PRESENT STATUS AND PROJECTED FUTURE PROGRESSION OF STEAM-GENERATOR TUBE CORROSION/DEGRADATION AT POINT BEACH UNIT NO. 1, WISCONSIN ELECTRIC POWER COMPANY, TWO CREEKS, WISCONSIN

by

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Introduction

Numerous incidents of mill-annealed, Inconel-600 steam generator (SG) tube corrosion/degradation have occurred at Point Beach Unit No. 1. The most important of these are intergranular/stress corrosion cracking above the tubesheet/plate (TS), wastage/thinning above the tubesheet, denting in the tube support plates (TSP), and intergranular/stress corrosion in the tube-tubesheet crevices. These phenomena as they relate to Point Beach Unit No. 1 and other operating steam generators through December 23, 1980 were described and discussed in an earlier report.[1] Tube corrosion/degradation during the first 9.9 years of operation resulted in the plugging of many tubes in both steam generators.

Since December 23, 1980, an additional 68 tubes have been plugged in SG-1A; 31 tubes have been plugged in SG-1B. At the present time, the percentage of tubes plugged in SG-1A and SG-1B are, respectively, 14.4 and 13.2.[2] This represents a significant number of plugged tubes, especially since the Nuclear Regulatory Commission typically prefers to limit the percentage of plugged tubes in a steam generator to about 12.[3]

In order to minimize future corrosion-induced steam generator tube plugging, Wisconsin Electric Power Company (WEPCO) presently operates Point Beach Unit No. 1 at about 77% of full power (thereby reducing the hot-leg temperature from 597 to 557 °F). The corrosion-related benefits of operating at 77% of full power were identified in the earlier report.[1] The benefits in this reduction in the hot-leg temperature were further emphasized when the unit was temporarily operated at 90% of full power (i.e., with a hot-leg temperature of 575 °F); an unacceptably large number of tubes were subsequently plugged because of intergranular/stress corrosion in the tube-tubesheet crevices of both steam generators.

Because it is conceivable that additional steam generator tubes will require plugging in the future, possibly necessitating further reductions from 77% of full-power operation, WEPCO has proposed to replace the two steam generators at Point Beach Unit No. 1.[4] In many respects, the Model 44F replacement steam generators are identical to the original Model 44 units. The replacement steam generators, however, include numerous design improvements to preclude corrosion-related steam generator tube degradation.[5,6] Further, the Inconel-600 tubes in the replacement steam generators will be thermally treated to further mitigate the potential for corrosion. A technical description summary of the steam generator equipment replacement program for Point Beach Unit No. 1 is included in the Appendix.[7]

The purpose of this report is to present the results of an in-depth study regarding the present status of steam generator tube corrosion/degradation at Point Beach Unit No. 1. Concurrently, an attempt is made to predict future tube corrosion/degradation with and without steam generator replacement. Specifically, the study was designed to evaluate the following:

1. The anticipated future performance of the replacement steam generators, with regards to:

   a. Full-power operation using the current secondary-side water treatment and water chemistry control systems.

   b. Tube degradation by wastage, pitting, denting, U-bend cracking, intergranular/stress corrosion, fretting, fatigue, and erosion.

   c. Anticipated tube plugging.

   d. The necessity for condensate polishers and condenser retubing.

2. The anticipated future performance of the existing steam generators with regards to:

   a. The possibility of continued tube degradation at 77% of full power operation.

   b. The possibility of further reductions in power output because of additional tube plugging.

3. The potential need to replace major portions of the total system (e.g., feedwater heaters) in order to mitigate:

   a. Corrosion of equipment other than the steam generators.

   b. Corrosion of the steam generators.

In part, the information required to make these evaluations was obtained from State of Wisconsin/Public Service Commission (PSCW) hearing transcripts and exhibits. Applicable data were also obtained from the U.S. Nuclear Regulatory Commission (NRC); Westinghouse Electric Corporation (WEC), PSCW, and WEPCO personnel; and the technical literature.

Potential for Steam Generator Tube Corrosion/ Degradation at Point Beach Unit No. 1

General

A number of mill-annealed, Inconel-600, steam generator tube corrosion/ degradation problems (of varying magnitude and concern) have been identified in operating pressurized-water-reactor (PWR) power production systems. These are:

1. Wastage/Thinning
2. Pitting
3. Denting
4. U-Bend Cracking
5. Intergranular/Stress Corrosion
6. Fretting
7. Fatigue
8. Erosion

Several of these phenomena, however, are of little or no concern to steam generator operation at Point Beach Unit No. 1. For example, erosion and fatigue are once-through steam generator (OTSG) problems.[8] It is further understandable that thermal fatigue of the steam generator tubes would not be expected to be a significant problem in recirculating PWRs because of their inherent design (i.e., the thermal stresses/strains are inherently relaxed by the U-bends).

The potential for tube degradation by fretting is equally considered to be of insignificant concern to steam generator operation at Point Beach Unit No. 1. This belief is supported, in part, by the observation that there has been no indication of significant fretting damage to any of the tubes in any of the operating Westinghouse Model 44 Series steam generators. Model 44-Series steam generators have operated up to 13 years to date without fretting- type tube degradation; there is no reason to believe that fretting will be a problem in the future.

Based upon these and other considerations, it can be concluded that the existing (and the replacement) steam generators at Point Beach Unit No.

1 can be expected to operate until at least the year 2008 without major concern for tube degradation by either erosion, fatigue, or fretting. The other five forms of tube degradation, however, are potential problems and deserve serious consideration.

Denting

A history of Inconel-600 tube plugging in the steam generators at Point Beach Unit No. 1 is included in the Appendix. Examination of these data reveals that denting has not been a significant problem. A total of only 11 tubes have been plugged because of denting; none have been plugged since September 1978. This is understandable because denting is basically an acid-chloride-related phenomenon.[1,9] Denting is generally associated with PWR units where the condenser-cooling waters contain appreciable amounts of chloride (i.e., where sea or brackish water is used for cooling) and there is significant ingress of cooling water (along with dissolved oxygen) into the PWR secondary-side water because of condenser leakage.

Condenser-cooling water at Point Beach Unit No. 1 contains only a small amount of chloride (about 3 parts per million by weight, ppm).[1] Equally important, condenser tube leakage has not been a serious problem at this operating unit since the fatigue-related, condenser-tube degradation problem was solved in the early 1970s. WEPCO also has a continuous, water-chemistry monitoring program (i.e., cation and/or total conductivity) for the four condenser hotwells, the feedwater, and the steam generator blow-down. Condenser leaks can be rapidly detected and located; the affected condenser can be isolated from the system before any appreciable amounts of relatively-high quality Lake Michigan water can enter the secondary-side water.

Basically, there is no reason to believe that denting-related steam generator tube degradation will be a future problem at Point Beach Unit No. 1. The existing steam generators should operate at least an additional 25 years without significant concern for denting.

Concern for the potential denting problem would be even further reduced if the steam generators were replaced. For example, the tube support plates in the Model 44F steam generators will be fabricated from Type 405 stainless steel instead of carbon steel. Compared to carbon steel, Type 405 stainless steel has significantly improved resistance to the chloride-induced, occluded-cell corrosion which causes denting (Figure 1).(10,11)

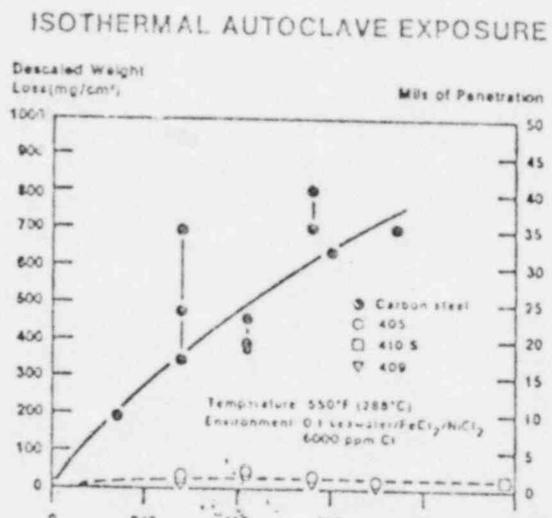

Figure 1 - An unusually-aggressive, simulated-occluded-cell, environment does not cause appreciable corrosion to Type 405 stainless steel in laboratory environments.(10)

The possibility of having chloride-related, occluded-cell tube corrosion in the replacement steam generators will be further reduced by the quatrefoil tube-passage design for the tube support plates (Figure 2).[5] Improved secondary-side water flow at the tube-TSP interfaces will essentially eliminate the occluded cells (i.e., prevent the localized concentrating of chloride ions) which are required for denting.

