Westinghouse Electric Corporation
Energy Systems

Box 355
Pittsburgh Pennsylvania 15230-0355

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

CAW-94-740

October 14, 1994

Attention: Mr. B. Sharon, Director
Division of Engineering, NRR

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-94-740 and should be addressed to the undersigned.

Very truly yours,

H. Sepp / for
N.J. Liparulo, Manager
Nuclear Safety Regulatory and Licensing Activities

Enclosure

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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 17th day
of October, 1994

Denise K Henderson

Notary Public

Notarial Seal
Denise K. Henderson, Notary Public
Monroeville Boro, Allegheny County
My Commission Expires Oct. 28, 1996
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 9/1/94 REQUEST FOR ADDITIONAL INFORMATION
TECHNICAL SPECIFICATIONS CHANGE REQUEST 175
POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2

1. **How many sleeved tube samples do you intend to pull to confirm the eddy current test methods and results?**

   We do not intend to pull any sleeved tube samples during the upcoming Point Beach Unit 2 refueling outage. We believe that the proposed acceptance criteria contains sufficient margin to account for uncertainties remaining from the lack of pulled tube data. We also feel that the risk involved and the increase in personnel radiation exposure associated with pulling a steam generator tube does not outweigh the perceived benefit of additional information that would be obtained. However, we will continue to assess the need for pulling sleeved tube samples.

2. **Assuming a circumferential flaw, how accurately can the flaw location be determined with respect to the roll transition? In other words, what is the accuracy and repeatability of determining the location of the flaw with respect to some well defined reference point? How accurately and repeatably can the reference points be located?**

   A response was provided at the September 12, 1994, NRC/WEPCO meeting.

3. **How wide is a typical roll transition? Is the width variable depending on whether or not roll-down occurred?**

   The typical roll transition dimension is [ ]^{a,c} long with a nominal length of [ ]^{a,c}. Because of the dimensions of the hard rollers used, the hardroll upper transition is approximately [ ]^{a,c} and the lower transition is approximately [ ]^{a,c}. The width of the hardroll upper transition conforms to the dimension of the roller on the inside diameter (ID) of the sleeve.

   The width of the lower transition would not vary significantly if no [ ]^{a,c} occurred. The length of the transition is dependent on whether or not [ ]^{a,c} occurred. This would also be expected to influence the location of any cracking (assuming the Kewaunee indications to be cracks) that might occur. The important feature relative to strength for a 360° indication is whether or not a significant "lip" exists between the tube and the sleeve in the transition region. In addition, the presence of [ ]^{a,c} would not introduce any locational difficulties.

4. **The WCAP refers to 40% throughwall flaw ligaments in the failure analyses for tubes with throughwall flaw circumferences of 240 degrees. Other material presented to the staff at previous meetings references 60% to 80% throughwall flaw detection sensitivity in the sleeved areas. Discuss the sensitivity and reliability of circumferential crack depth sizing of tubes in sleeved areas, since the 40% figure relates to unsleeved tubes. Reconcile the differences in throughwall flaw detectability and assumed flaw size. Discuss the implications of the 20% to 40% difference in flawed throughwall thickness with respect to the tube failure margin for the throughwall flaw length, i.e., is there any margin for a throughwall flaw if the remaining ligament is 60% or 80% throughwall cracked?**

The WCAP was prepared assuming that the Cecco-3 probe would be used. Information presented indicated a 40% threshold for detection of ID and outside diameter (OD) circumferential indications based on EDM notches with a length of 0.25 inch (~35°) and a width of 0.005 inch. The Cecco-5 probe detection thresholds presented were 50% and 60% for ID and OD indications respectively. The depth sensitivity information presented was for indications in sleeved tubes.

The difference in detection threshold between the Cecco-5 and the Cecco-3 probes is 10% and 20% respectively for ID and OD circumferential indications. The 40% value alluded to is between the circumferential and the axial detection thresholds quoted for the Cecco-3 probe.

If the remaining ligament is assumed to be 60% throughwall cracked, the critical angle calculated to meet the $3\Delta P_{NOP}$ requirement of Regulatory Guide 1.121 is 156°. The critical angle calculated for the $1.43\Delta P_{SLB}$ requirement is 205°. For only 20% of the thickness remaining, there is no critical angle for meeting the $3\Delta P_{NOP}$ requirement, and the critical angle calculated for $1.43\Delta P_{SLB}$ would be 49°. However, these numbers are quite conservative in that they do not account for the [ ]^{a,c}. Additional testing has, in some cases, resulted in pulling the sleeve apart before pulling the tube off of the sleeve.

