February 13, 2019 SGTF Presentation - "*Operational Assessment Process Could Safely Replace Existing Prescriptive Technical Specification Inspection Intervals*"

Rick Maurer's Comments:

Although I am generally supportive of using the results of the operational assessment to define acceptable inspection periodicity as the industry has proposed, I am somewhat concerned about moving from prescriptive requirements to variable performance-based requirements given that complex OAs can produce quite different results depending on assumptions made on key input parameters. For example, if the probability of detection, beginning of cycle population of undetected flaws, measurement uncertainties, growth rates, etc., are misinterpreted or in error, then even fully probabilistic modeling can yield misleading results. In addition, the EPRI Steam Generator Integrity Assessment Guidelines allow multiple approaches in performing an operational assessment. A complex OA which provides high confidence that performance requirements will be satisfied at the end of the inspection interval requires highly experienced and knowledgeable tube integrity engineers. In my opinion, simply following the EPRI Tube Integrity Assessment Guidelines does not necessarily provide such assurance given the latitude in the document to follow a number of alternative approaches.

The EPRI slides used during the SGTF meeting provide example plants to illustrate their position with Plant A representing an alloy 690TT design and Plant B an alloy 600TT design. I will comment on each design type separately and conclude with my opinion.

Second generation steam generators with thermally treated alloy 600 tubing:

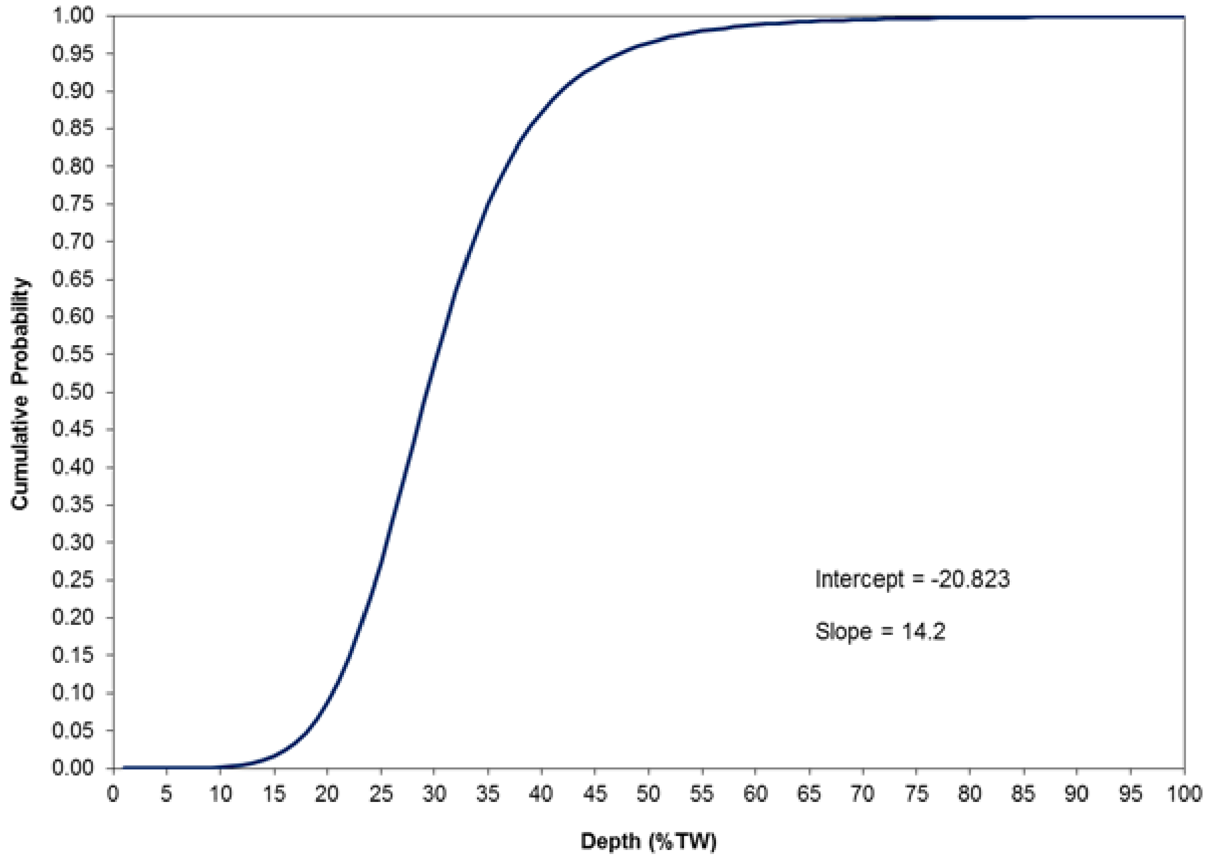
There are several examples from the industry presentation that illustrate potential weaknesses in the assumptions used in the operational assessment process:

- The third bullet on slide 27 states: *"Expect that only a limited number of crack indications with minor severity will be occasionally observed in the future"*. The term "minor severity" is an appropriate generalization for the majority of the cracks but there are some notable exceptions.
  - Vogtle Unit 1 (in 2008) SG 4 Row 11 Column 62, axial ODSCC at the top of the hot leg tubesheet. This tube was removed for metallographic analysis and the maximum crack depth on all three cracks was 100% through-wall.
  - Vogtle Unit 1 (in 2008) SG 4 Row 12 Column 98, circumferential ODSCC at the top of the hot leg tubesheet. This tube was also removed for metallographic analysis and the maximum crack depth was 80% through-wall.
  - Vogtle Unit 1 (in 2009) SG 3 Row 1 Column 20, axial PWSCC in the u-bend area required ISPT, 100% through-wall (leaked during the test).
  - Braidwood Unit 2 (in 2012) SG C Row 44 Column 47, axial ODSCC at HL TSP #3, required ISPT. [redacted].
  - Had these units skipped the inspections during which these flaws were detected the cracks would presumably have continued to grow and could have potentially challenged tube integrity over the period of the subsequent operating interval.

- The first bullet on slide 28 states: *"Industry trends and plant OE show that cracking indications reflect flaws in small tube sub-populations"*.
  - This was an accurate characterization at one point in time after axial ODSCC at tube support locations was detected at Seabrook in 2002. This was initially limited to high stress tubes from the manufacturing process. However, subsequent experience in 2012 showed that this degradation mechanism is not limited to high stress tubes. Low row tubes with stress relieved u-bends displaying the "[redacted]" in the low frequency eddy current strip chart data have been identified and preventively plugged at most plants. Higher row tubes do not display unique eddy current characteristics and those that potentially have high stress were identified by applying a statistical threshold (minus two sigma) to the eddy current voltages measured at the u-bend tangent regions. Industry wide the -2 σ tubes are mostly still in service. Some plants perform additional +Point or X-Probe testing at tube support locations of all in-service tubes identified as potential high stress which allows an improved POD to be applied in the operational assessment.
  - Field experience at Braidwood Unit 2 in [redacted] and in 2012 showed cracks in two tubes that were high stress tubes but they had not been identified as such during the 2003 eddy current review for this purpose. Of course, if they are not all identified, then they are examined using only the bobbin probe and crack growth over two cycles of operation becomes a potential concern.
  - Early detection of incipient cracking is important given the uncertainties associated with growth rate. [redacted].
  - The circumferential and axial ODSCC at Vogtle Unit 1 is not correlated with high stress tubes and is also not limited to a small sub population of tubes.
  - Circumferential PWSCC within the tube sheet was initially believed to be associated only with bulges and over expansions from the manufacturing process. Eddy current reporting of such geometry variations are based on amplitude ($\geq$18 volts) or estimated diametral expansion values ($\geq$0.0015"). Recent results in the last several years show this flaw mechanism at locations with geometry variations below these reporting thresholds.

- Another potential weakness is in the assumptions used to estimate the beginning of cycle population of undetected flaws: Slide 31 of the industry presentation discusses a plant that detected axial PWSCC with an array probe at the top of the tube sheet. Slide 33 which depicts the probability of detection shows an approximate 80% to 85% probability of detection at crack depths of 35% to 40% depth.
  - [redacted].
  - The example Plant B OA POD would appear to be an overestimate of the technique's actual demonstrated performance. This may be an artifact of the curve used to fit the dataset results or may simply be an error. In either case if this POD is used to estimate the beginning of cycle population of undetected flaws then it will likely be underestimated. Subsequent Monte Carlo simulations may then be inaccurate in estimating the probability of burst or probability of leakage.