Based upon these considerations, there should be no concern for tube denting in the replacement steam generators.

There should equally be no major concern regarding the stress-corrosion cracking of the Type 405 stainless steel tube support plates. The material from which the TSPs will be fabricated are delivered to Westinghouse Electric Corporation in the tempered-martensite metallurgical condition.[12] Any prior residual stresses introduced into the material during its production would be eliminated by the 1325 to 1375 °F tempering. Further, the WEC quality assurance program precludes any thermal cutting or welding of the TSPs during their manufacture. Residual stresses introduced into the tube support plates during broaching of the quatrefoil openings will be minimal because of the technique used; broaching is accomplished at ever decreasing amounts of metal removal. In addition, stress-concentrating sharp corners do not exist in the TSP flow slits.

The stress-corrosion cracking of Type 405 stainless steel would be of significant concern only if the yield strength of the material exceeded about 160,000 pounds per square inch (psi), the applied/residual tensile stresses in the material were an appreciable percentage of the yield strength, and the alloy was exposed to an aggressive environment. The tempered-martensite metallurgical structure of the tube support plates for the replacement steam generators at Point Beach Unit No. 1 will not have a yield strength of 160,000 psi, the in-service TSPs will not be subjected to high tensile stresses, and the secondary-side water is not considered to

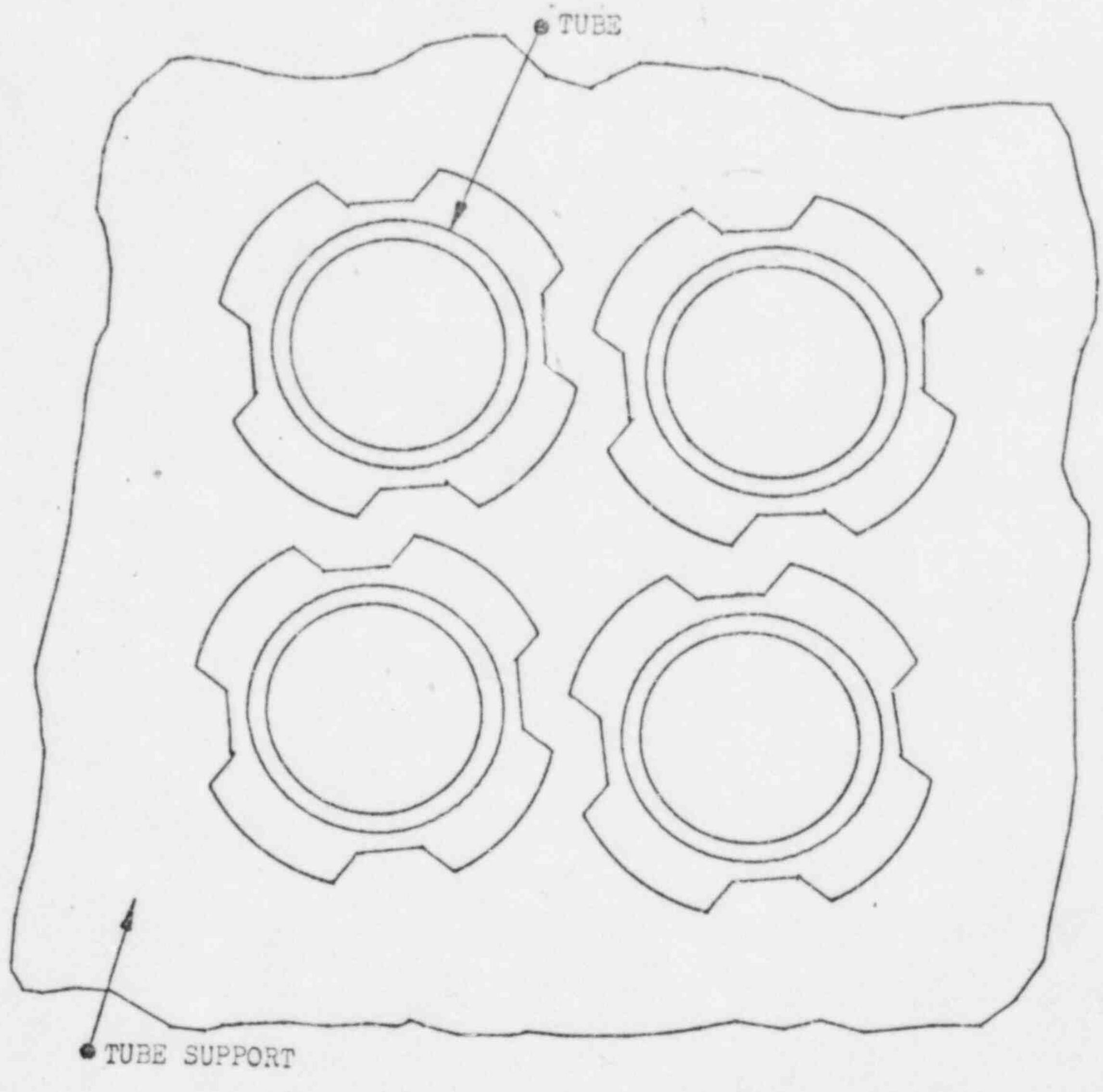

Figure 2 - The quatrefoil-tube-passage design for the Model 44F steam generator TSPs essentially precludes the existence of the chloride-concentrating occluded cells which are required for denting.(5)

to be aggressive. The belief that stress-corrosion cracking of the Type 405 stainless steel TSPs by the secondary-side water is not a problem of concern has apparently been confirmed by extensive testing at Westinghouse Electric Corporation.(6)

U-Bend Cracking

Two possible stress-related causes are believed to be associated with the primary-side-water U-bend cracking which has been observed in the mill-annealed Inconel-600 tubes of certain recirculating PWR steam generators. One of these is denting-related tube support corrosion which causes the TSP flow slots to "hourglass".(9) "Hourglassing" of the flow slots forces an inward displacement of the legs of the tubes at these locations. When this inward movement of the legs of the tubes occurs at the upper tube support plate, it has been shown to cause an increase in the tensile stress/strain at the U-bend apex (i.e., through tube ovalization). This additional increase in the stress/strain at the apex of the U-bend is probably the additional factor required to initiate the cracking.(9)

The other possible factor in the U-bend cracking is residual tensile stresses on the inside tube surfaces which were not eliminated after the bending operation by stress-relief annealing.

Ironically, there have been no known incidents of U-bend cracking in any Westinghouse Model 44-Series steam generators. There should be no major concern regarding this tube degradation phenonenon for the existing steam generators at Point Beach Unit No. 1 during the next 25 years.

The potential for U-bend cracking in the replacement steam generators for Point Beach Unit No. 1 would be further reduced by the improved dentingresistant quatrefoil tube-passage design and the use of highly-corrosion-resistant Type 405 stainless steel for the tube support plates. Further, the U-bends associated with the innermost rows of tubes in the replacement steam generators will be stress-relieved after bending.

Wastage/Thinning

Wastage (tube thinning) of Inconel-600 steam generator tubes is basically a problem associated with PWR units which operate/operated with coordinated-phosphate secondary-side water treatment. The cause of wastage is local concentrations of residual acid phosphates (e.g., phosphoric acid). Since the establishment of all-volatile-treatment (AVT) chemistry control for the secondary-side water, both the evidence and the extent of wastage have been diminished and no further substantial tube degradation due to this mechanism is expected to occur.(9)

No significant number of steam generator tubes have been plugged at Point Beach Unit No. 1 since November 1975 because of wastage. Only 14 tubes have been plugged since November 1975 because of either "wastage or cracking" (see Steam Generator Tube Plugging History included in the Appendix). Regardless of whether the reason for plugging these 14 tubes over a 7.5-year period was cracking above the tubesheets or wastage, the number of tubes involved is considered insignificant; further, the damage was undoubtedly associated with phosphate treatment of the secondary-side water during the early years of Point Beach Unit No. 1 operation.

