# STEAM GENERATOR TUBE INTEGRITY REQUIREMENTS AND OPERATING EXPERIENCE IN THE UNITED STATES

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## ABSTRACT

Steam generator tube integrity is important to the safe operation of pressurized-water reactors. For ensuring tube integrity, the U.S. Nuclear Regulatory Commission uses a regulatory framework that is largely performance based. This performance-based framework is supplemented with some prescriptive requirements. The framework recognizes that there are three combinations of tube materials and heat treatments currently used in the United States and that the operating experience depends, in part, on the type of material used. This paper summarizes the regulatory framework for ensuring steam generator tube integrity, it highlights the current status of steam generators, and it highlights some of the steam generator issues and challenges that exist in the United States.

## 1. INTRODUCTION

Steam generator tubes comprise a substantial portion of the reactor coolant pressure boundary and also play a role in fission product containment. Their integrity is important to the safe operation of a pressurized-water reactor. As a result, there are requirements to ensure that tube integrity is maintained. In the United States, these requirements are performance based and are contained within the technical specifications for each pressurized-water reactor unit. Although there have been improvements in the requirements pertaining to the design and operation of steam generators, tube integrity issues continue to arise. This paper summarizes the regulatory framework addressing steam generator tube integrity and the current status of steam generators in the United States.

## 2. BACKGROUND

There are 69 pressurized-water reactor units in the United States. The number of steam generators at each unit ranges between two and four. These steam generators are of two basic designs: the recirculating, U-tube (62 units) and the once-through, straight-tube (7 units).

The tubing in steam generators in the United States is one of three types: mill-annealed Alloy 600, thermally treated Alloy 600, and thermally treated Alloy 690. Early steam generator designs used tubes fabricated from Alloy 600, which was typically mill annealed by passing the tubes through a furnace to enhance the material's resistance to corrosion. The next generation of steam generators in the United States used thermally treated Alloy 600 tubing. The thermal treatment process further improved the tubes' resistance to corrosion. The third generation uses thermally treated Alloy 690 tubing. This tubing is regarded as more resistant to corrosion than the other tubing material and is currently the material of choice for steam generators in the United States.

As of August 2009, 10 units have mill-annealed Alloy 600 tubing, 17 units have thermally treated Alloy 600 tubing, and 42 units have thermally treated Alloy 690 tubing. Licensees of all 10 units with mill-annealed Alloy 600 tubing plan to replace their steam generators over the next decade, including three units in the fall of 2009 and approximately one unit per year between 2010 and 2017. No U.S. licensees with thermally treated Alloy 600 tubing have announced plans to replace their steam generators.

## 3. REGULATORY REQUIREMENTS

In the United States, all nuclear power plants have technical specifications that licensees are required to follow, and those that address steam generator tube integrity are similar at all pressurized-water reactors. The technical specifications require the development of a steam generator program to ensure that plants maintain tube integrity for the operating interval between tube inspections. The technical specifications define what constitutes tube integrity through the establishment of performance criteria, and the specifications require monitoring primary-to-secondary leakage, performing periodic tube inspections, assessing the condition of the tubes relative to the performance criteria, and defining criteria for plugging tubes [Ref. 1]. The requirements in the technical specifications are largely performance based.

### 3.1 Performance criteria

The technical specifications are considered performance based because they specify performance criteria that ensure adequate tube integrity without specifying the details of how to achieve those criteria. There are three steam generator performance criteria: structural integrity, accident-induced leakage, and operational leakage. Steam generator tube integrity is maintained when all three of these criteria are met, and steam generators can only be operated when tube integrity is maintained. The structural and accident induced leakage performance criteria were based on the design and licensing basis of the plants. The NRC based its operational leakage performance criterion on engineering judgment that considered the need to avoid unnecessary plant shutdowns while limiting the frequency of exceeding the structural integrity performance criterion.

The structural integrity performance criterion requires that margins against tube burst and collapse be maintained during normal operations, transients, and design-basis accidents, including a combination of accidents. The U.S. Nuclear Regulatory Commission (NRC) developed these criteria considering design codes such as that of the American Society of Mechanical Engineers. The actual requirement is as follows [Ref. 2]:

> All in-service steam generator tubes shall retain structural integrity over the full range of normal operating conditions including startup, operation in the power range, hot standby, and

> cool down and all anticipated transients included in the design specification) and design basis accidents. This includes retaining a safety factor of 3.0 against burst under normal steady state full power operation primary-to-secondary pressure differential and a safety factor of 1.4 against burst applied to the design basis accident primary-to-secondary pressure differentials. Apart from the above requirements, additional loading conditions associated with the design basis accidents, or combination of accidents in accordance with the design and licensing basis, shall also be evaluated to determine if the associated loads contribute significantly to burst or collapse. In the assessment of tube integrity, those loads that do significantly affect burst or collapse shall be determined and assessed in combination with the loads due to pressure with a safety factor of 1.2 on the combined primary loads and 1.0 on axial secondary loads.