Tensile testing has shown that tubes with 240° throughwall slits at the top of the hardroll lower transition exhibited ligament failure loads of [ ]^{a,b,c}. Based on the cross-sectional area of the non-degraded ligament the force required for plastic overload is approximately 2900 lb_f, which suggests that actual condition includes a large frictional force component and bending lockup component. Since the locations of ligament failure appeared to remain adjacent to the original top of the transition after completion of the test, the bending lockup component affects the joint strength up to the point when the ligament fails.

After the ligament fails, frictional forces prevent tube/sleeve disassociation. Frictional forces after ligament separation ranged from [ ]a,b,c for the specimens which failed in the ligament. Several specimens with slit locations approximately at the top of the transition to about [ ]a,b,c below the top of the transition failed in the sleeve below the joint at about 8000 lb_f. The slit angles were 240° throughwall. Supplemental tests with the slits located in the hardroll flat area about 3/32 inch above the top of the transition also resulted in failure of the sleeve at about 8000 lb_f.

Keeping in mind the Regulatory Guide 1.121 maximum limit of 2179 lb_f, conditions representative of the proposed acceptance criteria would provide large margins to the integrity requirements.

5. **Is there any data specific to Point Beach showing incubation time for tube crack initiation? Is there any supporting data for the assumed crack growth rates of 25% per year? Are these rates worst case bounding values? If so, do they include the Doel experience?**

There is no Point Beach-specific data showing incubation time for tube crack initiation. In accordance with Technical Specifications requirements, all indications with 40% or greater throughwall degradation were either plugged or repaired.

Westinghouse WCAP-14157 no longer refers to a 25% per year crack growth rate. The growth rate is assumed to be on the order of 45° per year, or approximately 1 μm per hour. Please refer to Section 4.2 of WCAP-14157 for specific crack growth rate information and supporting data.

Relative to outer diameter stress corrosion cracking (ODSCC), these are considered to be worst case bounding values in that they are greater than the upper 95% confidence value for observed growth at another plant that was operating at 614°F. Published data on crack growth rates of Alloy 600, e.g., Bundy & Van Roogen, Yonezawa, Theus, Kim & Van Roogen, and Belgian data, indicate growth rates ranging from 1.8 to 9 mils per month at 590°K (600°F). These translate to 0.022 to 0.11 inch per year, or 3° to 15° per year for the diameter of tubes involved. Thus the rate assumed of 45° per year appears to be conservatively bounding, and could be considered to be a bounding aggregate rate for multiple initiation sites.

The Doel 4 crack growth rate was on the order of 160° to 180° degrees in a year at a temperature of 595°F. The temperature at the hardroll lower transition is more likely to be about half way between the primary side temperature and the secondary side temperature, approximately 530°F (T_{sat}+10°F).

Depending on the activation energy of the material, growth rates on the order of 6% to 14% of, or 7 to 17 times slower than, those observed at Doel 4 could be expected. This assumes that all other factors are equal. However, corrosion testing in magnesium chloride indicates the residual axial stress to be higher on the ID of the tube at the hydraulic upper transition than on the OD of the tube at the hardroll lower transition. Thus, even slower rates at the hardroll lower transition would be expected. The aforementioned rates would correspond to 11° to 25° per year for HEJ sleeved tubes. Thus, the rate of 45° per year appears to bound the Doel experience by a significant margin.

6. Is there any other justification for presence of axial flaws in the hard roll region besides L*? F* and L* included some tube sheet constraint assumptions that would not be applicable to the free span sleeved length.

Axial cracks that extend above the hardroll upper transition would be expected to exhibit leakage during operation. Should extension occur during a steam line break (SLB) the radial preload between the sleeve and the tube may be expected to drive the tip within the hardrolled region of the tube, thus limiting the crack opening area exposed to the primary water and reducing the leak rate relative to a free-span crack.

F* considerations are not judged to be applicable because below the F* distance, degradation of any extent will not affect the integrity of the tube-to-tubesheet joint.

L* simply relies on the axial load carrying capability of the tube to resist the pull-out loads and transmit these loads all the way to the tube-to-tubesheet weld if necessary. Similarly, the pull-off resistance of the tube on the sleeve will not be degraded if there is tube material below the transition capable of carrying the applied load. Testing is planned to determine whether or not axial cracks that extend below the hardroll lower transition extend if the tube is pulled off of the sleeve. Assuming that a COD of ~40 mils (perhaps ~50 mils for a 7/8 inch tube) is needed to extend the crack, it is likely that the crack will not extend.