Based, in part, upon the rigorous tubesheet and crevice cleaning programs which WEPCO personnel have conducted since the conversion to all-volatile secondary-side water treatment in September 1974, there is no reason to believe that future wastage will be a serious problem in the existing steam generators. This belief is supported by the results of extensive eddy-current testing (ECT); there has been no indication that significant additional wastage has occurred in recent years.[2]

With regards to the replacement steam generators, the secondary-side water chemistry will not involve caustic-producing phosphates. It is inconceivable that tube wastage would occur providing reasonable attention is given to control of the secondary-side water chemistry.

Pitting

Only three recirculating-type PWRs have apparently experienced any significant pitting attack on the outside surfaces of the steam generator tubes.[13] A cold-leg phenomenon, pitting should be of concern only if it is anticipated that there will be appreciable ingress of chloride and oxygen-containing, condenser-cooling water into the secondary circuit as a result of condenser leakage.[14] Reportedly, pitting can possibly be facilitated by the presence of sludge and scale containing copper or copper oxide(s).[15]

The results of research by Hickling and Wieling[14] provide significant insight regarding the possibility of Inconel-600 pitting attack taking place in an operating steam generator. Based upon pitting potential/voltage data, it was shown that Inconel-600 might pit over the 300 to 480 °F range providing the secondary-side water contained more than one ppm oxygen in conjunction with a chloride-ion concentration of about 20 ppm.

Since the chemical composition of the secondary-side water (i.e., the condensate, the makeup, and the feedwater) at Point Beach Unit No. 1 are continuously monitored, especially with respect to condenser-cooling water inleakage, the sufficiently aggressive conditions required for pitting should never exist. The inleakage would be detected and its cause corrected long before the conditions apparently required for pitting were created. Further, time is required for pits to initiate and subsequently propagate. The times required for pit initiation are normally reported in units of days or longer.

Concern for steam generator tube pitting at Point Beach Unit No. 1 can be further minimized by appreciating that Lake Michigan water typically contains only about 3 ppm chloride. One-hundred percent Lake Michigan water would have to be concentrated by a factor of about six before it reached 20 ppm chloride; according to Hickling and Wieling's data, this concentrated Lake Michigan water <u>might</u> pit Inconel-600 if the water also contained about one ppm dissolved oxygen. With regards to an operating steam generator, one ppm dissolved oxygen in the secondary-side water would exceed the "free-world's supply." The dissolved oxygen content of the feedwater at Point Beach Unit No. 1 is typically less than 5 parts per billion by weight (ppb).

Based upon these considerations, it can be concluded that pitting should not occur on the outside surfaces of the Inconel-600 steam generator tubes at Point Beach Unit No. 1. The unit should be capable of operating at least an additional 25 years without concern for Inconel-600 pitting attack, either with or without steam generator replacement.

Intergranular/Stress Corrosion

Two, perhaps similar or even identical, intergranular/stress corrosion phenomena have been observed in PWR, mill-annealed, Inconel-600 steam generator tubes. These are intergranular/stress corrosion above the tubesheet and intergranular/stress corrosion in the deep tube-tubesheet crevices which exist in certain older steam generators. Both phenomena are undoubtedly caustic related and associated with units which operated originally with phosphate treatment of the secondary-side water.[1,3,15]

Intergranular/stress corrosion of steam generator tubes above the tubesheet at Point Beach Unit No. 1 is of no major concern at the present time because the deep piles of caustic-containing sludge on the tubesheets have been eliminated by the rigorous sludge cleaning/lancing programs conducted by WEPCO personnel since September 1974. Further, deep sludge piles will not form in the future because condenser-cooling water inleakage into the secondary-side water has been significantly reduced. Sludge-producing phosphates are not used to "correct" inleakage. Inleakage is corrected at its source (i.e., even small amounts of inleakage are readily detected by the continuous chemistry-monitoring system and the cause such as a leaking condenser tube is corrected before any deleterious amounts of Lake Michigan water enter the secondary-side water).

Intergranular/stress corrosion of steam generator tubes above the tubesheet should not be a limiting factor in achieving an additional 25 years of operation at Point Beach Unit No. 1 regardless of the decision to replace or not to replace the steam generators.

Intergranular/stress corrosion of steam generator tubes in the 0.007-inch wide, 19-inch deep crevice which exists at each tube-tubesheet intersection apparently can be controlled by maintaining the hot-leg temperature at a value which does not exceed about 557 °F (i.e., the hot-leg temperature associated with the present 77% of full-power operation). It is obvious that intergranular/stress corrosion is strongly temperature dependent; raising the hot-leg temperature in July 1981 only 18 °F (i.e., to 575 °F) at Point Beach Unit No. 1 subsequently required an unacceptably large number of steam generator tubes to be plugged about eight months later (see Steam Generator Tube Plugging History included in the Appendix).

Since WEPCO's (as well as others') vigorous attempts to completely remove the aggressive (caustic) species from the deep, narrow crevice have not been successful, the steam generator operation at Point Beach Unit No. 1 is destined/limited to a hot-leg maximum temperature of about 557 °F unless the steam generators are replaced. Even at a hot-leg temperature of 557 °F there is no complete assurance that unacceptable intergranular/ stress corrosion will not develop within the next 25 years - - although the results of recent ECT could be interpreted to suggest that it may not. Basically, there are too little long-term data and too many variables to accurately predict the life expectancy for the existing steam generator tubes with regards to intergranular/stress corrosion in the crevices.

The only practical solution to the deep-crevice problem and its inherent intergranular/stress corrosion susceptibility is to eliminate the crevices. This will be accomplished in the replacement steam generators by hydraulically expanding the tubes over the entire tubesheet length. This design change, and others such as flow-distribution baffles above the tube-sheet which will direct any secondary-side sludge/scale to an improved blowdown (see Replacement Steam Generator Equipment Technical Description included in the Appendix), in conjunction with the installation of thermally-treated Inconel-600 tubes should eliminate the possibility of any caustic-induced, intergranular/stress corrosion in the replacement steam generators. The benefits of thermally-treated Inconel-600 steam generator tubes deserve special consideration and are presented in the following section of this report. Briefly, it will be shown that thermally-treated Inconel-600 steam generator tubes have a predicted life expectancy of at least 28 years even if they are exposed to an aggressive caustic-containing environment.

Beneficial Effects of Thermally-Treated Inconel-600

The results of research reported to the technical community in 1973 provided significant insight regarding the beneficial effects of thermally treating Inconel-600.[16] Briefly, Blanchet and his co-workers observed a reversal in the usual sensitizing effect in the intergranular/stress corrosion of Inconel-600 exposed to high-temperature deaerated water. Cracking did not occur in material which had been heat treated to precipitate carbides at the grain boundaries whereas high-temperature annealing (i.e., mill annealing) lead to cracking in the same laboratory environments. Subsequently, considerable research was conducted to more completely understand this metallurgical phenomena and how it might be used advantageously in mitigating intergranular/stress corrosion of Inconel-600 steam generator tubes in pressurized-water reactors.[17-22]

Domian and his co-investigators[17] conducted experiments wherein highly-stressed U-bend specimens of Inconel-600 were exposed to 650 °F, ammonia-hydrazine-treated (AVT), circulating, high-purity water for over 18,000 hours. The results of this research revealed:

1. Intergranular/stress corrosion of Inconel-600 can occur when the grain boundaries are free of carbides.
2. Cracking is predominant in material annealed at temperatures above 1600 °F. Crack frequency increases with increasing grain size.

3. Cracking is reduced by thermal treatments which produce grain boundary carbide precipitation.

4. Cracking did not occur in 18,000 hours for material which had been thermally treated at 1400 and 1500 °F.

5. There was no metallographic evidence of grain boundary carbide precipitation after 13,000 hours exposure at 650 °F.

6. A long incubation period (greater than 13,000 hours) is required for cracking to initiate in highly-stressed material.