The NRC has approved some exceptions to these criteria on a unit-specific basis. These relaxations relate to tube repair criteria implemented in plants with mill-annealed Alloy 600 tubes. These relaxations have generally involved adopting a probabilistic criterion for demonstrating tube integrity during accident conditions (e.g., the probability of tube burst, given a steamline break, shall not exceed $1\times10^{-2}$).

The accident-induced leakage performance criterion requires limiting the amount of primary-to-secondary leakage that would occur during a design-basis accident, other than a tube rupture, to that which was evaluated as part of the unit's licensing basis. Demonstrating compliance with the accident-induced leakage performance criterion, therefore, requires a calculation of the amount of leakage expected during various design-basis accidents. The calculated amount of leakage must be less than that assumed in the accident analyses. These particular licensing basis analyses were performed to demonstrate that the radiological consequences associated with these design-basis accidents meet the limits in (1) Title 10 of the *Code of Federal Regulations* (10 CFR) Part 100, "Reactor Site Criteria," for offsite doses, and (2) General Design Criterion 19, "Control Room," in Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities," for control room operator doses; or (3) some fraction thereof, as appropriate to the accident; or (4) the NRC-approved licensing bases. The accident-induced leakage performance criterion is also intended to ensure that licensees maintain the amount of leakage caused by specific severe accident scenarios at a level that will not increase risk. The actual requirement is as follows [Ref. 2]:

> The primary to secondary accident induced leakage rate for any design basis accident, other than a[n] SG [steam generator] tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all SGs and leakage rate for an individual SG. Leakage is not to exceed [1 gpm] per SG[, except for specific types of degradation at specific locations as described in paragraph c of the Steam Generator Program].

As with the structural integrity performance criteria, the NRC has approved some exceptions to these criteria on a unit-specific basis. These relaxations are associated with tube repair criteria implemented in plants with mill-annealed Alloy 600 tubes. These relaxations have generally allowed more accident-induced leakage during steamline break accidents, provided the risk associated with such leakage during specific severe accident scenarios remains acceptable.

The operational leakage performance criterion requires limiting leakage to 150 gallons per day for each steam generator. Although this criterion does not ensure tube integrity, it has been effective in limiting the frequency of tube ruptures and providing an indirect indicator of tube structural and accident-induced leakage integrity. This criterion is important, since it can be monitored while the plant is operating.

### 3.2 Leakage monitoring

The technical specifications require that licensees monitor primary-to-secondary leakage during operation. This specification is performance based, since it does not prescribe how to monitor for this leakage. A related requirement is that licensees must monitor leakage at least every 72 hours. From a practical standpoint, licensees generally monitor for primary-to-secondary leakage continuously and supplement this continuous sampling through periodic grab samples. Most, if not all, plants have leakage monitoring programs that are modeled after the Electric Power Research Institute's "PWR [Pressurized-Water Reactor] Primary-to-Secondary Leak Guidelines—Revision 3," issued 2004 [Ref. 3].

### 3.3 Tube inspections

The steam generator inspection requirements in the technical specifications contain both performance-based and prescriptive elements. From a performance-based perspective, licensees are required to assess the types and locations of flaws to which their tubes may be susceptible, and the inspection method, scope, and the interval between inspections must be sufficient to maintain tube integrity until the next inspection. The performance-based requirements are as follows [Ref. 2]:

> The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube repair criteria. The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements of d.1, d.2, and d.3 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that steam generator tube integrity is maintained until the next steam generator inspection. An assessment of degradation shall be performed to determine the type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

In addition to this performance-based aspect of the inspection requirements, there are also prescriptive inspection requirements. The NRC established these prescriptive requirements to ensure sufficient monitoring of the condition of the tubes. These requirements reflect the improvement in steam generator performance for the various combinations of tube material and heat treatment [Refs. 4, 5]. In addition, the NRC based these prescriptive inspection requirements on qualitative engineering considerations and experience. The prescriptive steam generator inspection requirements in the technical specifications include the following [Ref. 2]:

> d.1 Inspect 100% of the tubes in each steam generator during the first refueling outage following steam generator replacement.
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> d.2 For plants with mill annealed Alloy 600 tubes: Inspect 100% of the tubes at sequential periods of 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the steam generators. No SG shall operate for

