the OD cracks which were simulated by the notches and emulated by the crack specimens; detection of ID cracks will be superior to the performance realized for OD cracks.

The validation of the Cecco-5 probe's performance with pulled tube samples is unlikely to provide significant additional basis for confirmation of the qualification testing in the near term. Certainly, absolute verification by the examination in the laboratory enhances the subjective confidence in the technique, but the principles of ECT employed are not novel, and as such, NDE confidence will not be significantly improved by a few more tube pulls performed at great cost and substantial additional radiation exposure to platform workers. The most cost effective method to enhance statistical confidence in the NDE techniques is the examination of laboratory generated crack specimens followed by destructive examination to permit qualification consistent with generally accepted statistical methods.

10. **(9/16/94) Provide the following information regarding proposed nondestructive testing methods:**

    a) **It is our understanding that you plan to use the CECCO probe. If this is not correct, discuss the alternative(s)/ capabilities with respect to the Technical Specifications and Bases, your original submittal requesting NRC approval to install HEJ sleeves, and the NRR Safety Evaluation Report approving HEJ sleeving for your facility relative**

to nondestructive testing of the HEJ sleeve/tube combination.

The HEJ sleeved tubes at Point Beach 2 will be non-destructively examined utilizing the Cecco-5 eddy current probe. Utilizing the proposed acceptance criteria, indications reported from the Cecco-5 examination will then be examined using 3-Coil motorized rotating pancake coil (MRPC) technology. All of the information available from both examinations will be used to evaluate the indication against an approved acceptance criteria to judge whether or not the sleeved tube should remain in service. The proposed criteria consists of several aspects with regard to the location and orientation of any detected indications.

The individual aspects of the criteria are as follows:

1) All indications, regardless of depth, orientation, and extent will not be considered as cause for remedial action, provided the indications are located wholly at or below the bottom of the hardroll lower transition (that material constituting the diameter change of the tube from the hardroll expanded region to the hydraulically expanded region).

2) Axial indications, alone or in conjunction with circumferential indications, which extend above the bottom of the hardroll lower transition will be considered as cause for remedial action regardless of the depth or length of the indications.

3) Circumferential indications which are located, or extend, above the top of the hardroll lower transition will be considered as cause for remedial action regardless of the depth or length of the indications.

4) Circumferential indications which are located within the hardroll lower transition, and may extend below the bottom of the transition, and which are judged to have a single or aggregate extent of greater than 179° will be considered as cause for remedial action regardless of the depth of the indications.

Structural and Leak Rate Testing

4. (9/16/94) Compare the details of the mock-ups versus the range of parameters for SG tubes and field installed sleeves. Consider rolling method differences, if any, and range of dimensional differences between lab samples and SG tubes and sleeves (thicknesses, diameters). Consider the impact of the range of physical differences on the eddy current test detection thresholds, etc.

Test specimens were prepared using two tube material heats and one sleeve material heat. The tube material tensile properties were relatively low compared to the average flow stress for Westinghouse tubing. Tube heat (HT) 1253 had yield and ultimate strengths of 43.3 ksi and 100.8 ksi, respectively, at 600°F. While HT 2761 was not tested for material properties, comparison of the expansion process charts indicates that 2761 has lower material properties than 1253. The flow stress for HT 1253 is 72.05 ksi while the nominal for Westinghouse tubing is approximately 75 ksi.

The test specimens' sleeve ID roll diameters ranged from approximately [$]^{a,b,c}$. The range of acceptable values is [$]^{a,c}$. The field target for sleeve ID roll diameters is [$]^{a,c}$. The test specimens' sleeve hydraulic expansion diameters ranged from 0.705 to 0.708". This level of hydraulic expansion results in a 0.000" to 0.003" tube diameter change. Specimens were hydraulic and roll expanded identically as in the field except that the specimens were expanded and rolled horizontally. The tube and sleeve thicknesses and diameters are considered nominal.

As the joint gains integrity through "bending lockup," the benefit gained by bending lockup should be relatively independent of hardroll diameter provided the minimum diameters are achieved. Previous data contained in the original HEJ sleeving WCAPs indicate that joint integrity over the entire range of diameters is provided. Since the bending lockup occurs early in the load pattern (indicated by apparent sleeve yielding in all specimens) prior to slippage of the joint, the bending lockup benefit should be provided for the entire range of field acceptable diameters.