Later, Airey's research provided further evidence that thermally-treated Inconel-600 would be advantageous for PWR steam generator tube applications.[18-20] In part, Airey reported the following:

1. For specimens stressed in tension at 50,000 psi and exposed to deaerated, 10% sodium hydroxide (caustic soda) solutions at 600 °F, Inconel-600 which had been thermally treated in the 1200 to 1300 °F range had superior resistance to intergranular/stress corrosion compared to mill-annealed material.[19]

2. Maximum resistance to caustic-induced intergranular/stress corrosion is associated with Inconel-600 which has a semicontinuous, grain boundary carbide precipitate (Figure 3).[18]

3. For plastically-deformed C-ring specimens exposed to deaerated, 10% sodium hydroxide solutions at 600 °F, thermally-treated (15 hours at 1300 °F) Inconel-600 has resistance to intergranular/stress corrosion which can be as much as ten times (or more) greater than that exhibited by the mill-annealed product. (Figure 4).[20]

4. For specimens stressed in tension at values up to 40,000 psi and exposed to deaerated, 10% sodium hydroxide solutions at 600 °F for 4,000 hours, the cracks in thermally-treated (15 hours at 1300 °F) Inconel-600 had propagated only one or two grain depths into the alloy whereas relatively deep cracks existed in the mill-annealed product (Figure 5).[20]

5. For thermally-treated (15 hours at 1300 °F) Inconel-600 specimens stressed in tension at 17,000 to 30,000 psi and exposed to deaerated, 10% sodium hydroxide solutions at 600 °F, the crack propagation rate for intergranular/stress corrosion is so slow that it cannot be meaningfully measured. For mill-annealed specimens stressed at 20,000 psi and exposed to the same environment, the crack propagation rate is approximately 0.050 inch per year (Figure 6).[20]

The early work showing the beneficial effects of thermally treating Inconel-600 has been verified by others.[21] Testing in high-purity water

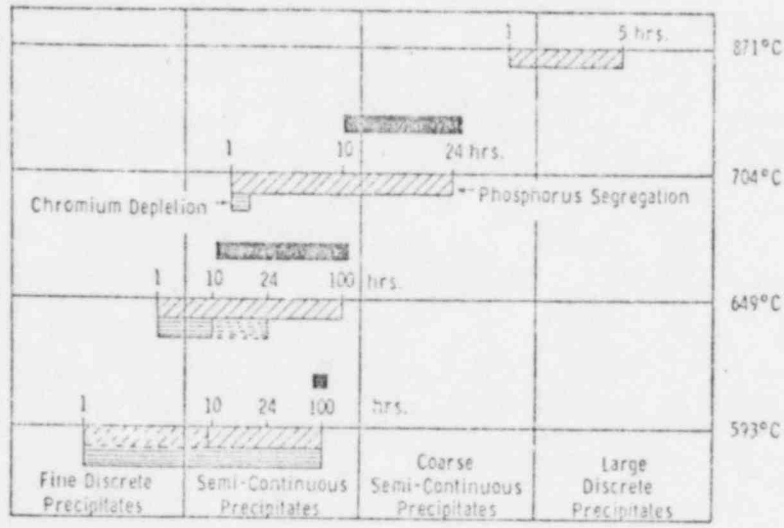

Figure 3 - Summary of grain boundary microstructure in thermally-treated Inconel-600. Dotted lines represent minor grain boundary segregation or chromium depletion. Solid bars correspond to maximum improvement in caustic-induced intergranular/stress corrosion.[18]

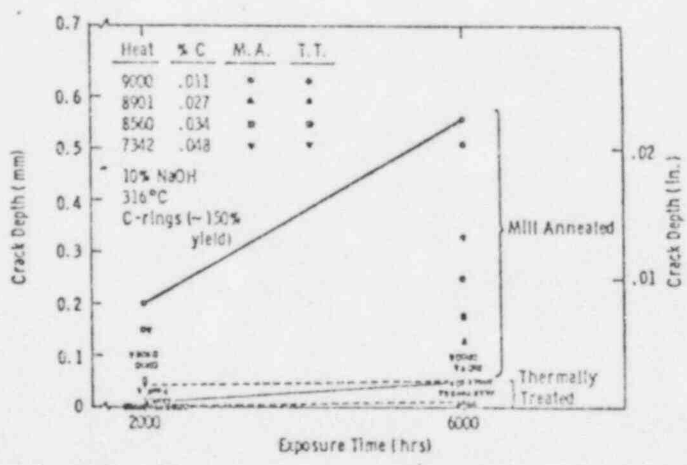

Figure 4 - Crack depth as a function of exposure time for mill-annealed and thermally-treated Inconel-600 exposed to deaerated, 10% caustic soultions at 600 °F.[20]

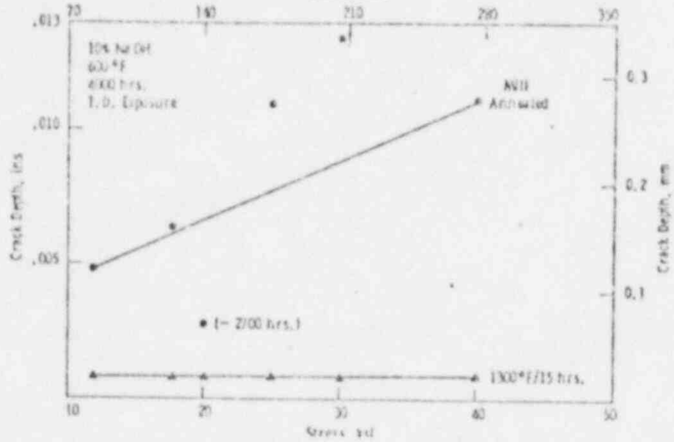

Figure 5 - Crack depth as a function of stress and material condition (i.e., mill-annealed and thermally-treated 15 hours at 1300 °F) for Inconel-600 exposed to deaerated, 10% sodium hydroxide solutions at 600 °F for 4,000 hours.

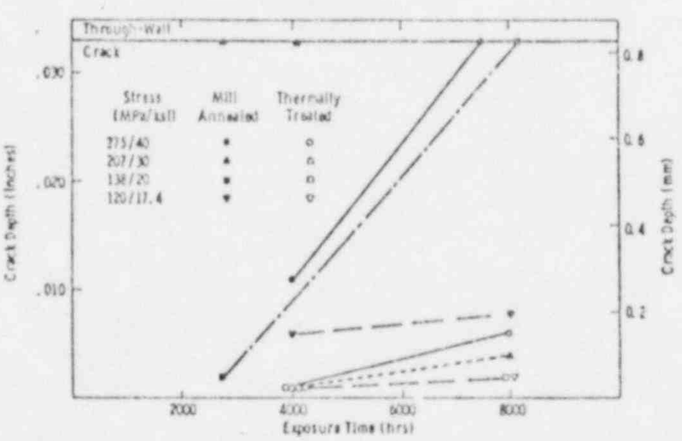

Figure 6 - Crack depth as a function of time, stress level, and material condition (i.e., mill-annealed and thermally treated) for Inconel-600 exposed to deaerated, 10% sodium hydroxide solutions at 600 °F.

containing controlled amounts of dissolved oxygen (0.05 and 8 ppm) at 593 °F, De and Ghosal reported:

1. Highly-stressed, mill-annealed material was cracked intergranularly after 1,600 hours of exposure.

2. Highly-stressed, thermally-treated (24 hours at 1100 °F) Inconel-600 did not experience intergranular/stress corrosion during the 1,600-hour exposure.

3. The beneficial effects of the thermal treatment can be attributed to a semicontinuous-type precipitate in the grain boundaries of the Inconel-600.

The relevance of the 1973-1981 research to the steam generator tube degradation concern can be appreciated from the 1983 results of Airey and Pement who investigated Inconel-600 tube specimens which had been removed from the hot legs of two operating steam generators.[22] They concluded that the most likely aggressive species which causes intergranular/stress corrosion in operating steam generator tubes is caustic.

Analyses of these[16-21] and other data[23] reveal that mill-annealed Inconel-600 can be expected to experience intergranular/stress corrosion in high-purity water, high-purity water containing ammonia and hydrazine, and high-purity water containing sodium hydroxide, providing the environments are sufficiently hot and the specimens are highly-stressed in tension. It can also be seen that highly-stressed but thermally-treated Inconel-600 has significantly improved resistance to intergranular/stress corrosion in these elevated-temperature environments.

The relative improvement in the intergranular/stress corrosion resistance of thermally-treated Inconel-600 is evident from the data presented in Figures 5 and 6. Assuming thermally-treated Inconel-600 is stressed in tension at 20,000 psi and continuously exposed to deaerated, 10% sodium hydroxide solution at 600 °F, the cracks would be expected to propagate no more than one or two grain diameters/depths into the alloy (i.e., about 0.002 inch) in 8,000 hours. For comparison, the cracks in mill-annealed Inconel-600 exposed to the same tensile stress and environmental conditions would be expected to propagate over 0.030 inch in the same time period. Based upon this comparison, thermally-treated Inconel-600 has intergranular/stress corrosion resistance which is at least 10 times that of mill-annealed material.