> more than 24 effective full power months or one refueling outage (whichever is less) without being inspected.
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> For plants with thermally treated Alloy 600 tubes: Inspect 100% of the tubes at sequential periods of 120, 90, and, thereafter, 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the steam generators. In addition, inspect 50% of the tubes by the refueling outage nearest the midpoint of the period and the remaining 50% by the refueling outage nearest the end of the period. No steam generator shall operate for more than 48 effective full power months or two refueling outages (whichever is less) without being inspected.
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> For plants with thermally treated Alloy 690 tubes: Inspect 100% of the tubes at sequential periods of 144, 108, 72, and, thereafter, 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the steam generators. In addition, inspect 50% of the tubes by the refueling outage nearest the midpoint of the period and the remaining 50% by the refueling outage nearest the end of the period. No steam generator shall operate for more than 72 effective full power months or three refueling outages (whichever is less) without being inspected.
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> d.3 If crack indications are found in any steam generator tube, then the next inspection for each steam generator for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever is less). If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

There have been some modifications to the inspection requirements at some plants. These modifications generally involve specifying inspection requirements associated with tube repair criteria. For example, many of the licensees with mill-annealed and thermally treated Alloy 600 tubes have adopted requirements that limit the extent of inspection in the tubesheet region (e.g., in recirculating steam generators, only the uppermost portion of the tube in the tubesheet is examined, rather than the whole length of the tube in the tubesheet).

## 3.4 Condition monitoring

For a performance-based approach to be effective, licensees must periodically verify that they are satisfying the performance criteria. As a result, the technical specifications require an assessment to confirm that the tubes have adequate structural and leakage integrity. The licensee must perform this assessment during each outage in which the steam generator tubes are inspected or plugged. The requirement is as follows [Ref. 2]:

> Condition monitoring assessment means an evaluation of the "as found" condition of the tubing with respect to the performance criteria for structural integrity and accident induced leakage. The "as found" condition refers to the condition of the tubing during an SG [steam generator] inspection outage, as determined from the inservice inspection results or by other means, prior to the plugging [or repair] of tubes. Condition monitoring assessments shall be conducted during each outage during which the SG [steam generator] tubes are inspected, plugged, [or repaired] to confirm that the performance criteria are being met.

The periodic assessment of the inspection results is a critical element of the performance-based strategy. It requires licensees to assess whether the tubes exhibited adequate structural and leakage (accident-induced) integrity during the prior operating interval. In the event that tube integrity was not maintained, it would indicate the need for corrective action. In addition, it would require reporting to the NRC, pursuant to 10 CFR 50.72, "Immediate Notification Requirements for Operating Nuclear Power Reactors," or 10 CFR 50.73, "Licensee Event Report System." [Ref 6]

### 3.5 Repair criterion (also referred to as "plugging limit")

The repair criterion (historically referred to as the tube "plugging limit") in the technical specifications is prescriptive. At a minimum, all plants have a depth-based tube repair criterion that requires tubes with flaws that exceed a specific size to be removed from service. This criterion is consistent with the performance criteria; however, it may be necessary to remove flawed tubes from service even before they exceed the repair criterion. This may be necessary since the criterion was developed with specific assumptions on flaw orientation, the potential for flaw growth during the next operating interval, and uncertainties in measuring the size of the flaw. Plugging tubes before they exceed the plugging limit may be necessary in instances where longer cycle lengths (than those assumed in the development of the depth-based repair criterion) are anticipated, where the growth rate of the flaws is higher than assumed, and the uncertainties in measuring the size of the flaw are greater. The specific requirement is as follows [Ref. 2]:

> Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding [40%] of the nominal tube wall thickness shall be plugged [or repaired].

Several plants have alternatives to the depth-based repair criterion. These alternatives are only in place in plants with mill-annealed and thermally treated Alloy 600 tubes. These include alternatives that allow tubes to remain in service if all flaws are located in a portion of the tube within the tubesheet and voltage-based repair criteria for flaws at tube support plates.

### 3.6 Implementation issues/clarification of requirements

All pressurized-water reactors in the United States have had the technical specification requirements outlined above in place since September 2007. However, licensees of all pressurized-water reactors had been voluntarily implementing similar "requirements" since the 2000 timeframe.

While adopting and implementing these requirements, licensees identified a number of issues related to the implementation of the accident-induced leakage performance criterion and the tube inspection requirements. As a result, the NRC staff clarified its position on these issues in Regulatory Issue Summaries 2007-20, "Implementation of Primary-to-Secondary Leakage Performance Criteria," dated August 23, 2007 [Ref. 7]; and 2009-04, "Steam Generator Tube Inspection Requirements," dated April 3, 2009 [Ref. 8].

