TVA

Tennessee Valley Authority
Post Office Box 2000
Soddy Daisy, Tennessee 37384-2000

Timothy P. Cleary
Site Vice President
Sequoyah Nuclear Plant

May 21, 2009

TVA-SQN-TS-09-02 10 CFR 50.90

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555-0001

In the Matter of) Docket No. 50-328
Tennessee Valley Authority (TVA))

SEQUOYAH NUCLEAR PLANT (SQN) - UNIT 2 - TECHNICAL SPECIFICATIONS (TS) CHANGE 09-02 – W* ALTERNATE REPAIR CRITERIA (ARC) FOR STEAM GENERATOR (SG) TUBES COLD LEG

Pursuant to 10 CFR 50.90, Tennessee Valley Authority (TVA) is submitting a request for a TS change (TS-09-02) to License DPR-79 for SQN. The proposed TS change revises TS 6.8.4.k, "Steam Generator (SG) Program," for Unit 2 including associated Bases 3/4.4.5, "Steam Generator (SG) Tube Integrity," to allow the implementation of SG tubing ARC for axial indications in the Westinghouse Electric Company explosive tube expansion (WEXTEX) region below the top of the tubesheet and specify the W* distance for the SG cold legs.

The proposed amendment is consistent with Westinghouse WCAP-14797, Revision 2 "Generic W* Tube Plugging Criteria for 51 Series Steam Generator Tubesheet Region WEXTEX Expansions," and LTR-CDME-04-147, Revision 1, "Application of W* Alternate Repair Criteria to Sequoyah Unit 2 (Proprietary)." The proposed change is similar to the change approved by NRC letter to Diablo Canyon dated February 19, 1999, "Issuance of Amendments for Diablo Canyon Nuclear Power Plant, Unit No. 1 (TAC No. M98283) and Unit No. 2 (TAC No. M98284)," and NRC letter to Diablo Canyon dated October 28, 2005, "Diablo Canyon Nuclear Power Plant, Unit Nos. 1 And 2 - Issuance of Amendments Re: Approval of Permanent Use of W* Alternate Repair Criteria For Steam Generator Tubes (TAC Nos. MC6409 and MC6410)."

D030
NRR

The proposed amendment and schedule for approval were discussed with Brendan Moroney, Senior Project Manager, Tracy Orf, Project Manager, NRC technical staff, TVA, and Westinghouse personnel during a telephone conference held on February 10, 2009. The proposed amendment and schedule are consistent with those discussed during the conference. The proposed amendment will remain effective until the Unit 2 SGs are replaced. The SGs are scheduled for replacement during the October 2012 refueling outage.

TVA has determined that there are no significant hazards considerations associated with the proposed change and that the TS change qualifies for categorical exclusion from environmental review pursuant to the provisions of 10 CFR 51.22(c)(9). Additionally, in accordance with 10 CFR 50.91(b)(1), TVA is sending a copy of this letter and enclosures to the Tennessee State Department of Public Health.

TVA requests approval of this TS change by October 20, 2009, to support the next Unit 2 refueling outage scheduled to start in October 2009 and the implementation of the revised TS is requested to be within 60 days of NRC approval.

There are no regulatory commitments associated with this submittal. If you have any questions about this change, please contact Beth A. Wetzel at (423) 843-7170 or Rusty Proffitt at (423) 843-6651.

I declare under penalty of perjury that the foregoing is true and correct. Executed on this 21st day of May, 2009.

Sincerely,

Timothy P. Cleary

Timothy P. Cleary

Enclosure:
Evaluation of the Proposed Change

cc: See page 3

Enclosure
cc (Enclosure):

Mr. Siva P. Lingam, Project Manager
U.S. Nuclear Regulatory Commission
Mail Stop 08G-9a
One White Flint North
11555 Rockville Pike
Rockville, Maryland 20852-2739

Mr. Lawrence E. Nanney, Director
Division of Radiological Health
Third Floor
L&C Annex
401 Church Street
Nashville, Tennessee 37243-1532

ENCLOSURE

EVALUATION OF THE PROPOSED CHANGE

The proposed technical specification (TS) change revises TS 6.8.4.k, "Steam Generator (SG) Program," for Unit 2 including associated Bases 3/4.4.5, "Steam Generator (SG) Tube Integrity," to allow the implementation of SG tubing alternate repair criteria (ARC) for SG cold legs.