7. Since the pull-out tests were conducted in air, is there any information on the lubricity of water and the resultant pull-out forces that might be expected when the joints are wet?

The hydraulic proof tests are performed such that the joint would be expected to be wetted as in-service relative to the primary side of the tube. Since failure would progress from the top down this would allow wetting to progress if it is a factor. The proof testing has demonstrated pressure capability on the order of $3\Delta P_{NOP}$. In actuality, there could

be expected to be some oxidation of the interface due to the operating exposure, which would likely increase the coefficient of friction between the sleeve and the tube. There is no specific friction data available.

Tensile testing was performed in air at 600°F. The structural model of WCAP-14157 includes only 300 lb_f of frictional effects that subtract from the $3\Delta P_{NOP}$ end cap load of 2179 lb_f. This 300 lb_f value represents the first slip, or breakaway condition of conservatively performed tests which simulated a 360° circumferential separation of the parent tube in the hardroll flat area slightly above the top of the hardroll lower transition. The structural model does not include any further interference condition allowance. Therefore, the lubricating effects of water in the tube/sleeve interface are independent of the assumptions used in the structural model.

Hydraulic proof testing of specimens with 240° throughwall slits located at the top of the hardroll lower transition indicated that the joints remained entirely intact at proof pressures of [ ]^{a,b,c}. These tests were performed at room temperature. Leakage through the joint limited the maximum pressure obtainable. Only in the case of the specimen which experienced a proof pressure of [ ]^{a,b,c} was any effect noticed upon the specimens. The slit angle for this specimen was observed to have opened by about 0.01 inch, from 0.02 initial width. The overall length of the specimen was unaffected. Based upon the area affected, the 6800 psi proof pressure equilibrates to an end cap load of approximately 4,100 lb_f, which exceeds the limiting $3\Delta P_{NOP}$ end cap load by greater than a factor of 2, i.e., greater than $6\Delta P_{NOP}$.

8. **What metallurgical examination results are available which demonstrate that the assumed circumferential cracks are just that? How much do the cracks wander out-of-plane or tend to turn into longitudinal cracks?**

Since no tubes have been pulled, there are no metallurgical examination results to discuss. Thus, the assumed circumferential cracks may not be cracks. Assuming the indications to be circumferential cracks is considered to be conservative in the absence of any other data.

There is no direct information regarding the wandering of the cracks out-of-plane. This is based on interrogation of the "I-coil" and "3-coil" RPC information available from the Kewaunee inspections.

Even with roll-down present, the transition would not be expected to exhibit waviness of any significant extent. Cracks would be expected to be driven by the maximum principle tensile stress, and this should occur in a specific plane of the transition.

RESPONSE TO 9/7/94 REQUEST FOR ADDITIONAL INFORMATION
TECHNICAL SPECIFICATIONS CHANGE REQUEST 175
POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2

1. **Although the consequences of an assumed leak rate are determined, the risk associated with tube failures under the alternate repair criterion is not discussed. Provide an integrated risk assessment for events that could lead to tube failures and resulting core damage assuming operation under the proposed repair criteria. The assessment should estimate the level of risk created by the potential for steam generator tube rupture to lead to core damage given the allowed conditions of the tubes under the proposed criterion. The response should include, but not be limited to, initiating event frequencies, induced tube failure probability for the conditions related to the particular event, and the estimated probability of event mitigation to prevent core damage. Include an assessment for induced multiple steam generator tube ruptures.**

An integrated risk assessment has been performed of the change in the risk of core damage associated with steam generator tube failures due to the use of alternate repair criteria for circumferential crack indications in sleeved tubes. This assessment was based on a review of the impact of the alternate repair criteria on the results of the core damage frequency reported in the Point Beach Nuclear Plant Individual Plant Examination (IPE) for Severe Accident Vulnerability, June 1993. A Level 1 (internal event analysis) and Level 2 (containment and source term analysis) Probabilistic Safety Assessment (PSA) was used to perform the PBNP IPE. The results indicate a total estimated core damage frequency (CDF) for either Point Beach unit from internal events (including internal flooding) of 1.15E-4/year (see attached Figure 1.4-1 from the IPE Submittal showing PBNP Core Damage Frequency by Initiator). The estimated fission product release frequency (FPRF) is 2.43E-5/year with a roughly 25% contribution from Steam Generator Tube Rupture (SGTR) sequences, which can bypass containment to the atmosphere via the ruptured tube and SG safety or steam dump valves (see attached Figure 1.4-2 from the IPE Submittal showing PBNP Fission Product Release Frequency by Containment Challenge Cause).