Regulatory Issue Summary 2007-20 clarified the following issues:

- Potential primary-to-secondary leakage for all design-basis accidents should not exceed the value assumed in the accident analyses.

- Accident-induced leakage includes leakage existing before the accident occurred.

- The temperature at which the volumetric primary-to-secondary flow rate (i.e., leak rate) is evaluated should be consistent with the temperature assumed in the accident analyses.

- The assumptions regarding the pre- and post-accident leakage rate must be satisfied.

- The normal operating primary-to-secondary leak rate may need to be kept well below the normal operating primary-to-secondary leak rate limit to ensure the plant does not exceed the accident-induced leakage performance criterion.

- The term “most limiting accident” should be clearly defined (e.g., most limiting, since it produces the largest leak rate, or most limiting, since it is the closest to the regulatory limit on radiological doses).

- In the event that a primary-to-secondary leak rate is not assumed for each steam generator, licensees should institute appropriate controls to ensure the plant does not exceed the accident-induced primary-to-secondary leak rate for all steam generators.

- Exceptions (increases) to the risk-informed 227 liters per hour [1 gallon per minute] limit on accident-induced leakage are evaluated on a case-by-case basis.

Regulatory Issue Summary 2009-04 clarified the following issues:

- In the event that a new potential degradation mechanism is identified after the first inspection in the sequential period, a prorated sample for the remaining portion of the sequential period is appropriate for this potentially new degradation mechanism, rather than inspecting all of the tubes; however, the scope of inspections should be sufficient to ensure tube integrity.

- The starting point for the second and subsequent sequential periods shall be after the accumulation of the effective full-power months listed in the technical specifications (e.g., the starting point for the 90 effective full-power month period is 120 effective full-power months after the completion of the first inservice inspection).

- The inspection nearest the midpoint of the period can either be before or after the midpoint; however, the inspection at the end of the period must take place during an outage before the end of the period.

As a result of some of these issues, the industry recently proposed modifications to the generic steam generator technical specifications (Technical Specification Task Force (TSTF) Traveler TSTF-510, Revision 0, “Revision to Steam Generator Program Inspection Frequencies and Tube Sample Selection,” dated March 26, 2009 [Ref. 9]).  The industry’s proposed modifications are intended, in part, to clarify the intent of the original requirements.  The NRC staff is currently reviewing this request.

## 4. CHALLENGES/ISSUES

Steam generator performance has improved significantly over the last several decades. These improvements, shown by a reduction in the frequency of forced shutdowns caused by primary-to-secondary leakage and a reduction in the frequency of steam generator tube ruptures, are a result of several factors, including the replacement of steam generators and improvements in industry programs.

Although steam generator performance has improved, steam generator issues continue to arise. Some of these issues are plant specific and some are more generic. The issues described below have received recent regulatory attention in the United States.

### 4.1 Degradation of supports at Waterford

Waterford Unit 3 has two recirculating steam generators designed and fabricated by Combustion Engineering. The mill-annealed Alloy 600 steam generator tubes are supported in the vertically straight portion by a number of carbon steel lattice-grid (i.e., eggcrate) tube supports and in the U-bend/square bend region by diagonal bars (also referred to as batwings), and vertical straps. Several of the lattice-grid tube supports are referred to as partial eggcrate supports, since they only support some of the tubes. The tubes in rows 1 through 18 are shaped in a “U” (i.e., U-bend tubes), and the tubes in rows 19 through 147 have two 90-degree-bend regions separated by a horizontal run (i.e., square bend tubes). The length of the horizontal run between the 90-degree-bends depends on the row of the tube. The diagonal bars and the vertical straps are located in the upper bundle region (i.e. the U-bend/square-bend region). The upper end of the batwings is connected by a double-sided weld to a wraparound bar located in the periphery of the tube bundle. The center region of the tube bundle contains no tubes and is referred to as the stay-cavity region.

Routine eddy current testing of the steam generator tubes in 2005 identified two diagonal batwing supports in steam generator 2 that had moved. The two batwings were displaced from their nominal locations on the cold-leg side of tubes in columns 82, 83, and 84. These batwings were at their nominal locations during the previous inspection. Wear scars were observed for tubes in these columns during the 2005 inspections. These wear scars occurred in the free span of the tube at the nominal axial location of the batwing and thus were apparently formed before the displacement of the batwings. These wear indications were not observed during the previous inspection. The depth of these wear indications ranged from 7 to 30 percent of the tube wall thickness.