Since the Point Beach Unit No. 1 steam generators operated approximately seven years before any mill-annealed tubes were plugged because of intergranular/stress corrosion in the tube-tubesheet crevices, the data by Airey suggest that thermally-treated Inconel-600 tubes in the replacement steam generators could have a life expectancy of 70 years at full-power operation (i.e., a hot leg temperature of 597 °F) without concern for intergranular/stress corrosion. Although a 70-year life expectancy for thermally-treated Inconel-600 tubes may appear to be overly optimistic, it must be remembered that it was assumed that the tubes will be exposed to relatively-concentrated sodium hydroxide solution for the entire time period and the cracks do in fact propagate beyond one or two grain depths.

Assuming a safety factor of 2.5 for thermally-treated Inconel-600 stressed in tension at 20,000 psi and continuously exposed to deaerated, 10% sodium hydroxide solution at 600 °F, the life expectancy for the tubes in a recirculating PWR steam generator would be approximately 28 years at full-power operation with regards to intergranular/stress corrosion degradation.

Secondary-Side Water Chemistry at Point Beach Unit No. 1

It is well established that secondary-side water chemistry monitoring/control is at least a major factor in mitigating unacceptable steam generator tube corrosion/degradation. Personnel at both the Electric Power Research Institute (EPRI)[24] and WEPCO[2] fully appreciate this. For example, WEPCO Chemistry Standing Order No. CSO-8 establishes operational and action levels for the feedwater at Point Beach Unit No. 1.[25] Basically, this standing order sets the feedwater pH range at 9.2 to 9.3; the ammonia concentration (as NH_3) range at 0.50 to 0.70 ppm; and the total conductivity range at 4.2 to 5.2 micromhos/cm^3; the feedwater is to contain a minimum hydrazine concentration of 7 ppb. The standing order provides positive direction if any of these limits are exceeded. In addition, WEPCO has (since about 1978) a secondary-side water chemistry monitoring program which is designed to mitigate steam generator tube corrosion/degradation and other system corrosion.[26] It is understood that the existing secondary-side water chemistry monitoring program will be refined in the near future, especially if the steam generators are replaced.[2]

Exactly how well WEPCO personnel have controlled the feedwater chemistry at Point Beach Unit No. 1 can be seen by examining the data in Figures 7 and 8 which are reproductions of actual WEPCO logs for 1983. Excluding the to-be-expected transient conditions, the feedwater during 1983 contained less than 5 ppb (the lower limit of the detection equipment) dissolved oxygen, 7 to 12 ppb residual hydrazine, and 0.5 to 0.7 ppm ammonia; it had a pH of 9.2 to 9.4 and a conductivity of 4.2 to 5.4 micromhos/cm^3. Examination of the 1982 data revealed that the feedwater normally contained less than 5 ppb dissolved oxygen, 0.5 to 0.7 ppm ammonia, and 7 to 15 ppb hydrazine; it had a pH of 9.2 to 9.3 and a conductivity of 4.2 to 5.2 micromhos/cm^3. Similar feedwater data ranges are available for the 1978-1981 time period.

WEPCO personnel have maintained reasonably good control of the AVT secondary-side water chemistry. Secondary-side water chemistry control

WEPCO Chemistry Standing Order No. CSO-8 establishes operational and action levels for the feedwater at Point Beach Unit No. 1.[25] Basically, this standing order sets the feedwater pH range at 9.2 to 9.3; the ammonia concentration (as NH_3) range at 0.50 to 0.70 ppm; and the total conductivity range at 4.2 to 5.2 micromhos/cm^3; the feedwater is to contain a minimum hydrazine concentration of 7 ppb. The standing order provides positive direction if any of these limits are exceeded. In addition, WEPCO has (since about 1978) a secondary-side water chemistry monitoring program which is designed to mitigate steam generator tube corrosion/degradation and other system corrosion.[26] It is understood that the existing secondary-side water chemistry monitoring program will be refined in the near future, especially if the steam generators are replaced.[2]

Exactly how well WEPCO personnel have controlled the feedwater chemistry at Point Beach Unit No. 1 can be seen by examining the data in Figures 7 and 8 which are reproductions of actual WEPCO logs for 1983. Excluding the to-be-expected transient conditions, the feedwater during 1983 contained less than 5 ppb (the lower limit of the detection equipment) dissolved oxygen, 7 to 12 ppb residual hydrazine, and 0.5 to 0.7 ppm ammonia; it had a pH of 9.2 to 9.4 and a conductivity of 4.2 to 5.4 micromhos/cm^3. Examination of the 1982 data revealed that the feedwater normally contained less than 5 ppb dissolved oxygen, 0.5 to 0.7 ppm ammonia, and 7 to 15 ppb hydrazine; it had a pH of 9.2 to 9.3 and a conductivity of 4.2 to 5.2 micromhos/cm^3. Similar feedwater data ranges are available for the 1978-1981 time period.

WEPCO personnel have maintained reasonably good control of the AVT secondary-side water chemistry. Secondary-side water chemistry control

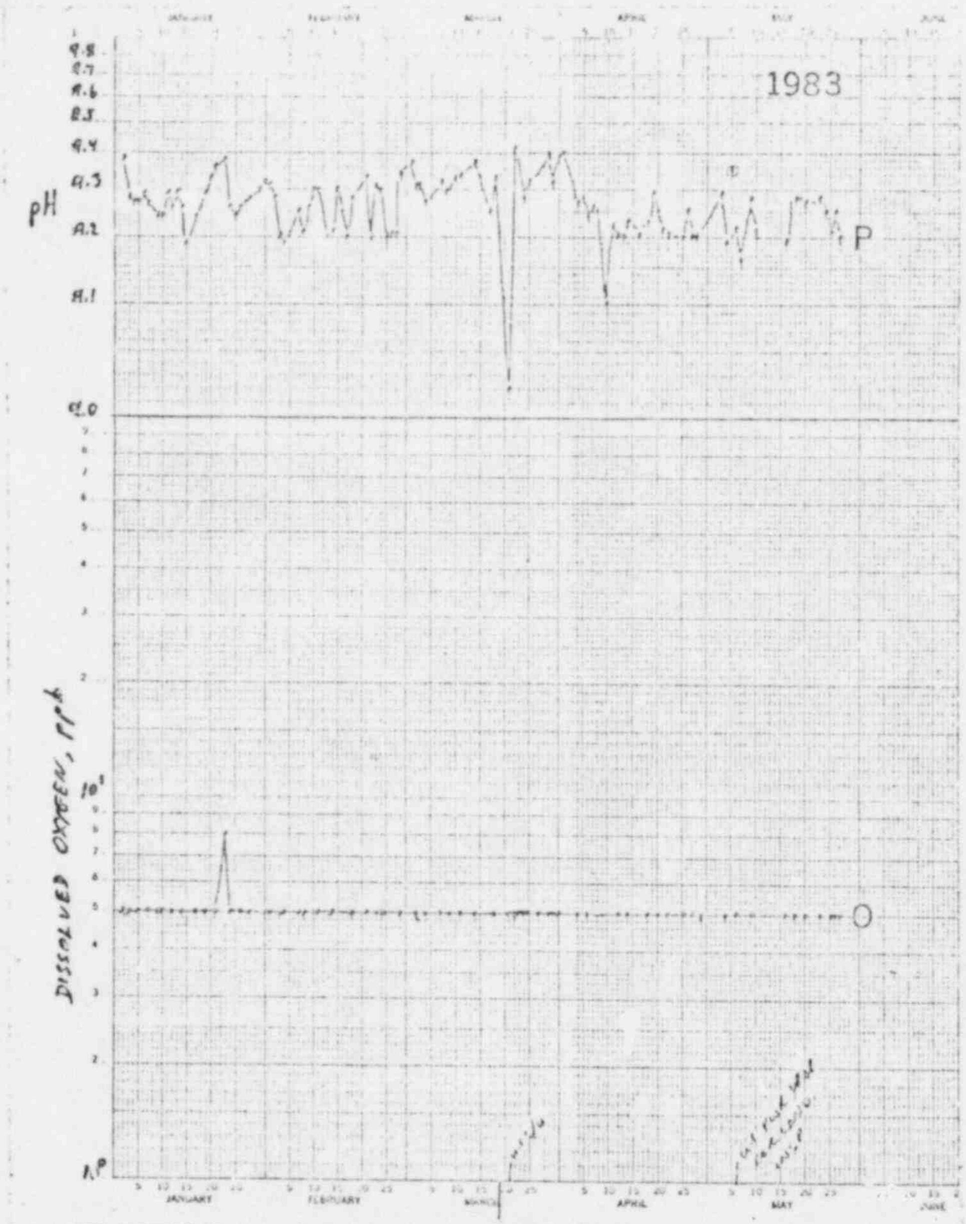

Figure 7 - pH (P) and dissolved oxygen (O) data for the feedwater at Point Beach Unit No. 1 during 1983.