PSA Initiating Events Affected by SG Tube Failure

All of the PSA initiating events were reviewed for the impact of the newly-identified degradation mechanism and the proposed alternate repair criteria for sleeved SG tubes at Point Beach Unit 2 (see attached Tables 3.1.1.A-13 and 14 from the IPE Submittal showing initiating event categories and frequencies). It was determined that the initiating event frequency used in the PSA for Steam Generator Tube Rupture (SGTR) events and the probability of induced SGTRs following

steam line break (SLB) or feedwater line breaks (FLB) events could be impacted by the proposed criteria. The SLB and FLB events are believed to be the only PSA initiating events which lead to rapid depressurization of the steam generators. Rapid depressurization results in a sudden increase in delta-P across the steam generator tube and sleeve walls leading to increased hoop and axial stresses with a significantly increased potential for induced SGTRs.

The Oconee transient event of August 10, 1994, which resulted in rapid depressurization of one of the B&W-designed, once-through steam generators was also considered for applicability to Point Beach. This type of transient has the potential to lead to rapid depressurization of the secondary side of a steam generator due to dryout. However, the Westinghouse-designed recirculating, U-tube steam generators used at Point Beach contain a large inventory of secondary water at close to saturation temperature. This water inventory would tend to maintain secondary side pressure close to or above the normal secondary side pressure for long periods (~30 minutes or more compared to about one minute in the B&W design) following a transient event such as loss of feedwater flow, leaking safety valve, or inadvertent opening of an atmospheric or condenser steam dump valve. The large amount of time available to prevent dryout at Point Beach for these transients allows time for operator action to isolate the SG or to cooldown and depressurize the RCS to minimize the dP across the steam generator tubes. Therefore, induced tube ruptures from transients or initiating events other than SLB or FLB are not considered credible at Point Beach.

<u>Impact on SGTR Core Damage Sequences</u>

There is a potential that the newly discovered degradation mechanism for sleeved SG tubes and the associated proposed alternate repair criteria could impact the initiating event frequency for the SGTR event. The SGTR initiating event frequency for the Point Beach PSA is currently calculated based on the tube rupture history for Westinghouse steam generators. As of October 1, 1991, there were 7 tube rupture events in 6.86E6 tube-years of operation of domestic Westinghouse steam generators. Using 6,423 total unplugged tubes in the Point Beach Unit 1 steam generators (Unit 2 had only 6016 unplugged tubes at that time, so the Unit 1 number was used in the PSA) yields:

F[illegible]a(SGTR) = (7 ruptures/6.86E6 Tube-Years) X 6423 Tubes

= 6.55E-3 Ruptures/Year

Note that this frequency does not take credit for the improved water chemistry controls, the SG cleaning activities (e.g., sludge lancing and crevice flushing), and the improved surveillance techniques instituted over the past 20 years, so this number is conservative.

Westinghouse SG tube sleeves have been in service for over 10 years. These sleeves were first installed in the Point Beach Unit 2 Steam Generators in 1983. Since there have been no ruptures of sleeved tubes in the sleeved region in any Westinghouse SGs, it will be assumed that one rupture in a sleeved tube due to the newly discovered degradation mechanism is imminent or has occurred. Note that this is commonly used PSA technique to calculate failure or initiating event probabilities, when no failures or events have occurred:

Fnew (SGTR) = (8 ruptures/6.86E6 Tube-Years) X 6423 Tubes

= 7.49E-3 Ruptures/Year

This assumption would result in a 14% increase in the SGTR initiating event frequency over the original PSA value. Since the mitigating systems would respond the same to this new type of failure mechanism, the core damage frequency for SGTR initiators would also increase 14% from 6.25E-6/year to 7.15E-6/year. This increases the total internal events CDF for Point Beach by less than 1% from 1.15E-4/year to 1.16E-4/year. This is not a significant increase and the proposed alternate repair criteria is not expected to result in even one additional tube rupture, so this result is conservative.