The batwing assembly is formed by two opposing diagonal bars connected by a short horizontal bar. A visual inspection of the lower portion of the batwings confirmed that two batwings had failed at the intersection of the horizontal bar and a slotted bar, which is perpendicular to the horizontal bar and is keyed to the horizontal bar. The slotted bar holds the lower portion of the batwing in place. The licensee concluded that fatigue was the failure mechanism, based on the location of the failure, the length of the batwing (one of the longest in the steam generator), and the flow in this region of the tube bundle. The loads on the batwing in this region are not high enough to cause an overload-type failure.

As a result of these findings, the licensee took several corrective actions, including plugging and stabilizing many tubes, performing analyses, and evaluating the integrity of the batwing-to-wrapper bar welds. The licensee conducted the analyses to confirm that, if additional batwings fail, tube integrity will not be compromised for the period of time between tube inspections. The evaluations were intended to ensure that the failed batwings would not become free to move throughout the steam generator (i.e., become loose parts). The batwing-to-wrapper bar welds connect all of the batwings and are located on the outside of the tube bundle to permit access for visual inspection [Ref. 10].

No related operating experience has been identified at similarly designed plants. The licensee has not removed any of the failed portions of the batwing from the steam generator because of the general inaccessibility of this portion of the tube bundle. Differing conclusions exist regarding the role of thinning of the batwings as a causal factor. The licensee chemically cleaned the Waterford steam generators in 2000 and 2003.

Subsequent outages have revealed additional batwing degradation. The discussion below summarizes the findings from the most recent outage, in 2008 [Ref. 11].

A visual inspection of steam generator 1 revealed no degradation of the wraparound bar or the welds between the wraparound bar and the batwings. The licensee repaired one single-sided weld between columns 85 and 86 on the hot-leg side in 2008. A visual inspection of the batwing-to-tube interface, at the innermost row of tubes adjacent to the stay-cavity region, identified tube wear, including through-wall wear. This wear was expected, based on operating experience at other plants in the 1980s.

The affected tubes were previously stabilized and plugged in response to this operating experience. In some cases, the stabilizing cable was visible. There was no wear evident on the stabilizing cable. Evaluations of all observed wear, including a few wear indications on the second row of tubes from the stay-cavity region, determined it to be acceptable and within expectations. The tubes in the second row of tubes from the stay-cavity region were also previously plugged but were not stabilized. Visual inspections revealed that six to eight batwings might be broken at the intersection of the batwing and the perforated center support plate located in the stay-cavity region; however, none of these batwings were detached from the center support plate.

A visual inspection of steam generator 2 in 2008 revealed no degradation of the wraparound bar. Regarding the welds between the wraparound bar and the batwings, and the weld-clips installed in 2006 to correct insufficient welds between the wraparound bar and the batwings, there was no significant degradation or change, except for the batwing on the cold-leg between columns 84 and 85, which had slipped into the tube bundle (as had been previously observed in 2006). A visual inspection of the batwing-to-tube interface, at the innermost row of tubes adjacent to the stay-cavity region, identified tube wear, including through-wall wear. This wear was expected, based on operating experience at other plants in the 1980s. The affected tubes were previously stabilized and plugged in response to this operating experience. In some cases, the stabilizing cable was visible. There was no wear evident on the stabilizing cable. Wear was also visually detected at the intrados of some tubes. There are no broken or deformed batwings in the immediate vicinity of these wear indications. Evaluations of all observed wear, including a few wear indications observed on the second row of tubes from the stay-cavity region, determined the wear to be acceptable and within expectations. The tubes in the second row of tubes from the stay-cavity region were also previously plugged but not stabilized. Four batwing segments (loose parts) were observed, including one that appears to have moved since the 2007 midcycle inspection. The loose part that appears to have moved is now lodged between several tubes in the upper stay-cavity region. The licensee concluded that this segment is fixed in its current position and is not expected to migrate further into the tube bundle. All tubes that are in contact with this loose batwing segment have been plugged (and some have been stabilized). Visual inspections revealed extensive batwing degradation in the stay-cavity region, including missing pieces of some batwings (which are the source of the four loose parts mentioned previously). There has been no significant change in the batwing condition since the midcycle outage. The batwing between columns 84 and 85, which slipped into the tube bundle since it was disconnected from the wraparound bar (this condition was identified in 2006), has not slipped into the central cavity. In 2008, the licensee hydraulically expanded several tubes around this batwing to lock it in place.

The licensee plans to replace the Waterford steam generators in 2011.

### 4.2 Tie-rod bowing at Arkansas Nuclear One, Unit 1

Arkansas Nuclear One (ANO), Unit 1, replaced their two once-through steam generators in 2005. The steam generators, designed and fabricated by the French company, AREVA NP, have straight tubes that extend from a lower tubesheet to the upper tubesheet and are supported by 15 stainless steel tube support plates.