Testing at 600°F was completed on 9/19/94 in which the slit in the tube was representative of the structural model. Tubes were slit throughwall over 224 degrees and an additional 30% to 40% deep slit was applied at the same elevation as the throughwall slit. Ligament failure loads were found to be [$]^{a,b,c}$. Again, all test values were greater than the most stringent RG 1.121 loading. Also, frictional loads after ligament separation were found to exceed the most stringent RG 1.121 loading by nearly a factor of 2.

Since tubes with smaller hardroll diameters would inherently contain less diametral disparity, eddy current sensitivity should be increased for joints with hardroll diameters in the lower range of acceptability.

HEJ Operating Experience

3. (9/16/94) Provide a leak (failure) history for HEJ sleeves and assess causes.

In April of 1994, seventy-eight (78) sleeved tubes in SGs at the Kewaunee Nuclear Power Plant (KNPP) were reported by NDE to contain indications in the vicinity of the HEJ (recall that the upper joint of a HEJ sleeve is also referred to as a HEJ). At about the same time, two sleeved tubes exhibiting PWSCC at the top of the HEJ hydraulic expansion were confirmed at the Doel 4 Plant in Belgium. The indications in the tubes at Kewaunee have been attributed as likely ODSCC based on consideration of their locations. A complete description of the indications and their locations is provided in Reference 1.

Of a total of 6081 sleeves (4329 at Kewaunee and 1752 at Doel) installed and operational at the two affected plants, only one sleeved tube (at Doel) exhibited any operational leakage (~124 gpd). Despite analyses which indicated that the bulk of the tubes exhibiting indications at Kewaunee would continue to operate safely, all tubes with indications above the bottom of the hydraulic expansion were removed from service. At Doel, a sleeve recovery program was initiated to modify the pressure boundary to above the HEJ via laser weld repair.

In terms of sleeve performance, the HEJ sleeve concept as originally developed as a repair technique for steam generator tubes was qualified to be leak limiting as opposed to being leak tight. While extensive qualification testing of the configuration demonstrated that typical leak rates were zero or very small, leak rates commensurate with applicable Technical Specifications requirements were and are permitted. For the most part, installed HEJ sleeves have exhibited zero leakage. However, in certain rare instances, leakage of the sleeves has been observed following installation and operation of the plant.

A comprehensive review was conducted to determine the extent of any leaking sleeve conditions encountered during the past 13 years. The review disclosed only two sites where sleeve leakage has been observed (San Onofre Unit 1 and Point Beach Unit 2) since the initiation of the use of HEJ sleeves at San Onofre in 1980. While these conditions have no bearing on the disposition of indications like those recently observed at Kewaunee or Doel, a detailed discussion is provided in the following paragraphs.

San Onofre Unit 1

At the start of the 1988 San Onofre Unit 1 mid-cycle outage, a secondary side hydrostatic leak test of the three steam generators identified a total of 19 leaking sleeved tubes. Seventeen of the locations (four in SG "A", eight in SG "B", and five in SG "C") were within the then approved leak limiting criteria for sleeved tubes. Two of the locations exceeded the leak rate criteria. Eddy current testing of the tubes did not reveal any indications in the sleeves from which to attribute the leaks. However, ECT profilometry indicated that several of the

sleeved samples had hardroll expansion diameters outside of the lower tolerance limit for the HEJ design, i.e., the hardrolled diameters were undersized. Specifically, one sleeve lacked a lower joint hardroll, five sleeves lacked the HEJ hardroll, and three contained upper hardrolls of below the minimum expansion tolerance. All nineteen of the tubes were removed from service.

Following a detailed evaluation of the sleeved tubes in question, in concert with a sample eddy current examination of additional sleeved tubes and a test program aimed at assessing sleeve joint performance, it was concluded that the most likely cause of the leaking joints was the placement of the upper HEJ with respect to the existing sludge pile. Examination of sludge pile conditions in conjunction with a supporting test program showed that variability in the sludge hardness could prevent the roll joint from achieving design expansion and result in degraded leak performance.