Impact on SLB/FLB Core Damage Sequences

For the FLB and SLB accidents, the initiating event frequencies from the Point Beach PSA are 7E-4 for steam line break/feed line break inside containment (Tfb) and 8E-4 for steam line break outside containment (Tsb). Note that there have been only two feed line breaks and no steam line break events in over 1370 reactor-years of domestic Westinghouse pressurized water reactor operation. There is only one core damage sequence each from the SLB and FLB initiating events resulting in a core damage probability above the 1.0E-10 cutoff frequency used in the Point Beach PSA (see attached event trees for Tfb and Tsb from Figures 3.1.2-7 and 8 of the IPE Submittal). These two sequences (Tfb-IR-MS at 8.5E-9/year and Tsb-MS-IR-EC at 4.1E-9/year) both include an induced steam generator tube rupture (IR) and a steam generator isolation failure (MS). The probability of SG isolation failure (MS) used in the Point Beach PSA was 2.12E-3. The induced steam generator tube rupture probability (IR) used in the Point Beach PSA is 2.7E-2 for an unisolated, faulted steam generator. Note that this applies to the induced rupture of a single tube. This is based on NUREG-0844 and NUREG/CR-0718 for the thinned tube population at Point Beach conservatively assuming 2600 psid across them following a SG blowdown. An unisolated, faulted steam generator is assumed to completely depressurize, which would increase the dP across the tubes from roughly 1200 to 2000 psid (assuming the operators maintain RCS pressure at or below the Point Beach normal operating pressure of 2000 psig).

In the NUREG-0844 study, the principle mechanism for tube rupture is considered to be tube thinning to the point that a tube cannot withstand normal operating stresses. Induced tube rupture during a steam line (or feed line downstream of the main feed check valves) break is due to the increased dP across the tubes during the blowdown transient. The basis of the probability calculation (Ref.: NUREG/CR-0718) was that if the wall thins to 88% of its original thickness, it will rupture at normal operating differential pressure. For the steam line break transient, the tubes require 74% of original thickness to remain intact at 2600 psid. Any time during plant life, all of the tubes that have thinned between 74% and 88% of original thickness are susceptible to an induced rupture in the event of a steam line break. The conditional probability of induced rupture was calculated based on NUREG/CR-0718, which used historical data from the late 1970's for Ginna, Prairie Island, and Point Beach, which each had each experienced a tube rupture event at the time the study was done. The NUREG stated that these plants had operated with tubes in the 74 - 88% thinned window of vulnerability for 2.7% of the plant life.

Based on the above information, the core damage frequency for initiator Tfb calculated in the Point Beach PSA for the one induced steam generator tube rupture sequence above the cutoff is 8.5E-9/year. The core damage frequency calculated for initiator Tsb for the only induced steam generator tube rupture sequence above the cutoff is 4.1E-9/year. Therefore the total core damage frequency due to induced steam generator tube rupture following a steam line/feed line break at Point Beach is 1.26E-8/year.

Mitigating systems reliability will not be affected by a change in frequency in the induced single tube rupture probability. Therefore, a bounding risk assessment of the impact of the proposed alternate repair criteria was performed by simply increasing the induced tube rupture probability (IR) from 2.7E-2 to 1.0. Using this conservative value of IR, the CDF due to induced tube ruptures would go to 1.26E-8/year X 1.0/2.7E-2 = 4.67E-7/year or an increase of 4.54E-7/year (i.e., 4.67E-7 - 1.26E-8/year). The resulting increase to the total internal events CDF calculated in the original PSA of 1.15E-4/year is only 0.4%, which is not significant.

Induced Multiple SGTRs

The NRC staff reviewed the risk associated with the potential for inducing the rupture of multiple SG tubes in their safety evaluation of License Amendment 50 for Commonwealth Edison's Braidwood, Unit 1, August 26, 1994. The staff estimated the probability of bursting two SG tubes and three SG tubes following a steam line break with rapid depressurization of the SG. For induced rupture of two SG tubes at beginning of cycle (BOC) the probability was 6.5E-4 and for bursting three SG tubes the probability was 9.8E-6. The estimated

probability for a single SG tube at BOC was estimated by the licensee as 3.1E-2 (compared to our estimate of 2.7E-2). The staff's conclusion was that risk is dominated at BOC by the failure of a single SG tube and that this conclusion likely applies at the end of cycle as well. Wisconsin Electric agrees with this conclusion and believes it applies to Point Beach. In addition, the primary mitigating system for tube rupture is the safety injection system. The design flow of a single SI pump is 700 gpm, whereas the expected break flow from a single ruptured tube is expected to be roughly 350 gpm. The mitigating system failure probabilities calculated in the PSA for a single tube rupture, therefore, should also apply to a rupture of at least two tubes (i.e., 700 gpm), but probably not three tubes. The probability of induced rupture for three tubes, however, is more than three orders of magnitude lower than for a single tube. Therefore, the risk of multiple induced tube rupture core damage sequences is expected to be below the PSA cutoff threshold of 1.0E-10 and certainly below the generally accepted "safety concern" level of 1.0E-6/year core damage.