The tube support plates are centered by wedges attached to the shroud. There is no gap between the wedge and the tube support plate during cold conditions. However, since the thermal expansion coefficient for the tube support plate is less than the thermal expansion coefficient for the shroud, there should be a slight gap between the tube support plate and the wedge under normal operating conditions. This gap permits the tube support plates to move freely in the axial direction.

There are 52 tie rods that support and connect the tube support plates. These 52 tie rods are located in four concentric circles and extend from the lower tubesheet to the 15$^{th}$ tube support plate (i.e., the tie rods do not extend from the 15$^{th}$ tube support plate to the upper tubesheet). The tie rods in the first span (i.e., between the lower tubesheet and the first support plate) are longer and smaller in diameter than the remaining tie rods. The reduced diameter tie rods were used in this span to improve the ability to lance any sludge that accumulates at the top of the tubesheet.

A shroud/wrapper separates the incoming feedwater and outgoing steam from the tube bundle. The shroud/wrapper is in two pieces, an upper shroud and lower shroud. The lower shroud extends past the ninth tube support plate, and the upper shroud starts slightly above the top of the lower shroud. Tube supports 1, 14, and 15 are unique in that they have filler plates between the edge of the tube support and the wrapper/shroud. These filler plates lower the bypass flow at the periphery of the tube bundle.

The first inservice inspection following installation of the steam generators (i.e., in 2007) at ANO-1 resulted in three significant inspection findings: (1) eddy current data indicated that tubes and tie rods were in close proximity in steam generator A, which indicates that the tie rods had bowed; (2) tube wear at the support plate elevations was greater than anticipated; and (3) the number of wear indications at the eighth tube support plate in steam generator A was larger than in steam generator B and had a distinct pattern [Ref. 12].

At the time of the 2007 outage, bowed tie rods were only observed in the first span (i.e., between the lower tubesheet and the first support plate) of steam generator A. The bowing was in the direction of the center of the tube bundle. Subsequent to the outage, the licensee concluded that tie-rod bowing occurred in the 14th and 15th span (i.e., between the 13th and 14th support plate and the 14th and 15th support plate, respectively) in steam generator A [Ref. 13].

In all, tie-rod bowing was detected in 9 of the 52 tie-rod locations. The bowing was limited to the two outermost tie-rod rings, on what is referred to as the "Z-side" of the steam generator. In the outermost ring of tie rods, bowing was observed in the 1st, 14th, and 15th spans. In the second outermost ring (the next ring of tie rods in), bowing only occurred in the first span.

The licensee assumed the tie-rod bowing resulted from the inability of the upper tube support plates to move freely in the steam generator as the plant temperature decreased, causing the tube support plates to become locked to the upper shroud on one side of the shroud and partially locked on the other side during the cooldown of the plant. This locking of the tube support plates then resulted in the application of a compressive load to the tie rods, which caused the bowing. The extent of the bowing is believed to be primarily elastic, resulting in an essentially nominal support configuration under normal operating conditions. The licensee observed no wear indications on tubes in close proximity to other tubes or tie rods.

In 2008, the second inservice inspection of the replacement steam generators once again revealed tie-rod bowing. As with the 2007 outage, the bowing only occurred in steam generator A, and there was no wear on the tubes as a result of this phenomenon (tubes in close proximity to tie rods or other tubes as a result of tie-rod bowing). Preliminary information from the outage regarding the location of wear scars relative to the tube support plate surfaces in the cold condition suggested that increased locking of the supports on the side of the steam generator without bowing has led to increased bowing on the other side. Although the amount of bowing appeared to grow slightly between 2007 and 2008, it was still within its expected range, as discussed below.

During the 2008 outage, the licensee again detected tie-rod bowing in the original nine tie-rod locations, plus one additional location at row 47. The bowing was limited to the Z-side of steam generator A, similar to the observations in 2007. In the outermost ring of tie rods, some of the tie-rod locations that had bowing in the 1st, 14th, and/or the 15th span in 2007 also exhibited bowing in the 2nd and 13th spans in 2008. Although the bowing in the 2nd and 13th spans appeared to be new, a review of the eddy current data from 2007 indicated incipient bowing at these locations.

In the second outermost ring of tie rods, evidence of new bowing was observed in the 14$^{th}$ and 15$^{th}$ spans at those tie-rod locations where bowing occurred in the 1$^{st}$ span in 2007. The bowing in the first span was still present in 2008.

The magnitude of the bowing observed in 2008 met the operability acceptance criteria established by the licensee; however, changes to previously developed models were made based on the results of the 2008 inspection. These revised models and analyses did not affect the conclusion regarding steam generator operability [Ref. 14].