Point Beach Unit 2

As of the most recent inspection in October 1993, a total of eleven (11) sleeved tubes (9 in SG "A" and 2 in SG "B") have been associated with some small degree of leakage at Point Beach Unit 2. Approximately eight (8) additional sleeved tubes in SG "B", also associated with small leakages, have subsequently been plugged but for reasons other than the leakage itself. In fact, no sleeved tubes at Point Beach have been plugged as a result of a leaking sleeve condition.

The observed leakage in all cases has been very small, ranging from "wet" to a maximum of 4 dpm. The term "wet" in this case means that the tubesheet face in the vicinity of the tubes in question is slightly darker in color than the surrounding tubesheet face, indicative of the presence of surface moisture.

In the current population of nine sleeved tubes associated with leakage in SG "A", four have been tracked from the installation of the sleeve in 1983 to the most recent inspection in October of 1993, providing an accurate assessment of leakage with respect to operating life. In 1983, the four tubes were considered as "wet" consistent with the previous definition. Subsequent inspection during 1993 showed three of the tubes "wet" and one of the tubes with leakage increased to 3 dpm, still well below the allowable limit. This type of performance is consistent with that observed during the HEJ sleeve qualification program.

The leakage or weeping described in the inspection reports has been attributed to tube hardrolls which are shorter than the desired nominal of 2.25". This permitted the accumulation of sludge in the tube-to-tubesheet interface in the design hardrolled zone. The presence of the sludge prevented the sleeve hardrolling from achieving the desired [ ]^{a,c} wall thinning needed to seal the lower joint. Eddy current examination has suggested that in some cases, only 10 to 30% of the expansion required to achieve contact with the tubesheet was obtained during the sleeve installation process.

A test program initiated to assess the effect of the shorter tube installation hardrolled length on the performance of the sleeve concluded that the leakage, if any, as a result of the so called "anomalous tube condition," was well within the Technical Specifications limits and was, therefore, acceptable. With the exception of the four sleeved tubes indicated in SG "B", none of the "weeping" sleeved tubes have been plugged.

A test program initiated to assess the effect of the shorter tube installation hardrolled length on the performance of the sleeve concluded that the leakage, if any, as a result of the so called "anomalous tube condition," was well within the Technical Specifications limits and was, therefore, acceptable. With the exception of the four sleeved tubes indicated in SG "B", none of the "weeping" sleeved tubes have been plugged.

Plant Operation

5. **(9/16/94) Based on the discussion at the September 12, 1994, meeting, do you intend to incorporate the 150 gpd leak rate limit into the Technical Specifications?**

We will incorporate the 150 gpd primary to secondary leak rate limit into the Point Beach Nuclear Plant Technical Specifications in conjunction with NRC approval of the proposed acceptance criteria.

Risk Assessment

1. (9/19/94) In their response to question 1 of RAI on TS change request (175), the licensee stated that there are only two core damage sequences from the steam line/feed water line break in initiating events which result in a CDF above 1E-10 cutoff. These include the following sequences:

   1. Tfb-IR-MS at 8.5E-9/yr.
   2 Tsb-MS-IR-EC at 4.1E-9/yr.

   Tfb = prob. of steam line break/feed line break inside ctmt.= 7E-4
   IR = induced SGTR prob. used in Point Beach PSA = 2.7E-2
   MS = prob. of SG isolation failure used in Point Beach PSA=2.12E-3
   Tsb = prob. of steam line break outside ctmt. = 8E-4
   EC = prob. of operator failing to cool and depressurize RCS = ?

   Given above top event probability values, sequence 1 CDF does not calculate to be 8.5E-9/yr as indicated by licensee's response submittal to RAI. Instead, our calculation using the above probability values shows that sequence #1 CDF is 4E-8 (7E-4 x 2.7E-2 x 2.12E-3). Is there an error in licensee's calculation? Or, are we missing a piece of information that needs to be taken into account for this calculation?

   If the licensee's calculation is in error, what is the correct total CDF increase due to induced SGTR with Tfb and Tsb?

   In addition, the probability value for the term "EC" was not provided in the RAI response submittal. What is its value?