1.0 SUMMARY DESCRIPTION

This evaluation supports a request to amend Operating License DPR-79 for SQN Unit 2.

The proposed changes would revise the Operating License to allow the implementation of SG tubing ARC for axial indications in the SG cold legs that are 10.5 inches below the top of the tubesheet. This proposed amendment applies to Sequoyah Unit 2 TS 6.8.4.k including associated Bases 3/4.4.5 and is consistent with Revision 2 of Westinghouse Electric Company WCAP-14797 "Generic W* Tube Plugging Criteria for 51 Series Steam Generator Tubesheet Region WEXTEX Expansions," and LTR-CDME-04-147, Revision 1, Application of W* "Alternate Repair Criteria to Sequoyah Unit 2 (Proprietary)."

2.0 DETAILED DESCRIPTION

The following changes are proposed to Sequoyah Unit 2 TSs:

1. Clarify TS 6.8.4.k.c.2. b as it applies the W* distance to the hot leg tubesheet.

2. Add TS 6.8.4.k.c.2. c to define that the W* distance for the cold leg tubesheet is 10.5 inches below the top of the tubesheet.

3. Revise TS 6.8.4.k.d.5 to include a 20 percent sample inspection of the inservice cold leg tubes using an inspection probe qualified for detection of the expected degradation modes of the cold leg tubes commensurate with the specified cold leg W* distance.

4. Revise Bases 3/4.4.5 Safety Analysis item b) to include application of the W* ARC to both the hot and cold leg tubes. Item c) and item d) are being revised to apply the applicable W* leakage allowances to both hot and cold legs. Item d) will also be revised to include the provision that should no primary water stress corrosion cracking (PWSCC) indications be identified in the cold leg tubesheet region during the inspection the leakage allowance for the operational assessment will be considered zero gallons per minute.

During the SQN Unit 2, 2008 SG inspection, axial PWSCC indications were reported near the cold leg tube end on Row 1 Column 59 in SG No. 4. This tube was inspected using a Plus Point (+Pt) coil due to bobbin coil reported bulge (BLG) signals higher in the tubesheet. The +Pt examination of the bulges reported no degradation. Only one other tube (Row 9 Column 53 in SG No. 4) with BLG signals in the cold leg tubesheet was subsequently inspected using the +Pt coil. Degradation was not reported at the BLG location or at the tube end region for Row 9 Column 53 in SG No. 4. Previously, all

Row 1 tubes in SQN Unit 2 were plugged using roll plugs because of a PWSCC concern at small radius U-bends. These plugs in theses tubes were later removed and tubes were returned to service following U-bend heat treatment. The elevations of the indications on Row 1 Column 59 cold leg loosely coincide with the roll plug roll expansion region. The potential exists that additional Row 1 cold leg tube ends may also contain PWSCC, thus, TVA is proposing the application of the W* ARC to the cold legs on SQN Unit 2 to avoid unnecessary radiation exposure to plant workers and to perform inspection of and to avoid unnecessary plugging of those Row 1 tubes, which may be found to contain PWSCC at the cold leg tack roll region.

The proposed change requires that any cold leg tube identified with service induced degradation above the tubesheet mid-plane elevation (10.5 inches below the cold leg top of tubesheet) must be repaired. This application is conservative compared to the analysis results of Reference 2, which develops a cold leg W* distance of 7.5 inches below the bottom of the Westinghouse explosive tube expansion (WEXTEX) transition. Since the proposed change includes repair of any service induced degradation within the W* distance, this proposal is a conservative limited scope application of the complete W* methodology as described in Reference 2.

Performing a rotating pancake coil (RPC) inspection of the cold leg tubes in the SQN Unit 2 SGs to a depth of 8.5 inches below the top of the cold leg tubesheet or 7.5 inches below the bottom of the WEXTEX transition is sufficient to assure the structural and leak rate integrity of the tube bundle in accordance with industry and regulatory requirements. For the End of Cycle (EOC)-16 inspection, TVA will apply a cold leg inspection depth of 10.5 inches below the top of tubesheet. An initial sample of 20 percent of the cold leg active tubes will be performed in each SG at EOC-16. Inspection scope expansion will follow the guidance in Steam Generator Management Program, Pressurized Water Reactor Steam Generator Examination Guidelines: Revision 7. Cold leg RPC inspection for the EOC-17 outage will be determined based on the EOC-16 results; if no degradation is reported at EOC-16, RPC inspection of the cold legs will not be performed at EOC-17, consistent with the guidance in the Steam Generator Management Program. If no cold leg PWSCC is detected at EOC-16, the Cycle 17 operational assessment will not include a leakage allowance for the cold leg.