Summary and Conclusions

As discussed above the only Point Beach PSA initiating events affected by the newly discovered SG tube degradation mechanism and proposed alternate repair criteria are the steam generator tube rupture (SGTR) and steam line and feed line break for core damage sequences containing induced SGTR. Using a conservative bounding risk assessment for these events, it was determined that the PSA-calculated internal events core damage frequency for Point Beach of 1.15E-4/year was only increased less than 1% for SGTR and less than 0.4% for the induced SGTRs following a SLB/FLB. In addition, it was concluded that single tube ruptures dominate this small risk, so that multiple tube ruptures are not a concern. Therefore, this integrated risk assessment concludes that the proposed alternate repair criteria does not pose a significant additional risk of core damage for Point Beach.

2. **Identify other design basis events which would subject the tubes to high primary to secondary differential pressures, such as steamline break and spurious opening of steam bypass or atmospheric dump valves. Relying on analytical studies and operational data, identify the maximum pressure differentials that would occur.**

In addition to a postulated steam line break event or spurious opening of a safety valve, the following moderate frequency accidents:

1) uncontrolled rod withdrawal from full power,
2) loss of reactor coolant flow,
3) loss of load, and
4) loss of normal feedwater

would result in higher than normal primary to secondary pressure differentials across the steam generator tubes.

The maximum pressure differential across the tubes that may be experienced for steam generator loss of secondary side pressure events is 2560 psid. For items 1) through 4), the maximum pressure differential across the tubes would be expected to be less than 1800 psid.

3. **Provide information which addresses the probability of crack nondetection. Evaluate how the probability may vary with repeated tests and with crack location. Also analyze and describe the impact of nondetection of cracks in the hardroll area and the lower transition region. The accident analysis needs to be included to show that, with undetected and detected cracks in the lower transition, and with undetected cracks in the hardroll, that 10CFR100 is not exceeded for the most limiting DBA, and that ten percent of 10CFR100 is not exceeded for the most limiting transient. How many tubes can be expected to separate for these events?**

Laboratory testing of Cecco 3 and Cecco 5 EC probes demonstrate adequate sensitivity to circumferential EDM notches at the 40% through-wall depth level. It is expected that this performance level applies also to stress corrosion cracks, based on the relative performance of these probes on available cracks with metallographic results. Therefore, it is expected that undetected cracks need be assumed only below 40% throughwall.

The repeatability of detection of cracks is demonstrated in the Cecco probes' testing data, wherein improved statistics are obtained by rotating the crack specimens between tests. This provides for detection data for each crack or notch by a different sensing element with each test. This effect is implicit in the statistical sampling population from which the detection adequacy is derived. Since all these tests were conducted with the most difficult geometry for detection, i.e. ID/OD cracks or note has in the hardroll or hydraulic transitions, there is no expected degradation in sensitivity of detection for less stringent geometries or locations.

It has been shown in previous presentations that the limits of 10CFR100 will not be exceeded with undetected cracks in the lower hardroll transition area. Further analysis and testing will be performed to evaluate the impact on nondetected cracks in the upper hardroll transition area.

4. **Due to the lack of information in the submittal, provide supporting discussion and analyses to validate the postulated maximum 2.5 gpm leak rate for tubes machined away at the top of the lower hardroll transition region. This figure is**

important for calculating total leak rates for different accident and transient scenarios. Explain the basis for using 2516 psid to satisfy the burst pressure requirements of Regulatory Guide 1.121.

For the initial evaluation of potential leak rate in the event of severing of the tube, calculations were performed for assumed radial gaps if the tube displaced axially upward relative to the sleeve. For a radial gap of [$]^{a,c}$ the projected leak rate was found to be ~25 gpm. If the tube displacement is limited to less than or equal to [$]^{a,c,e}$, reported in the WCAP as the ~95% confidence value for tangent point contact, the lower end of the hardrolled region of the tube would still be in contact with the upper end of the hardrolled region of the sleeve. For leakage purposes, it was assumed that a gap on the order of [$]^{a,c}$ would be present instead of contact. This is $1/10^{th}$ of the gap for which 25 gpm was calculated, and would thus be expected to leak at a rate of 2.5 gpm.