<u>Steam/Feed Line Break Inside Containment, Induced SGTR, Failure of Main Steam Isolation (Tfb-IR-MS)</u>

The Probabilistic Safety Assessment (PSA) core damage sequence Tfb-IR-MS represents the only steam line break/feed line break sequence from the Point Beach PSA which was important to core damage frequency (i.e., for which cutsets exceeded a frequency of 1.0E-10/year). This sequence is made up of the following two cutsets:

1. IRB-INDUCED-SGTR x MS--MSV-OO-02018 x IE-TFB x RECISOLATE-1
2. IRB-INDUCED-SGTR x HEP-MS--EOP-3-02 x IE-TFB x RECISOLATE-1

The values and descriptions of each of the basic events in the cutsets are provided in the table below:

BASIC EVENT ID	VALUE	DESCRIPTION
IRB-INDUCED-SGTR	2.7E-2*	Probability of induced Steam Generator Tube Rupture (SGTR).
MS--MSV-OO-02018	8.57E-2**	Probability of Main Steam Isolation Valve (MSIV) 2018 failure to close.
IE-TFB	7.0E-4/yr	Initiating Event Frequency for Steam/Feedwater Line Break Inside Containment.
RECISOLATE-1	5.0E-2	Probability operator does not take recovery action to mitigate the long term inventory depletion that results from this sequence.
HEP-MS--EOP-3-02	4.75E-3	Probability operator does not immediately diagnose Steam Generator Tube Rupture Event and does not immediately isolate the steam generator.

Notes:

* The Point Beach PSA Individual Plant Examination (IPE) submittal and subsequent information used to calculate core damage frequency presented to the NRC on September 12, 1994, incorrectly used induced steam generator tube rupture with steam generator isolation (IRA-INDUCED-SGTR), which has a value of 2.7E-3. It was estimated that a large ΔP would be experienced only 10% of the time with successful steam generator isolation and, therefore, the value of 2.7E-3 was used.

** The Point Beach PSA updated value of 2.12E-3 was provided to the NRC on September 12, 1994. The value used for the Point Beach IPE submittal, 8.57E-2, was based on the reliability of the MSIVs prior to the modification of their valve actuators. The value following the MSIV modification, 2.12E-3, is based on the generic reliability of MSIV's.

Substituting the values above into the two cutsets we obtain:

1. <u>IRB-INDUCED-SGTR</u> x <u>MS--MSV-OO-02018</u> x <u>IE-TFB</u> x <u>RECISOLATE-1</u> = <u>CDF</u>
   2.7E-2 x 8.57E-2 x 7.0E-4/yr x 5.0E-2 = 8.1E-8/yr

2. <u>IRB-INDUCED-SGTR</u> x <u>HEP-MS--EOP-3-02</u> x <u>IE-TFB</u> x <u>RECISOLATE-1</u> = <u>CDF</u>
   2.7E-2 x 4.75E-3 x 7.0E-4/yr x 5.0E-2 = 4.0E-9/yr

The total core damage frequency for this sequence would then be the sum of the cutsets which is 8.5E-8/yr.

<u>Steam Line Break Outside Containment, Failure of Main Steam Isolation, Induced Steam Generator Tube Rupture, and Failure to Initiate Low Head Recirculation (Tsb-MS-IR-EC)</u>

The PSA core damage sequence Tsb-MS-IR-EC represents the only steam line break outside containment sequence which was important(i.e., for which cutsets exceeded a frequency of 1.0E-10/year) to the Point Beach PSA core damage frequency. This sequence is made up of the following

cutsets:

1. MS--MSV-OO-02017 x IRB-INDUCED-SGTR x HEP-ECA-EOP31-32 x IE-TSB x RECISOLATE-1
2. MS--MSV-OO-02018 x IRB-INDUCED-SGTR x HEP-ECA-EOP31-32 x IE-TSB x RECISOLATE-1
3. MS--MSV-OO-02017 x IRB-INDUCED-SGTR x HEP-RHR-OP-7A-01 x IE-TSB x RECISOLATE-1
4. MS--MSV-OO-02018 x IRB-INDUCED-SGTR x HEP-RHR-OP-7A-01 x IE-TSB x RECISOLATE-1
5. MS--MSV-OO-02017 x IRB-INDUCED-SGTR x RH--MOV-CC-00700 x IE-TSB x RECISOLATE-1
6. MS--MSV-OO-02018 x IRB-INDUCED-SGTR x RH--MOV-CC-00700 x IE-TSB x RECISOLATE-1
7. MS--MSV-OO-02017 x IRB-INDUCED-SGTR x RH--MOV-CC-00701 x IE-TSB x RECISOLATE-1
8. MS--MSV-OO-02018 x IRB-INDUCED-SGTR x RH--MOV-CC-00701 x IE-TSB x RECISOLATE-1
9. MS--MSV-OO-02017 x IRB-INDUCED-SGTR x RH--MOV-CC-00701 x IE-TSB x RECISOLATE-1
10. MS--MSV-OO-02018 x IRB-INDUCED-SGTR x RH--MOV-CC-00701 x IE-TSB x RECISOLATE-1