3.0 TECHNICAL EVALUATION

The SG tubes in pressurized water reactors have a number of important safety functions as described in the Sequoyah Updated Final Safety Analysis Report (UFSAR), Section 5.5.2. These tubes are an integral part of the reactor coolant pressure boundary and are relied upon to maintain the primary system's pressure and inventory (i.e., structural and leakage integrity). As part of the reactor coolant pressure boundary, the SG tubes are unique in that they are the safety-related heat transfer surface between the primary and secondary systems such that residual heat can be removed from the primary system. The SG tubes are also relied upon to isolate the radioactive fission products in the primary coolant from the secondary system. The general design criteria (GDC) requirements of the reactor coolant pressure boundary are identified in Title 10 of the Code of Federal Regulations Part 50 (10 CFR 50), Appendix A. Specific requirements governing the maintenance and inspection of SG tube integrity are contained in the Sequoyah Unit 2 TSs. These include requirements for periodic inservice inspection of the tubing and flaw acceptance criteria (i.e., plugging limit). These requirements, coupled with the broad scope of plant operational and maintenance programs, form the basis for ensuring adequate SG tube structural and leakage integrity.

The proposed change requires that any cold leg tube identified with service induced degradation above the tubesheet mid-plane elevation (10.5 inches below the cold leg top of tubesheet) must be repaired. This application is conservative compared to the analysis results of Reference 2, which develops a cold leg W* distance of 7.5 inches below the bottom of the WEXTEX transition. Since the proposed amendment will require repair of any service induced degradation within the W* distance, this proposal is a conservative limited scope application of the complete W* methodology as described in Reference 2.

As a consequence of implementation, any degradation occurring below the W* distance may remain in service regardless of its axial or circumferential extent. The amendment will be based on portions of WCAP-14797-P, Revision 2, entitled, "Generic W* Tube Plugging Criteria for 51 Series Steam Generator Tubesheet Region WEXTEX Expansions," Reference 2, and the following information developed herein. The W* analysis accounts for the reinforcing effect that the tubesheet has on the external surface of the SG tubes within the tubesheet region.

This proposed amendment addresses Generic Letter (GL) 2004-01 (Reference 4) with respect to defined tube inspection depth below the top of tubesheet using supplemental inspection techniques qualified for flaw detection in expanded tubesheet conditions, such as RPC or array probes. This proposed amendment also prevents the unnecessary plugging of potential indications at the cold leg tube end region, which have no structural or leakage consequence. Thus, plugging of such indications would not support as low as reasonably achievable (ALARA) fundamentals.

The technical bases is consistent with the technical bases supporting application of W* to the hot leg tubes (Reference 1), which inherently applies to the cold leg. Additional information included in Attachment 3 includes updating of the hot leg indication summary since 2005, estimates of the potential number of cold leg PWSCC indications, and discussion related to issues resultant from NRC review of another tubesheet region ARC developed for hydraulically expanded tubing. Discussions of issues raised during NRC review of other tubesheet region ARC are also included in Attachment 3.

Existing plant TS tube repair/plugging criteria apply throughout the tube length and do not take into account the reinforcing effect of the tubesheet on the external surface of an expanded tube. The presence of the tubesheet constrains the tube and complements tube integrity in that region by essentially precluding tube deformation beyond the expanded outside diameter (OD). The resistance to both tube rupture and tube collapse is significantly enhanced by the tubesheet. In addition, the proximity of the tubesheet in the expanded region significantly reduces the leakage of through-wall tube cracks. Based on these considerations, the establishment of ARC for the portion of tubing expanded by WEXTEX is supported by testing and analysis results included in Reference 2.