It is assumed that the reference to 2516 psid is intended to be 2560 psid. Relative to RG 1.121, it is required that the stress limits of the ASME Code, Section III, paragraph NB-3225 must be met for faulted conditions. Paragraph NB-3225 refers to Appendix F limits. Appendix F requires that the applied load shall not exceed 0.7 of the plastic instability load. In practice, the factor of 0.7 is inverted to obtain 1.43, which is then applied to the SLB pressure to obtain 3657 psid as the applied load. This is then compared to the plastic instability load. The value of 2560 psid originates from a system predicted pressure of 2500 psia. A 3% accumulator margin is applied and the atmospheric pressure is subtracted to obtain 2560 psid. For a 7/8" diameter tube the axial load under SLB conditions is 1208 lb_f which for RG 1.121 considerations becomes 1727 lb_f. RG 1.121 also requires a margin of three against burst during normal operation conditions. This results in comparing an applied load of 2179 lb_f to the plastic instability load in the absence of any other load carrying considerations. The original intent of the RG was to verify that margins similar to those of the ASME Code for the design of components would exist. Following this intent, the $3\Delta P$ load should only be compared to analytical results. This is because a tube specifically designed for the $3\Delta P$ load will actually burst at a pressure of $\sim 2.5\Delta P$ if tested.

5. **The application proposes that the operational leakage limit be reduced to 150 gpd, but the ability of existing primary-to-secondary leakage detection means to respond to this level of leakage is not discussed. Describe the leakage monitoring systems in use in terms of sensitivity, monitoring point, indications available, and instrument set points. Sensitivity**

should be characterized by the minimum detectable primary-to-secondary leakage levels, the response time of the instruments, and the delay involved from instrument leakage response to indication available to the operators in the control room. Also discuss the ability of the monitoring methods to differentiate the leaking steam generator as well as the ability to furnish leak rate trending information to the control room operators.

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 x 10 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)

2) Common (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 steady state
- 40 gpd

If steam generator tube leakage is greater than 40 gpd, the alert setpoint is 15 gpd above the 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.

6. **Another area that is not included, but is required in the licensee submittal, is analysis to demonstrate that plant procedures can adequately terminate single and multiple tube**

ruptures or significant leaks induced by a main steamline break. Describe any changes that have been made to accommodate the new plugging criteria.

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.

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

1) Once per shift, Operations reviews the 24 hour trend 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."

PBNP Action Levels:

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, 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.

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.

Based on simulator exercises performed by 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 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. We also evaluated NRC Information Notice IN 93-56, "Weakness in Emergency Operating Procedures Found as Result of Steam Generator Tube Rupture," and identified no deficiencies.

No changes to mitigation procedures are planned because the AOPs and EOPs are presently intended to mitigate any and all steam generator tube rupture events regardless of the cause mechanisms.

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.

7. **More information is needed to support the claim that maximum tube slippage is about one inch and that tube slips of 3 inches are not possible due to potential contact with other tubes in the U-bend region.**

As part of the development of a plugging criterion for indications within the tubesheet, a study of SG fabrication practices was undertaken. The nominal clearance between tubes at the apex of the U-bend is 0.406". The actual clearance will vary about the nominal due to installation tolerances. The potential contributing factors from manufacturing are:

1. The tube-to-tubesheet fit-up for welding.
2. The tube expansion process.

3. Tube dimensional tolerances on overall length, U-bend radius, tube diameter, etc.
4. Tube trimming to maintain minimum U-bend gaps.
5. U-bend gap adjustment.

The last two operations were not performed on tubes in Model 51 SGs, but are mentioned for completeness. The maximum gap increase in Model 51 SGs resulting from the first three operations was calculated to be [ ]^{a,c,e}. This could occur if a tube was installed such that its U-bend elevation was 0.245" lower than nominal and its outboard neighbor was installed 0.245" higher than nominal. The extremes of the tolerance are taken to be three standard deviations from the mean, i.e., [ ]^{a,c,e}. This means the standard deviation of the clearance would be [ ]^{a,c,e}. The final consideration in the clearance is due to the difference in pressure expansion between the inboard tube and its outboard neighbor. If the inboard tube is assumed to be severed, there will be no elastic strain above the severed end, while the outboard neighbor remained strained due to the internal pressure. The net effect is an apparent increase in the apex clearance of 0.065" during normal operation and 0.136" during SLB. Thus, an upper 95% confidence bound on the apex clearance would be [ ]^{a,c,e} during SLB.