Plant B Operational Assessment Example for Axial PWSCC



[redacted]

- Another factor to consider in whether skipped inspections are appropriate for alloy 600TT plants that have experienced axial ODSCC is how benign signals are addressed during the inspection.
  - Benign signals refer to bobbin coil indications that resemble flaws but originate from benign conditions such as manufacturing burnish marks or small dings introduced during the manufacturing process. Typically, there are many hundreds or thousands of these signals in A600TT plants. Tubes with free span axial ODSCC detected in 2012 at Seabrook and Braidwood Unit 2 were associated with benign signals. These signals are typically evaluated by comparison with historical eddy current data from the first in-service inspection or first inspection with data recorded on digital storage media. If the signals vary by more than the analysis guideline criteria ([redacted]) the indication is tested with a +Point probe or an X-probe to determine whether ODSCC is present. The signal change criteria are a best estimate of what the expected variance is for normal eddy current signal repeatability; it is not based on test data from benign signals that are influenced by the presence of stress corrosion cracking. [redacted]. The flaw signals are all from pulled tubes with known depths and the eddy current analysts did not have access to the ground truth results. The POD that is derived from this exercise represent system performance which is the result of the combined technique as well as analyst error and they are referred to as Appendix I techniques. <u>None</u> of the flaws contained in the analysis round robin exercise are reported based on signal change from historical data. [redacted].
  - NUREG-1771 US Operating Experience with Thermally Treated Alloy 600 Steam Generator Tubing (2003) states the following with regard to these types of signals:
  - *"The few tubes pulled for destructive examination suggest that manufacturing anomalies or some other phenomena are producing signals indicative of degradation. The ability of nondestructive examination techniques to distinguish true flaw signals from these anomalous inspection signals may become important as the second-generation steam generators age (and the potential for corrosion increases)*.
  - [redacted].

- Yet another factor to consider in whether skipped inspections are appropriate for alloy 600TT plants that have experienced axial ODSCC is the eddy current sizing uncertainty and how this impacts the estimates for the beginning of cycle population of undetected flaws and the growth distribution used in Monte Carlo simulations. The most reliable eddy current technique to estimate axial ODSCC depth is the +Point probe. [redacted]. For example, a crack with an eddy current measured depth of 45% through-wall is equally likely to have a true depth of 25-30%, as it is 45%, or 65-70%. [redacted]. In condition monitoring the NDE depth estimate is corrected by the sizing regression equation. [redacted]

[redacted] While the affected tubes are not being returned to service, this would appear to be an irrelevant factor with regard to estimating a BOC population. If the number and depth distribution of the undetected population of cracks is underestimated then subsequent Monte Carlo simulations applying a distribution of growth rates to this population will likely underestimate the end of cycle leak and burst probabilities. This is but one example of my general concern associated with using the OA to determine inspection periodicity. That is, I believe that there is sufficient latitude within the TIA Guidelines to arrive at an inaccurate probability of leak/probability of burst assessment unless the tube integrity engineer is highly experienced. Given the potential for error, I believe that NRC review of the OA should be requirement for any plants seeking to skip inspections that would otherwise be required under the current plant technical specifications.

[redacted]

Third generation steam generators with thermally treated alloy 690 tubing:

- I am skeptical about the ability to accurately predict tube wear initiation and growth rates over extended intervals beyond the current prescriptive requirements. Accurate predictions rely on the premise that thermal-hydraulic conditions on the secondary side of the steam generator do not vary significantly. Specifically, I am concerned about the cumulative build-up of deposits on the outside surface of the tubing and how these can influence wear patterns and growth rates. For example, in the original San Onofre Unit 3 steam generators

(Combustion-Engineering) tube wear at the diagonal and vertical support straps in the upper bundle was the predominant degradation mode from startup in 1984. However, by the mid-1990s fouling and erosion/corrosion of the lower support eggcrates had caused significant wear in some tubes at these elevations. Insitu pressure testing was subsequently required to establish that tube integrity had been maintained over the previous operating interval.

- I would also question one allowable methodology used to determine wear propagation rates. [redacted] With some plants growing new $\geq$40% wear indications over the inspection interval, exclusion of these datapoints would appear to be non-conservative. [redacted].

- Another consideration with regard to extending the inspection interval from a maximum of every third refueling outage to an unlimited interval based on the operational assessment is the impact this has on the administrative limit used to determine which tubes must be removed from service. There are a number of plants that are plugging tubes at a wear depth of approximately 25% through-wall rather than the 40% limit specified in plant technical specifications. This is done to ensure that existing degradation does not continue to propagate and potentially exceed tube integrity margins given that the tube will not be re-inspected for several cycles. Of course, from a nuclear safety perspective, the primary purpose of a SG tube is to cool the reactor during postulated accident conditions. Although steam generators are designed with more tubes than necessary to provide core cooling under accident conditions, removing tubes from service with wear depths well below the repair limit reduces the plugging margin. Skipping more than two inspections would likely result in even further reductions in the administrative repair limit.