For Westinghouse Model 51 Series SGs with WEXTEX's at SQN Unit 2, the full depth tube to tubesheet expansion can be defined as follows. From the lower tube end and extending upward for a length of approximately 2.75 inches is a region expanded by a tube mechanical roll expansion process. From the top of the rolled expansion region to the vicinity of the top of the tubesheet, the expansion joint was produced by the

WEXTEX process. The resulting full depth tube to tubesheet expansion can be considered as four distinct areas. These are described in Reference 2 as:

1. The Roll Region – The region of tube that has been expanded by the tube rolling process. This region extends from the bottom of the tube to approximately 2.75 inches above the bottom of the tube.
2. The Roll Transition – The portion of the tube that extends from the roll expanded region of the tube to the initially unexpanded region, and is subsequently expanded by the WEXTEX process.
3. The WEXTEX Region – The portion of the tube expanded by the explosive expansion process to be in contact with the tubesheet. This region starts at the roll transition and extends to the WEXTEX transition in the vicinity of the top of the tubesheet.
4. The WEXTEX Transition – The portion of the tube that acts as a juncture between the WEXTEX region and the unexpanded region of the tube. The region starts at the top of the explosively expanded region and extends for approximately 0.25 inch.

The alternate SG tube repair criteria W* was developed by Westinghouse to permit tubes with predominantly axially oriented PWSCC in the WEXTEX and hardroll regions to remain in service. The W* analysis determined the W* length as measured from the bottom of the tube explosive expansion transition that would permit flaws below that length to remain in service and based on the assurance that adequate strength is available to resist the axial pull out loads experienced within the tubesheet during all plant conditions.

The following definitions apply with regard to describing the W* criteria:

The bottom of the WEXTEX transition as defined in Reference 2, as approximately 0.25 inch from the top of the tubesheet.

W* length – The maximum length of tubing below the bottom of the WEXTEX transition, which must be demonstrated to be non-degraded and is defined in Reference 2, Section 4.0 as 7.5 inches below the bottom of the WEXTEX transition on the cold leg side.

W* distance – The distance from the top of the tubesheet to the bottom of the W* length including the distance from the top of the tubesheet to the bottom of the WEXTEX transition and measurement uncertainties.

The W* analysis provides the basis for tubes with any form of degradation below the W* length to remain in service. The presence of the surrounding tubesheet prevents tube rupture and provides resistance against axial pull out loads during normal and accident conditions as discussed in Reference 2. In addition, any primary-to-secondary leakage from tube degradation below the W* length is determined to be acceptably low.

As discussed in more detail in Attachment 3, the generic W* analysis contained in Reference 2 is applicable to the SQN Unit 2 SGs and defines the maximum cold leg W* length for pull out resistance as 7.5 inches below the bottom of the WEXTEX transition for Zone B tubes, and 5.5 inches below the bottom of the WEXTEX transition for Zone A tubes. The maximum non-destructive examination (NDE) uncertainty on the W* distance in Reference 2 is 0.12 inch. Therefore, the required TS inspection distance below the top of the tubesheet, or bottom of the WEXTEX transition, whichever is lower, is 7.62 inches. As a conservative measure, TVA is applying a cold leg W* RPC inspection distance of 10.5 inches below the cold leg top of tubesheet. Any observed degradation within the observed inspection distance will be plugged. Consistent with previous W* applications, if degradation in the vicinity of the applied inspection distance is observed, the additional elevation uncertainty associated with the crack tip measurement in accordance with Reference 2 will be applied to determine the continued operability of the subject indication.

The proposed change is similar to the change approved by NRC letter to Diablo Canyon dated February 19, 1999, "Issuance of Amendments for Diablo Canyon Nuclear Power Plant, Unit No. 1 (TAC No. M98283 and Unit No. 2 TAC No. M98284)" and NRC letter to Diablo Canyon dated October 28, 2005, "Diablo Canyon Nuclear Power Plant, Unit Nos. 1 and 2 - Issuance of Amendments Re: Approval of Permanent Use of W* Alternate Repair Criteria for Steam Generator Tubes (TAC Nos. MC 6409 and MC6410)."

4.0 REGULATORY EVALUATION

4.1 Applicable Regulatory Requirements/Criteria

The regulatory requirements associated with steam generator (SG) tube inspections include the following:

10 CFR 50 Appendix A Criterion 1 – Quality standards and records, structures, systems, and components important to safety shall be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed. Where generally recognized codes and standards are used, they shall be identified and evaluated to determine their applicability, adequacy, and sufficiency and shall be supplemented or modified as necessary to assure a quality product in keeping with the required safety function. A quality assurance program shall be established and implemented in order to provide adequate assurance that these structures, systems, and components will satisfactorily perform their safety functions. Appropriate records of the design, fabrication, erection, and testing of structures, systems, and components important to safety shall be maintained by or under the control of the nuclear power unit licensee throughout the life of the unit.