### 4.3 Cracking in thermally treated Alloy 600 tubes

As discussed above, 17 units in the United States have steam generators with thermally treated Alloy 600 tubes. In general, this material is considered more corrosion resistant than the mill-annealed Alloy 600 tubing used in the steam generators put into service in the 1960s and 1970s. In addition to using a more corrosion-resistant material, the steam generators with thermally treated Alloy 600 tubing are expected to be less susceptible to degradation as a result of other design features. The use of a hydraulic technique to expand the tubes in the tubesheet is expected to result in less stress at the expansion transition and therefore limit the susceptibility of this location to stress-corrosion cracking when compared to tubes that were expanded with other methods (e.g., mechanical rolling). All of the units with thermally treated Alloy 600 tubes have tubes that were expanded into the tubesheet with a hydraulic expansion process. In addition, all have tube support plates that were constructed from stainless steel, which is expected to eliminate the potential for tube denting that can also lead to tube cracking.

The steam generators at these units have been in service for approximately 20 years, on average. In 2002, the first incidence of corrosion-related cracking was reported in units with thermally treated Alloy 600. This cracking was attributed to nonoptimal tube processing (refer to NRC Information Notice 2002-21, Supplement 1, "Axial Outside-Diameter Cracking Affecting Thermally Treated Alloy 600 Steam Generator Tubing," dated April 1, 2003 [Ref. 15]). Since then, a few other licensees with thermally treated Alloy 600 tube material have observed crack-like indications at several different locations in their steam generators.

Crack-like indications that initiate from the inside surface of the tube have been observed near the tube end and possibly extending into the tube-to-tubesheet weld, and within bulges inside the tubesheet region. (A bulge is created when the tube is expanded into a tubesheet bore hole that is not perfectly round.) The crack-like indications within the bulges have only been observed on the hot-leg side of the steam generators; however, the crack-like indications near the tube-end and possibly extending into the tube-to-tubesheet weld have been observed both on the hot-leg and cold-leg sides of the steam generators. NRC Information Notice 2005-09, "Indications in Thermally Treated Alloy 600 Steam Generator Tubes and Tube-to-Tubesheet Welds," dated April 7, 2005 [Ref. 16], summarizes the initial reported occurrence of crack-like indications in the tubesheet region. Additional reports of crack-like indications are summarized in NRC

Information Notice 2008-07, "Cracking Indications in Thermally Treated Alloy 600 Steam Generator Tubes," dated April 24, 2008 [Ref. 17].

Crack-like indications that initiate from the outside surface of the tube have been observed in the expansion transition region, in the portion of tube slightly above the expansion transition, and at the tube support plate elevations (in tubes with nonoptimal tube processing). All of the indications that initiated from the outside surface of the tube near the top of the tubesheet were on the hot-leg side of the steam generator. The crack-like indications at the tube support plate elevations were observed on both the hot- and cold-leg sides of the steam generator.

The number of tubes with corrosion-related cracking is small in comparison to the approximately 275,000 thermally treated Alloy 600 tubes in service. Although only a small number of tubes have been identified with crack-like indications, these findings indicate that the tubes are potentially susceptible to cracking at a variety of locations.

The majority of the crack-like indications are in the portion of the tube confined within the tubesheet. Of the crack-like indications in the tubesheet region, most are near the tube-end welds and are a mixture of axial and circumferentially oriented cracking. Given that cracks in the portion of the tube within the tubesheet cannot burst and are generally regarded as nonsafety significant, the U.S. nuclear industry has proposed to limit the extent of inspection in the tubesheet region to the uppermost portion of the tubesheet. This proposal, referred to as H* (H-star), would permit tubes with flaws that may occur beneath the inspected region of the tube to remain in service. The H* distance is that distance below the top of the tubesheet over which sufficient frictional force, with acceptable safety margins, can be developed between each tube and the tubesheet under tube-end cap pressure loads associated with normal operating and design-basis-accident conditions. This prevents significant slippage or pullout of the tube from the tubesheet, assuming the tube is fully severed at the H* distance below the top of the tubesheet. The H* distance varies among the steam generator models. The NRC staff is currently reviewing this proposal and has allowed implementation of this approach for a limited time, pending final review.

### 4.4 Widespread wear in replacement once-through steam generators

As discussed above, seven units in the United States have once-through steam generators. Licensees of four units have replaced their steam generators and two plan to replace them in the fall of 2009. Licensees of all four units that have replaced their steam generators have observed a significant number of wear indications at the tube support plate elevations. Although the indications detected have been minor, they have resulted in more frequent inspections at these units when compared to other units with replacement steam generators with Alloy 690 tubes. The number of wear indications has resulted in some design changes in at least one of the units scheduled for a steam generator replacement in the fall of 2009. The information from this unit will be useful in assessing any corrective actions at the other units.