- Opinion – 600TT Plants:
  - Given the uncertainties associated with axial and circumferential ODSCC sizing and growth rates, I do not believe that skipping the next refueling outage inspection following initial detection is advisable. Without a next refueling outage inspection one cannot be confident whether the cracking is limited to a single or small number of tubes as in the case of Braidwood Unit 2 or conversely will become more widely distributed and periodic as in the case of Vogtle Unit 1.
  - For those plants that have experienced ODSCC and in the following inspection detected none or for those plants in which ODSCC is a potential degradation mechanism but have detected none and wish to skip more than one inspection, I believe there is a reasonable path forward. If the industry wishes to pursue additional time between inspections then cracks must be detected at a shallower state than they currently are with the bobbin coil alone. With the existing plant technical specification limitation that prohibits skipping the next refueling outage inspection following detection of a crack, plants are not necessarily incentivized to use the most sensitive examination methods. I would respectfully suggest that our mutual interests (public, regulator, industry) are best served by implementing improved detection methods in exchange for relaxed inspection intervals provided that the operational assessment supports it. Detection of incipient cracking with advanced probe types provides a higher confidence that cracks will not grow to exceed tube integrity requirements over two cycles of operation. A reasonable approach for the A600TT plants is to position themselves for a potential skip inspection by implementing a 100% full length array probe inspection each time the steam generators are examined. The benefits would include:

- The hot leg tubesheet area would have a 100% inspection with a qualified examination technique versus the statistically based sampling currently conducted.
- The cold leg top of tubesheet area would have a 100% inspection of the expansion transition area with a qualified examination technique. Most plants currently do not conduct sludge pile area testing other than with the bobbin probe. In the original Millstone Point Unit 2 SGs (mill annealed A600 tubing) approximately 40% of the tubes with circumferential ODSCC were located in the cold leg.
- 100% of the benign signals would receive examination with a qualified examination technique versus only those which exhibit change by the bobbin coil.
- 100% of the broached tube supports would be examined with a qualified examination technique which industry experience has shown to be more sensitive than the bobbin probe.
- 100% of the free span dings < 5 volts would be examined with a technique qualified for detection of circumferential ODSCC. Although all 600TT plants consider axial ODSCC to be a potential degradation mechanism at these locations, I know of none that consider circumferential ODSCC as a potential mechanism. There were a small number of reported instances of these cracks in the mill annealed A600 plants.
- 100% of the hot leg and cold leg top of tubesheet would be examined with a technique sensitive to foreign object wear. The bobbin coil's detection capability is limited in this region by the masking effects of the expansion transition.
- 100% of the hot leg and cold leg top of tubesheet would be examined with a technique sensitive to loose part detection. The bobbin coil's detection capability is limited in this area by the masking effects of the carbon steel tubesheet on the low frequency channel.
- Such an inspection program would allow earlier detection of incipient cracking by using a more sensitive technique and testing 100% of the susceptible regions each inspection rather than only a sample as is currently required.

- For PWSCC that resides below the top of the tubesheet but above the H* distance, I believe that initiation and growth rates are less uncertain than those for ODSCC. With the tube restrained from burst and with potential leakage limited there is a much lower risk associated with skipping the next inspection than there is for ODSCC.

- Opinion 690TT Plants:
    - For those plants with tube support or AVB wear that would like to skip more than two inspections, I think that it is acceptable to use the operational assessment to determine the inspection periodicity provided that the assessment is submitted to the NRC for review. Although I am skeptical about the ability to accurately predict tube wear beyond the current prescriptive inspection periods, there are some plants where the risk would appear to be low. For instance, the RSGs at Point Beach Unit 2 are a standard broached tube support and AVB design, with 20 plus years since installation, and only a handful of wear scars all less than 10% TW. Other RSGs with non-standard support designs, less time since replacement, and/or recent inspections with significant wear detected pose a higher degree of risk. For any extension of the current prescriptive inspection periods I would recommend that the potential for changes in secondary side thermal hydraulic conditions be considered in the operational assessment.