10 CFR 50 Appendix A Criterion 2 – Design bases for protection against phenomena. Structures, systems, and components important to safety shall be designed to withstand the effects of natural phenomena such as earthquakes, tornadoes, hurricanes, floods, tsunami, and seiches without loss of capability to perform their safety functions. The design bases for these structures, systems, and components shall reflect: (1) appropriate consideration of the most severe of the natural phenomena that have been historically reported for the site and *surrounding area, with sufficient margin for the limited accuracy, quantity, and period of time in which the historical data have been accumulated, (2) appropriate combinations of the effects of normal and accident conditions with the effects of the natural phenomena and (3) the importance of the safety functions to be performed.*

10 CFR 50 Appendix A Criterion 4 – Environmental and dynamic effects design bases. Structures, systems, and components important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss-of-coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. However, dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analyses reviewed and approved by the Commission demonstrate that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

10 CFR 50 Appendix A Criterion 14 – Reactor coolant pressure boundary. The reactor coolant pressure boundary shall be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and gross rupture.

10 CFR 50 Appendix A Criterion 15 – Reactor coolant system design. The reactor coolant system and associated auxiliary, control, and protection systems shall be designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences.

10 CFR 50 Appendix A Criterion 19 - Control room. A control room shall be provided from which actions can be taken to operate the nuclear power unit safely under normal conditions and to maintain it in a safe condition under accident conditions, including loss-of-coolant accidents. Adequate radiation protection shall be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident. Equipment at appropriate locations outside the control room shall be provided (1) with a design capability for prompt hot shutdown of the reactor, including necessary instrumentation and controls to maintain the unit in a safe condition during hot shutdown, and (2) with a potential capability for subsequent cold shutdown of the reactor through the use of suitable procedures.

10 CFR 50 Appendix A Criterion 30 – Quality of reactor coolant pressure boundary. Components which are part of the reactor coolant pressure boundary shall be designed, fabricated, erected, and tested to the highest quality standards practical. Means shall be provided for detecting and, to the extent practical, identifying the location of the source of reactor coolant leakage.

10 CFR 50 Appendix A Criterion 31 – Fracture prevention of reactor coolant pressure boundary. The reactor coolant pressure boundary shall be designed with sufficient margin to assure that when stressed under operating, maintenance, testing, and postulated accident conditions (1) the boundary behaves in a nonbrittle manner and (2) the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the boundary material under operating, maintenance, testing, and postulated accident conditions and the uncertainties in determining (1) material properties, (2) the effects of irradiation on material properties, (3) residual steady state and transient stresses, and (4) size of flaws.

10 CFR 50 Appendix A Criterion 32 – Inspection of reactor coolant pressure boundary. Components which are part of the reactor coolant pressure boundary shall be designed to permit (1) periodic inspection and testing of important areas and features to assess their structural and leak tight integrity, and (2) an appropriate material surveillance program for the reactor pressure vessel.

10 CFR 50, Appendix B - establishes quality assurance requirements for the design, construction and operation of safety-related components. The pertinent requirements of this appendix apply to all activities affecting the safety-related functions of these components; these include, in part, inspecting, testing, operating and maintaining Criteria IX, XI, and XVI of Appendix B as applied to the SG tube integrity program.

10 CFR 100, Reactor Site Criteria - established reactor-siting criteria, with respect to the risk of public exposure to the release of radioactive fission products. Accidents involving leakage or burst of SG tubing may compromise a challenge to containment and therefore involve an increased risk of radioactive release. SQN Unit 2 is licensed for the use of an alternate source term in accordance with 10 CFR 50.67 for some design basis accidents.

Regulatory Guide 1.83, Revision 1 – "Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes"

Regulatory Guide 1.121, Revision 0 – "Bases for Plugging Degraded Pressurized Water Reactor (PWR) Steam Generator Tubes"

In accordance with 10 CFR 50.65, Maintenance Rule, SGs are classified as risk significant components because they are relied upon to remain functional during and after design basis events. SGs are to be monitored under 10 CFR 50.65 (a)(2) against industry established performance criteria. Meeting the performance criteria of NEI 97-06, Revision 1, provides reasonable assurance that the SG tubing remains capable of fulfilling its specific safety function of maintaining the reactor coolant pressure boundary.