The values and descriptions of each of the basic events in the cutsets are provided in the table below:

BASIC EVENT ID	VALUE	DESCRIPTION
IRB-INDUCED-SGTR	2.7E-2	Probability of induced Steam Generator Tube Rupture.
MS--MSV-OO-02017	8.57E-2*	Probability that the Main Steam Isolation Valve 2017 fails to close.
MS--MSV-OO-02018	8.57E-2*	Probability that the Main Steam Isolation Valve 2018 fails to close.
IE-TSB	8.0E-4/yr	Initiating Event Frequency for Steam Line Break Outside Containment.
RECISOLATE-1	5.0E-2	Probability the operator does not take recovery action to mitigate the long term inventory depletion that results from this sequence.
HEP-ECA-EOP31-32	7.70E-3**	Probability the operator does not Cool Down and Depressurize the RCS.
HEP-RHR-OP-7A-01	6.80E-3	Probability the operator does not line up for closed cycle Residual Heat Removal.
RH--MOV-CC-00720	2.58E-3	Probability the RHR return line MOV RH-720 fails to open.
RH--MOV-CC-00701	2.58E-3	Probability the RHR suction line MOV RH-701 fails to open.
RH--MOV-CC-00700	2.58E-3	Probability the RHR suction line MOV RH-700 fails to open.

Notes:

* The Point Beach PSA updated value of 2.12E-3 was provided to the NRC on September 12, 1994. The value used for the Point Beach IPE submittal (8.57E-2) was based on the reliability of the MSIVs prior to the modification of their valve actuators. The value following the MSIV modification (2.12E-3) is based on the generic reliability of MSIVs.

** 7.70E-3 is equivalent to the probability that the operator does not cool and depressurize the reactor coolant system (EC).

Substituting the values above into the cutsets we obtain:

CUTSET #	MSIV FAILURE x	INDUCED SGTR x	RANDOM FAILURE x	INITIATOR FREQUENCYx	RECOVERY=	CORE DAMAGE FREQUENCY
1	8.57E-2	2.7E-2	7.7E-3	8.0E-4	5.0E-2	7.13E-10/YR
2	8.57E-2	2.7E-2	7.7E-3	8.0E-4	5.0E-2	7.13E-10/YR
3	8.57E-2	2.7E-2	6.8E-3	8.0E-4	5.0E-2	6.29E-10/YR
4	8.57E-2	2.7E-2	6.8E-3	8.0E-4	5.0E-2	6.29E-10/YR
5	8.57E-2	2.7E-2	2.58E-3	8.0E-4	5.0E-2	2.39E-10/YR
6	8.57E-2	2.7E-2	2.58E-3	8.0E-4	5.0E-2	2.39E-10/YR
7	8.57E-2	2.7E-2	2.58E-3	8.0E-4	5.0E-2	2.39E-10/YR
8	8.57E-2	2.7E-2	2.58E-3	8.0E-4	5.0E-2	2.39E-10/YR
9	8.57E-2	2.7E-2	2.58E-3	8.0E-4	5.0E-2	2.39E-10/YR
10	8.57E-2	2.7E-2	2.58E-3	8.0E-4	5.0E-2	2.39E-10/YR

The total core damage frequency for this sequence would then be the sum of the cutsets which is 4.1E-9/year.

Conclusion of Core Damage Frequency Increase

The total contribution to the core damage frequency due to induced steam generator tube rupture is the sum of the Tfb-IR-MS and Tsb-MS-IR-EC core damage sequences, which is 8.9E-8/yr. If it were assumed all steam line/ feed line breaks lead to induced steam generator tube ruptures, this contribution would increase to 3.3E-6/year (8.9E-8 ÷ 2.7E-2).