### 4.5 Buildup of deposits in steam generators

Corrosion products accumulate in the secondary side of the steam generator as a result of the gradual erosion and corrosion of secondary-side components. This accumulation of corrosion products results in the buildup of deposits on the tubes, tubesheets, and other secondary-side steam generator structures (including the holes through which the tubes pass).

Harmful contaminants can concentrate in these deposits and result in corrosion of the steam generator tubes. In addition, these deposits can affect the thermal performance of the steam generator (i.e., the ability to transfer heat from the primary-to-secondary side of the steam generator) and the thermal-hydraulic characteristics of the steam generator (by changing the flow patterns within the steam generator). For example, extensive deposit buildup in the tube support holes can change the flow characteristics enough to result in increased vibration of the tubes. This increased vibration could lead to fatigue cracking of the tube. Deposits can also change the loading (stresses) on the tube supports during transients and design-basis accidents (e.g., a steamline break). Extensive deposit buildup in the tube support holes can change the secondary water recirculation rate and may result in water level oscillations within the steam generator.

The extent of deposit buildup in the steam generator (including the tube support holes) varies from unit to unit. It is a function not only of the tube support configuration (e.g., lattice-grid, round hole, quatrefoil-shaped holes) but also of the design and operation of the secondary side of the plant. Low secondary-side pH levels may increase the corrosion rate on the secondary side of the plant and lead to the transport of more impurities to the steam generators. Chemical intrusions (e.g., from main condenser leakage) may also increase the transport of impurities into the steam generator. The more impurities that enter the steam generator, the more likely that deposits will build up on the secondary side of the steam generator.

Some relatively recent operating experience shows deposit buildup changing the flow characteristics on the secondary side of the steam generators. At one facility, high cycle fatigue cracks developed as a result of flow-induced vibration. The tubes became susceptible to vibration and fatigue as a result of the buildup of deposits on the secondary side of the steam generator, which changed the flow conditions in the center of the tube bundle. The deposits had blocked water or steam flow through the quatrefoil-shaped holes in the tube support plates, forcing more water or steam into the center of the tube bundle. Estimates of the extent of the hole blockage were based on visual examinations, an analysis of eddy current test results, and an evaluation of the wide-range feedwater level gauge readings. Inspections and analyses revealed high levels of deposits.

To address this problem, several corrective actions were considered, including evaluating the level of hole blockage on tube support plates, removing the deposits through chemical cleaning, changing the chemistry conditions on the secondary side of the plant to reduce the rate of buildup of deposits, analyzing the consequences of the deposits on the flow through the steam generator, and analyzing the stresses that could be imposed on the tube support plate during transients and accidents as a result of the hole blockage.

Although there is no specific requirement for licensees to monitor, assess, or remove deposit buildup, they are required, in part by plant technical specifications, to maintain steam generator tube integrity. Therefore, it is important to assess the deposit buildup and the effects that deposits will have on steam generator performance and tube integrity during normal operation and design-basis accidents. Promptly identifying and removing significant deposit buildup may prevent a loss of tube integrity and may improve the thermal performance of the steam generator.

As a result of the negative effects of these deposits, plant operators in the United States frequently monitor the deposit loading in their steam generators. In addition, they frequently remove the deposits from the top of the tubesheet by a process referred to as sludge lancing. Operators also occasionally remove these deposits from other areas in the steam generator through other processes, such as chemical cleaning.

The NRC continues to monitor operating experience related to deposit buildup to ensure these deposits do not have an adverse effect on tube integrity or plant safety [Ref. 18].

## 5. CONCLUSION

The NRC has a risk-informed, performance-based approach for regulating steam generators. This approach provides flexibility to plant operators while ensuring plant safety. As with any performance-based approach, monitoring the performance of the program and taking appropriate corrective action, when needed, is critical to its success. The NRC continues to follow implementation of this performance-based approach to ensure that its licensees maintain tube integrity and operate the plants safely.

The nuclear industry has seen better steam generator performance over the last several decades, as a result of improved inspection and monitoring programs, as well as the replacement of steam generators with more degradation-resistant designs. Nonetheless, steam generator issues continue to require attention. Current operating issues include degradation of supports, cracking in thermally treated Alloy 600 tubing, extensive wear in replacement once-through steam generators, and the effect of the buildup of deposits on steam generator performance. Given the importance of steam generator tube integrity on safe plant operation, it is important to promptly address safety-significant steam generator issues.

## 6. REFERENCES


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