There have been no changes to the plant design such that any of the regulatory requirements would come into question. This proposed amendment revises SQN Unit 2 TS Bases 3/4.4.5 to clearly delineate the scope of the SG inspection required in the tubesheet region. SQN will continue to comply with applicable regulatory requirements.

Based on the considerations discussed above, (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

4.2 Precedent

The proposed change is similar to the change approved by NRC letter to Diablo Canyon dated February 19, 1999, "Issuance of Amendments for Diablo Canyon Nuclear Power Plant, Unit No. 1 (TAC No. M98283) and Unit No. 2 (TAC No. M98284)" and NRC letter to Diablo Canyon dated October 28, 2005, "Diablo Canyon Nuclear Power Plant, Unit Nos. 1 and 2 - Issuance of Amendments Re: Approval of Permanent Use of W* Alternate Repair Criteria for Steam Generator Tubes (TAC Nos. MC6409 and MC6410)."

4.3 Significant Hazards Consideration

TVA has evaluated whether or not a significant hazards consideration is involved with the proposed amendments by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of Amendment," as discussed below:

1. Does the proposed amendment involve a significant increase in the probability or consequences of an accident previously evaluated?

   Response: No.

   Of the various accidents previously evaluated, the proposed changes only affect the steam generator tube rupture (SGTR) event evaluation and the postulated steam line break (SLB) accident evaluation. Loss-of-coolant accident (LOCA) conditions cause a compressive axial load to act on the tube. Therefore, since the LOCA tends to force the tube into the tubesheet rather than pull it out, it is not a factor in this amendment request. Another faulted load consideration is a safe shutdown earthquake (SSE); however, the seismic analysis of Westinghouse 51 Series steam generators (SGs) has shown that axial loading of the tubes is negligible during an SSE.

   TVA's amendment request allows taking credit for how the tubesheet enhances the tube integrity in the Westinghouse Electric Company explosive tube expansion (WEXTEX) region by precluding tube deformation beyond its initial expanded outside diameter. For the SGTR and SLB events, the required structural margins of the SG tubes will be maintained due to the presence of the tubesheet. Tube rupture is precluded for axial cracks in the WEXTEX region due to the constraint provided by the tubesheet. Therefore, the normal operating 3ΔP margin and the postulated accident 1.43ΔP margin against burst are maintained.

   The W* length supplies the necessary resistive force to preclude pullout loads under both normal operating and accident conditions. The contact pressure results from the WEXTEX process, thermal expansion mismatch between the tube and tubesheet and from the differential pressure between the primary and secondary side. Therefore, the proposed change results in no significant increase in the probability or the occurrence of an SGTR or SLB accident.

The proposed changes do not affect other systems, structures, components or operational features. Therefore, based on the above evaluation, the proposed changes do not involve a significant increase in the probability of an accident previously evaluated.

The consequences of an SGTR event are primarily affected by the primary-to-secondary flow rate and the time duration of the primary-to-secondary flow during the event. Primary-to-secondary flow rate through a postulated ruptured tube (i.e., complete severance of a single SG tube) is not affected by the proposed change since the flow rate is based on the inside diameter of a SG tube and the pressure differential. TVA's amendment request does not change either of these. The duration of primary-to-secondary leakage is based on the time required for an operator to determine that an SGTR has occurred, the time to identify and isolate the faulty SG, and ensure termination of radioactive release to the atmosphere from the faulty SG. TVA's amendment request does not affect the duration of the primary-to-secondary leakage because it does not change the control room indicators with which an operator would determine that an SGTR has occurred. The consequences of an SGTR are secondarily affected by primary-to-secondary leakage, which could occur due to axial cracks remaining in service in the WEXTEX region in a non-faulted SG. During a SGTR, the primary-to-secondary differential pressure is less than or equal to the normal operating differential pressure; therefore, the primary-to-secondary leakage due to axial cracks in the WEXTEX region of a non-faulted SG during a SGTR would be less than or equal to the primary-to-secondary leakage experienced during normal operation. Primary-to-secondary leakage is considered in the calculation determining the consequences of a SGTR and the value is bounding.