To estimate the maximum upward displacement at the tangent point, it is assumed that the inboard tube deforms into intimate contact with the outboard tube. More extreme deformation would require lateral in-plane deformation which is opposed by the internal pressure. If *d* is the clearance at the apex and *R* is the radius of the U-bend of the inboard tube, the clearance at the tangent point, *D*, is

[ ]^{a,c,e}

Using the upper 95% confidence bounds on the apex clearance results in upper bounds on the tangent point displacement of 1.04" and 1.15" respectively. The expected displacement would be between the two extremes. Taking the average of the apex and the maximum tangent point displacements results in expected displacement limits of [ ]^{a,c,e} respectively for normal operation and SLB at a 95% confidence level. Thus, the maximum expected displacement is on the order of [ ]^{a,c,e}. Since this result is based on a 95% confidence level, it would be expected that the occurrence of multiple tubes achieving this level of displacement would be very unlikely. Referring to the response to Question 4, it would, therefore, be unlikely that more than a few tubes could displace to the extent that the leak rate would exceed 2.5 gpm.

8. It appears that although some testing has been done to measure tube pull forces, an insufficient statistical database is available to have a good estimate of tube pull forces. This uncertainty in the pull force needs to be analyzed and discussed, and also needs to be taken into account to develop a bounding pull force and corresponding differential pressure for tube separation. This data needs to be compared to the differential pressure that the tube would need to withstand for normal operating and accident conditions. Also discuss the difference (either predicted or measured) in pull force between a tube with the minimum remaining ligament and a tube that is completely machined away at the lower transition.

Additional testing has been performed and compared to plastic instability loads calculated as a function of crack angle. For all test cases the limit load exceeded the calculated failure load. The data include a censored test for an arc length of 120°, two tests at an arc length of 180°, six tests at an arc length of 240°, and three tests with the tube completely severed, i.e., 360°.

The testing of tubes which were completely severed and tubes with a remaining ligament also investigated the effect of the elevation of the cut. If the cracks are located at the inflection of the transition or below, the tube can be completely severed and the pull forces will still meet the loading requirements of RG 1.121. If the cracks are at the top of the transition (above the inflection point), some ligament must remain in order to meet the RG 1.121 requirements relative to the pull force. For example, if the remaining ligament is assumed to be 40% cracked, the critical total crack angle to meet the three times normal operating pressure requirement is 224°.

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

1. **The assumed circumferential crack growth mode is by extension of the thru-wall crack tips. Given that SCC can have multiple initiation sites, how can It be assumed, in the absence of pulled tube examinations or other means, that the part thru-wall crack front isn't advancing at the same time the thru-wall portion is growing?**

   Although the discussion of crack growth rates includes information related to growth of the tips of the cracks, the field information referenced, i.e., Kewaunee, plant C and Doel 4, would represent actual performance in a SG environment. Estimated growth rates from this data, which may or may not include multiple initiation sites, is enveloped by the assumed growth rate of 45° per year. Thus, the growth rate of 45° per year represents the sum of growth of the tips and the potential for cracking from additional initiation sites to link with the original crack. Unless the multiple sites are very close together, say, less than 50 mils (approximately the wall thickness of the tube) or ~6°, the tensile strength of the tube may be estimated based on the aggregate length of the cracks.

2. **Please discuss other leak rate testing that has been done for tubes machined away at the top of the lower transition for steam line break pressures. It appears from the WCAP that no tests have been done for this scenario (see WCAP Table 5.2), but this value will be important in determining total primary-to-secondary leak rate during a steam line break. Justify the extrapolation to 2.5 gpm at steam line break pressures.**

   Testing has been performed for tubes machined away at the top of the lower transition. Results from the testing were presented at previous meetings and are included in WCAP-14157. The results of the additional testing were presented at the September 12, 1994, meeting at the NRC headquarters.

   For the initial evaluation of potential leak rate in the event of severing of the tube, calculations were performed for assumed radial gaps if the tube displaced axially upward relative to the sleeve. For a radial gap of [ ]^{a,c} the projected leak rate was found to be ~25 gpm. If the tube displacement is limited to less than or equal to [ ]^{a,c,e}, reported in WCAP-14157 as the ~95% confidence value for tangent point contact, the lower end of the hardrolled region of the tube would still be in contact with the upper end of the hardrolled region of the sleeve. For leakage purposes, it

was assumed that a gap on the order of [ ]^{a,c} would be present instead of contact. This is 1/10th of the gap for which 25 gpm was calculated, and would thus be expected to leak at a rate of 2.5 gpm.

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