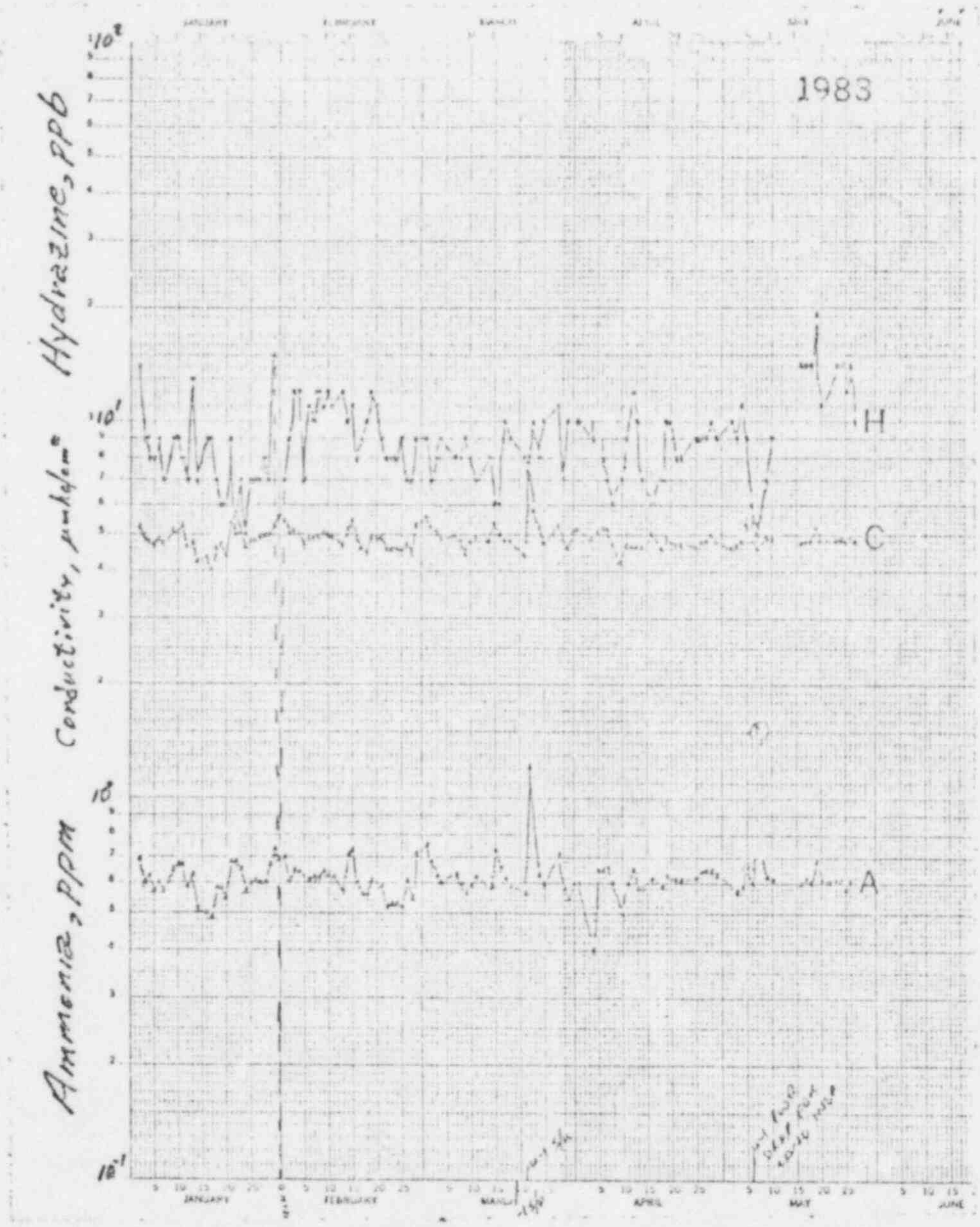

Figure 8 - Conductivity (C), residual hydrazine (H), and ammonia (A) data for the feedwater at Point Beach Unit No. 1 during 1983.

has undoubtedly been somewhat handicapped by the phosphate residues which still exist in the system and a lack of continuous monitoring sites. Very likely, further improvements in the water chemistry monitoring program (e.g., additional continuous monitoring at locations throughout the secondary-side of the system) will be established if the steam generators are replaced.

Anticipated Tube Plugging and Associated Power-Output Reductions for the Existing Steam Generators at Point Beach Unit No. 1

Examination of the Steam Generator Tube Plugging History for Point Beach Unit No. 1 (see Appendix) reveals that the only anticipated, corrosion-related reason for the future plugging of tubes in the existing steam generators would be intergranular/stress corrosion in the tube-tubesheet crevices. The other corrosion-related tube degradation phenomena have been effectively mitigated (Figure 9). Analysis of the intergranular/stress corrosion (crevice) data in Figure 9 between February 1980 and October 1982 provides the only means at the present time of predicting future tube plugging at Point Beach Unit No. 1. Assuming a linear extrapolation of these data on a semilogarithmic plot and allowing a correction factor for the temporary operation at a hot-leg temperature of 575 °F, it can be roughly estimated that an additional 80 to 85 tubes will require plugging during the next 2.5 years of operation (i.e., between June 1983 and December 1985); possibly another 110 to 120 tubes will require plugging between December 1985 and December 1990. It must be emphasized that these predictions are based upon continued operation at 77% of full power with a hot-leg temperature of 557 °F.