The Point Beach core damage frequency reported in the Point Beach IPE submittal was 1.15E-4/year. This conservative assumption would then result in a change in core damage frequency of about 3% (3.3E-6 ÷ 1.15E-4).

In conclusion, the correct total CDF increase due to induced SGTR with Tfb and Tsb, as of the Point Beach PSA freeze date of September 5, 1990, should be 8.9E-8 (Tfb + Tsb).

Value of EC

EC represents the top event in the event trees for failure of the operator to cool down and depressurize the RCS. This enables the plant to be placed on closed-cycle RHR cooling. This top event (sequence node) has one basic event associated with it. The basic event is HEP-ECA-EOP31-32 and has a probability of 7.70E-3.

2. **(9/19/94) In their response to RAI submittal, the licensee indicated that 25.56% of their total fission product release frequency (FPRF) is due to SGTR. How is the FPRF due to SGTR (6.25E-6) derived? Please provide calculational details (e.g., each sequence term and their probabilities). How does**

the above "error" (in question #1) affect the FPRF due to SGTR? If its contribution to the total FPRF is increased due to the above "error", how much more will it be? Provide calculational justification for this change (as it was done for the two sequences in question #1).

The following are the Steam Generator Tube Rupture (SGTR) sequences, along with their frequencies, and the sum of the sequences, as detailed in our IPE submittal:

Sequence	Frequency	Sequence Terms
R16	1.78E-6	R-AT-AF-MF
R04	1.47E-6	R-MS-EC
R02	1.32E-6	R-OD
R10	1.24E-6	R-AT-EC
R14	2.69E-7	R-AT-AF-MS
R06	9.05E-8	R-SI-OD
R13	5.46E-8	R-AT-AF-OD
R11	3.19E-8	R-AT-SI
Total	6.25E-6	

The sequence terms are defined as follows:

R Steam Generator Tube Rupture as an initiating event

AT Failure of auxiliary feedwater and secondary cooling using the intact steam generator

AF Failure of auxiliary feedwater and secondary cooling using the ruptured steam generator

MF Failure of main feedwater

SI Failure of high pressure safety injection

MS Failure to isolate the ruptured steam generator

OD Failure of the operator action to cool down and depressurize the RCS using the normal EOP-3.1/3.2/3.3 procedures

EC Failure of the operator action to cool down and depressurize the RCS using the ECA-3.1/3.2 procedures

The sequence terms are not individually quantifiable in most cases. In general, each sequence term represents an entire fault tree.

The induced steam generator tube rupture sequences included in our response to the September 9, 1994, request for additional information used core damage frequency (CDF) values of 8.5E-9/yr and 4.1E-9/yr (Tfb-IR-MS and Tsb-MS-IR-EC, respectively). These frequencies were below all four of the PSA reporting criteria as detailed in Table 3.4-1 of the Point Beach IPE submittal. For this reason, these frequencies were not included in the total SGTR CDF value of 6.25E-6. If these sequences had been included,

the resulting CDF due to SGTR would be:

Total IPE SGTR CDF		Original CDF Tfb-IR-MS		Original CDF Tsb-MS-IR-EC		Revised SGTR CDF
6.25E-6	+	8.5E-9	+	4.1E-9	=	6.263E-6, rounded to 6.26E-6

This results in only a 0.2% increase in the overall core damage frequency from SGTRs.

Once the calculation is corrected, as we described in the answer to question number 1, the new frequencies for induced steam generator tube ruptures are:

Sequence	CDF
Tfb-IR-MS	8.5E-8
Tsb-MS-IR-EC	4.1E-9

If these are added to the overall SGTR frequency, the new total is:

Total IPE SGTR CDF		Revised CDF Tfb-IR-MS		Revised CDF Tsb-MS-IR-EC		Revised SGTR CDF
6.25E-6	+	8.5E-8	+	4.1E-9	=	6.34E-6

This is less than a 1.5% increase in the overall core damage frequency from SGTRs.

This increase in SGTR frequency (from 6.25E-6 to 6.34E-6, a 9.E-8 increase) would also increase the fission product release frequency (FPRF) by a like amount, from 2.43E-5 to 2.44E-5. As a result, the revised SGTR contribution to overall FPRF would be 6.34E-6 ÷ 2.44E-5 = 25.98% This is a small increase over the previous value for the FPRF contribution due to SGTR of 25.56%

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