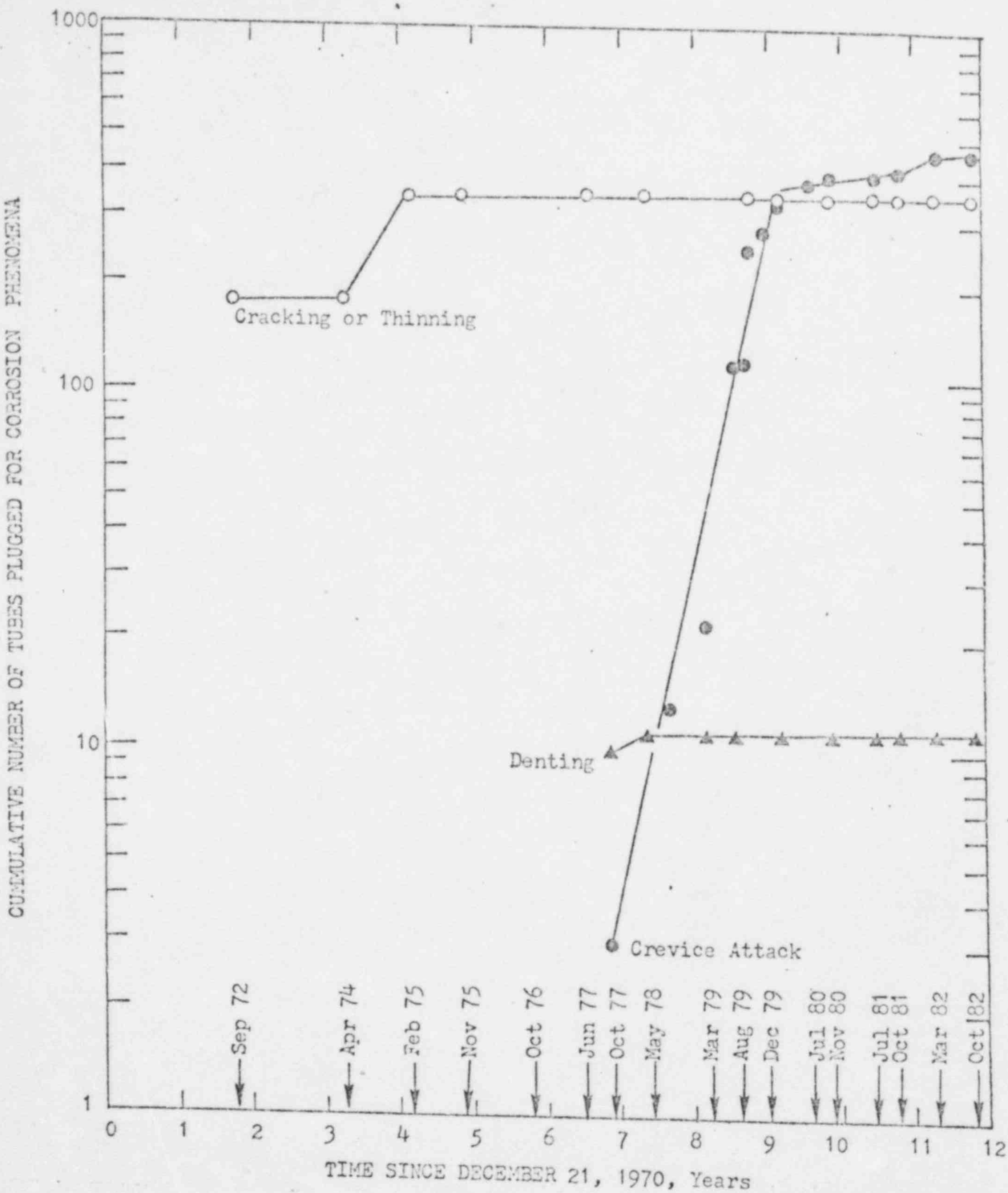

Figure 9 - History of Steam Generator Tube Plugging at Point Beach Unit No. 1. Only intergranular/stress corrosion in the tube-tubesheet crevices is a problem of major concern at the present time.

The need to further reduce the power output (i.e., from 77% of full power) at Point Beach Unit No. 1 because of additional steam generator tube plugging cannot be accurately estimated. Based upon experience, it is reasonable to assume that (after a reasonably large number of tubes have already been plugged) there will be a 0.5 to 0.7 % reduction power output for each additional one percent of tubes plugged.[1] Based upon this hypothesis, the power output by December 1985 could be reduced to about 75% of the full-power rating; by December 1990, the unit could be operating at about 73% of the full power rating.

Necessity for Replacing Equipment at Point Beach Unit No. 1 Other Than the Steam Generators

Deterioration of the 90Cu-10Ni (Copper Alloy 70600) tube interiors in the No. 4 feedwater heaters by general corrosion (undoubtedly ammonia related) has resulted in a large number of tubes being plugged in these units at Point Beach Unit No. 1.(2,27) The tube plugging has resulted in higher water velocities in the remaining tubes and erosion-corrosion damage. Similar deterioration has not been observed in the other feedwater heaters (according to the results of recent tube wall thickness measurements).(2) Very likely, the No. 4 feedwater heater corrosion is a major source of the copper contamination which is occasionally observed in the secondary-side water/sludge.

Replacement of the No. 4 feedwater heaters with units tubed with Type 304 stainless will eliminate both the ammonia-induced general corrosion and the

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[1] Each of the Westinghouse Model 44 steam generators at Point Beach Unit No. 1 contains 3,260 Inconel-600 tubes.

high-velocity-water induced erosion corrosion.

Very likely, the No. 5 feedwater heaters do not exhibit general corrosion because they are tubed with 80Cu-20Ni material (Copper Alloy 71000). The other feedwater heater tubes probably have not corroded to any appreciable extent because they operate at lower temperatures.

There is no obvious reason to replace any feedwater heaters other than those proposed.

It is also known that thermal fatigue has been a problem of concern in the Copper Alloy 70600 moisture separator reheater (MSR) tubes.[2,27] The problem is apparently associated with temperature differentials, uneven tube expansion/contraction, and tube binding.

Replacing the copper-nickel tubes with Type 439 stainless steel, enlarging the tube-support holes, and reducing the tube-support spacing to 25 inches should effectively mitigate the MSR thermal-fatigue problem.

There is no reason to believe that the main condensers should be retubed at the present time. Only about 10 to 12 condenser tubes (out of a total 24,000 condenser tubes) have been plugged each year since the fatigue-related condenser tube problem was corrected in the early 1970s.[28] Consideration should be given to retubing the main condenser only if an unanticipated, unacceptably large number of tubes must be plugged in future years or condenser-tube corrosion is found to be a source of deleterious copper ingress into the secondary-side water. With regards to the latter, the data at Point Beach Unit No. 1 do not suggest that condenser-tube corrosion is a major source of copper contamination. Further, it has not been firmly established that copper is in fact an actual factor in Inconel-600 tube corrosion/degradation.

Necessity for Condensate Polishing at Point Beach Unit No. 1

Mixed success has been achieved with condensate polishing (condensate demineralization) at the operating units which have installed them. There is no reason to believe that they should be routinely installed without question. For example, there were 11 PWR units which had operated over 1,000 effective full-power days (EFPDs) that did not experience a single steam generator tube problem/defect during 1978 and 1979; of these 64% were on AVT, 18% were on phosphate treatment, and 18% were on AVT with condensate demineralization for the secondary-side water treatment.(7) AVT can be a viable chemistry control program for the secondary-side water without condensate polishing.(7,9)

Condensate polishers are basically a desirable option for plants which use sea or brackish water for condenser cooling and/or have a high incident rate for condenser inleakage. Neither of these conditions exists at Point Beach Unit No. 1. Further, there is always concern from resin carryover which could possibly introduce an aggressive species into the secondary-side water when condensate polishers are included in the secondary-side water system.

There is no obvious reason to install condensate polishers at Point Beach Unit No. 1 under the present or anticipated operating conditions.

Conclusions

Based upon the results of this comprehensive, updated study of steam generator tube degradation/corrosion at Point Beach Unit No. 1, it can be concluded:

1. There should be no major future concern for steam generator tube corrosion/degradation by either fretting, fatigue, erosion, pitting,

denting, wastage, U-bend cracking, or intergranular/stress corrosion above the tubesheet with either the existing or replacement steam generators.[2]

2. Continued operation at 77% of full power requires that the hot-leg temperature for the existing steam generators never exceeds about 557 °F.

3. There is reason to believe that some additional steam generator tubes will require plugging because of intergranular/stress corrosion in the tube-tubesheet crevices associated with the existing units. It is believed that future plugging could require the existing units to be operated at about 73 % of the full-power rating by 1990.

4. There should be no significant intergranular/stress corrosion of the thermally-treated Inconel-600 tubes in the replacement steam generators for at least 28 years even if they were continuously exposed to a hot caustic environment.

5. WEPCO personnel have established a reasonably viable secondary-side water chemistry program. They have achieved good success in maintaining the chemistry limits set for the feedwater in 1978.

6. Considerable attention has been given by WEC engineers in the design and materials selection for the replacement steam generators with regards to mitigating the known corrosion problems. Their materials selections is supported by data contained in the technical literature.

7. Replacing the No. 4 feedwater heaters and the MSRs should significantly reduce the amount of copper ingress into the secondary-side water. The stainless steels selected for use in these two systems are considered acceptable for the intended applications.

8. The design changes proposed by the WEC engineers should eliminate the fatigue problem in the existing MSRs.

9. There does not appear to be any obvious reason to replace the No. 5, No. 3, No. 2, or No. 1 feedwater heaters at the present time. Similarly, there is no reason to retube the condenser.

10. It has not been established that small amounts of copper in the secondary-side water have an adverse effect on steam generator tube corrosion/degradation.

11. There is no obvious reason to install condensate polishers (condensate demineralizers).

12. The improved-design replacement steam generators should have at least

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[2] This conclusion assumes 77% full-power operation for the existing steam generators, 100% full-power operation for the replacement steam generators, and proper control of the secondary-side water chemistry.

a 90 to 95% probability of achieving a minimum 25 years of operation at full power providing the AVT secondary-side water chemistry program is refined and rigorously controlled.

13. There should be no significant tube plugging in the replacement steam generators providing the AVT secondary-side water chemistry program is refined and rigorously controlled.

14. At least minor consideration should be given to steam generator replacement in order to preclude the remote possibility of continued corrosion of plugged tubes and the associated potential for foreign object damage (FOD) to nearby unplugged tubes.[13]

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REPLACEMENT STEAM GENERATOR EQUIPMENT
TECHNICAL DESCRIPTION

Wisconsin Electric Power Company will repair the Point Beach Nuclear Plant Unit 1 steam generators by replacement of the present lower assemblies with two Westinghouse Model 44F steam generator lower assemblies and refurbish the primary moisture separator equipment of the present steam generators.

The design objective for the replacement steam generator equipment is to provide the equivalent performance of the equipment being replaced. However, many design improvements are included that are intended to improve the flow distribution, improve tube bundle access, and reduce secondary side corrosion.

The replacement lower assembly includes the following features:

1. A cast channel head will be used. Improvements incorporated will alter the weld preps on the primary nozzles to facilitate inservice inspection.

2. A primary shell drain will be incorporated at the base of the channel head to improve drainage.

3. The channel head support pads will be identical to the present Point Beach design.

4. The tubesheet will be the same dimensions as the previous Series 44 tubesheet. Flush tube-to-tubesheet welds will be used in conjunction with full depth tube expansion for all tubes to eliminate tubesheet crevices.

5. The secondary shell up to and including the transition cone will incorporate additional shell penetrations.

    a. Four six-inch handholes will be placed in the secondary shell just above the tubesheet-to-shell weld seam.

    b. Two additional six-inch handholes will be placed in the stud barrel just above the flow distribution baffle. These openings will be 180° apart and on the tubelane.

    c. One three-inch handhole will be located in the shell at the elevation of the top tube support plate.

6. A welded tubelane blocking device will be installed to limit tube bundle bypass flow. Its design will be such that it shall not hamper sludge lancing.

7. A flow distribution baffle will be placed approximately 18-20 inches above the tubesheet. This baffle will be made of ferritic stainless steel (as will all of the tube support plates). The purpose of this baffle will be to direct the recirculation water across the tubesheet to the center of the bundle. Here any sludge will be deposited in a limited region near the blowdown intake.

8. The tube support plates will have a broached hole pattern using the quatrefoil design. This design has a smaller pressure drop than the most current circular hole designs.

9. The Inconel-600 tubes will be thermally treated. The tube dimensions are 7/8-inch O.D. with 50 mil wall thickness.

10. Increased capacity blowdown will be provided to enhance maintenance of secondary side chemistry. In order to provide this capability, an enlarged blowdown pipe will be provided along with an increased size blowdown nozzle.

11. Tubesheet markings to improve tube identification will be provided on the primary side of the tubesheet indicating the locations of selected tubes. The tenth tube in every row and column will be marked so as to form a 10x10 array of marked tubes.

12. The secondary surface of the tubesheet will be machined to aid in the accurate and uniform definition of tubesheet thickness.

13. The height of the wrapper above the tubesheet will be reduced to improve the flow characteristics near the secondary side of the tubesheet.

14. Downcomer resistance plates will be eliminated to improve the circulation ratio.

15. Drainage holes will be included at the location of the primary manway openings to allow for the drainage of primary water from that area prior to opening of the manways.

16. All tubes in the innermost rows will be thermally stress relieved after tube bending.

17. The leak tightness of the tube-to-tubesheet weld will be confirmed by leak test.

18. The heat transfer characteristics for these units will be the same as the original units.

19. A preservice baseline inspection in accordance with Section XI of the ASME Code will be accomplished after the steam generator has been installed in the coolant loop and a secondary side hydrostatic test has been performed.

In addition to the replacement of the lower assembly, the following modifications to the upper steam drum assembly are included:

1. The addition of a wet layup nozzle to the upper shell designed for a two-inch pipe connection is included.

2. In order to increase the moisture separation capability of the steam generators, the existing primary moisture separators will be changed out to a more efficient separator design. The replacement primary separator package contains swirl vane assemblies attached to an upper and lower deck plate. The primary separator package will be supported off the tube bundle wrapper. The drains from the secondary separator will be enlarged and rerouted through the primary separator assembly. The pattern of swirl vane assemblies requires the installation of a replacement feedwater distribution ring with a different shape than the existing feedwater ring. The feedwater distribution ring will be welded to the feedwater nozzle and supported off the shell. The new feedwater ring will have inverted "J" tubes arranged so that a large portion of the feedwater flow will be directed toward the hot leg side of the tube bundle.

3. A flow restrictor will be installed in the steam outlet nozzle.

4. In addition, the Peerless vanes that comprise the secondary moisture separators will be replaced.

UNIT 1 STEAM GENERATOR
TUBE PLUGGING HISTORY

Date of Outage	Elapsed Time (Years)	Tubes Plugged: Denting A	Denting B	Thinning or Cracking A	Thinning or Cracking B	Crevice Corrosion A	Crevice Corrosion B	Other A	Other B	Total A	Total B	Cumulative Percent A	Cumulative Percent B
12/21/70	0	-	-	-	-	-	-	1[1]	-	1	-	<0.1	0
9/30/72	1.8	-	-	87	91	-	-	14	4[2]	102	95	3.1	2.9
4/6/74	3.3	-	-	1	1	-	-	-	-	103	96	3.2	2.9
2/26/75	4.2	-	-	59	98	-	-	-	-	162	194	5.0	6.0
11/16/75	4.9	-	-	6	4	-	-	-	-	168	198	5.2	6.1
10/1/76	5.8	-	-	-	-	-	-	-	-	168	198	5.2	6.1
6/24/77	6.5	-	-	-	1	-	-	-	-	168	199	5.2	6.1
10/4/77	6.9	10	-	-	-	1	2	-	-	179	201	5.5	6.2
2/1/78	7.1	-	-	-	-	-	-	1[3]	-	180	201	5.5	6.2
5/26/78	7.4	-	-	-	-	-	-	1[3]	-	181	201	5.5	6.2
9/20/78	7.7	1	-	-	-	6	4	-	-	188	205	5.7	6.3
3/1/79	8.2	-	-	-	-	8	1	-	-	196	206	6.0	6.3
8/5/79	8.6	-	-	-	-	52	45	-	-	248	251	7.6	7.7
8/29/79	8.7	-	-	-	-	2	-	2[4]	-	252	251	7.7	7.7
10/5/79	8.8	-	-	2	3[6]	68	61	7	4[5]	329	319	10.1	9.8
12/11/79	9.0	-	-	-	-	19	15	1[7]	-	349	334	10.7	10.2
2/28/80	9.2	-	-	-	1[8]	24	26	-	9[9]	373	370	11.4	11.3
7/26/80	9.6	-	-	-	-	28	22	3[10]	-	404	392	12.4	12.0
11/26/80	9.9	-	-	-	-	3	7	-	-	407	399	12.5	12.2
7/4/81	10.5	-	-	-	1[8]	2	2	-	-	409	402	12.5	12.3
10/9/81	10.8	-	-	-	-	9	7	-	-	412[11]	409	12.6	12.5
3/25/82	11.3	-	-	-	-	37	14	2[12]	-	451	423	13.8	13.0
10/22/82	11.9	-	-	2	4	4	4	12[13]	-	469	431	14.4	13.2

NOTES

(1) Plugged during manufacture.

(2) Fourteen tubes in A were plugged due to gouging during machining for clad repair. Three tubes in B were removed for analysis and one was plugged by mistake.

(3) Plugged tubes were in periphery and were leaking. During the October 1982 outage, these leaks were found to be due to wear by loose parts.

(4) An audit of tubesheet photographs indicated two tubes which were plugged but previously not included in inspection reports.

(5) Seven tubes in A included three with defects less than the plugging limit, two tubes which had no indications but which were pulled for analysis, and two tubes plugged by mistake. Four tubes in B included three tubes with indications less than the plugging limit and one tube plugged by mistake.

(6) Two tubes in A and three tubes in B were plugged due to defects identified at or above the tubesheet using multi-frequency eddy current techniques. These defects are attributed to thinning or cracking in prior years, based upon comparison with single-frequency eddy current results from previous inspections.

(7) One tube plugged by mistake.

(8) One tube in B was plugged due to a defect above the tubesheet which was identified using multi-frequency techniques. This defect is attributed to thinning or cracking in prior years, based upon comparison with results from previous inspections.

(9) Four tubes in B were plugged due to the possibility of being damaged during tube pulling operations and five leaking tubes were plugged without identifying the defect location.

(10) Three tubes plugged by mistake.

(11) One tube which was in excess of the plugging limit was repaired by sleeving. Plugs were removed from six tubes and the tubes were sleeved and returned to service.

(12) Two tubes were leaking and were plugged. Eddy current inspection revealed no indications. One of the tubes was leaking on the cold leg end from which one explosive plug was removed during the sleeving demonstration in 1981.

(13) Twelve tubes include eleven plugged for suspected damage from loose parts in the cold leg and one sleeved tube from which the sleeve was removed for inspection.