The postulated SLB has the greatest primary-to-secondary pressure differential, and therefore could experience the greatest primary-to-secondary leakage. TVA's amendment request allows axial cracks to remain in service in the WEXTEX region, which have the possibility of primary-to-secondary leakage during a postulated SLB accident. However, the primary-to-secondary leakage would be limited by the amount the crack face can open (compared to a similar free-span axial crack) and by the restriction resulting from the tube to tubesheet contact pressure which create a restricted leakage path from the upper tip of the crack to the top of the WEXTEX expansion. TVA's amendment request requires the aggregate leakage, (i.e., the combined leakage for the tubes with axial cracks in the WEXTEX region) plus the combined leakage developed by other alternate repair criteria (ARC), to remain below the maximum allowable SLB primary-to-secondary leakage rate limit such that the doses are maintained to less than a fraction of the 10 CFR 100 limits and also less than the General Design Criteria (GDC)-19 limits.

Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the proposed amendment create the possibility of a new or different kind of accident from any accident previously evaluated?

   Response: No.

   TVA's amendment request does not introduce any physical changes to the Sequoyah Unit 2 SGs. TVA's amendment request takes credit for how the tubesheet enhances the SG tube integrity in the WEXTEX region by precluding tube deformation beyond its initial expanded outside diameter and allows axial cracks in the WEXTEX region to remain in service if prescribed criteria are met. Removal of the existing primary water stress corrosion cracking (PWSCC) axial at dented tube support plate ARC incorporates the more conservative TS limit for SG tube plugging. A failure to meet SG tube integrity results in an SGTR. Because the circumferential cracks detected within the WEXTEX region are required to be plugged, it is highly unlikely that a W* tube would fail as a result of a circumferential defect. Therefore, a tube severance which would strike neighboring tubes and create a multiple tube rupture is not credible.

   The proposed change does not introduce any new equipment or any change to existing equipment. No new effects on existing equipment are created.

   Therefore, the proposed change does not create the possibility of a new or different kind of accident from any previously evaluated.

3. Does the proposed amendment involve a significant reduction in a margin of safety?

   Response: No.

   The amendment request maintains the structural margins of the SG tubes for both normal and accident conditions that are required by Regulatory Guide 1.121.

   For primarily axially oriented cracking located within the tubesheet, tube burst is precluded because of the presence of the tubesheet. WCAP-14797 defines a length, W*, of degradation free expanded tubing that provides the necessary resistance to tube pullout due to the pressure induced forces (with applicable safety factor applied). Application of the W* criteria will preclude unacceptable primary-to-secondary leakage during all plant conditions. The methodology for determining leakage provides for large margins between calculated and actual leakage values in the W* criteria.

   Plugging of the SG tubes reduces the reactor coolant flow margin for core cooling. Implementation of the proposed changes is expected to result in plugging of fewer tubes than with the current criteria. Thus, implementation of the proposed changes will maintain the margin of flow that may have otherwise been reduced by tube plugging.

It is concluded that the proposed changes do not result in a significant reduction of margin with respect to plant safety as defined in the Updated Final Safety Analysis Report or TSs.

Based on the above, TVA concludes that the proposed amendment does not involve a significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and accordingly, a finding of "no significant hazards consideration" is justified.

4.4 Conclusions

In conclusion, based on the considerations discussed above, (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

5.0 ENVIRONMENTAL CONSIDERATION

A review has determined that the proposed amendment would change a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10 CFR 20, or would change an inspection or surveillance requirement. However, the proposed amendment does not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluents that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed amendment meets the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed amendment.

6.0 REFERENCES

1) NRC letter to TVA dated May 3, 2005, "Sequoyah Nuclear Plant, Unit 2 - Issuance of Amendment Regarding Changes to the Inspection Scope For The Steam Generator Tubes (TAC No. MC5212) (TS-03-06)."

2) WCAP-14797, Revision 2, "Generic W* Tube Plugging Criteria for 51 Series Steam Generator Tubesheet Region WEXTEX Expansions," Westinghouse Electric Company, Madison, PA, March 2003 (Proprietary).

3) LTR-CDME-04-147, Revision 1, "Application of W* Alternate Repair Criteria to Sequoyah Unit 2," Westinghouse Electric Company, Madison, PA, February 2005 (Proprietary).

4) US NRC Generic Letter 2004-01, "Requirements for Steam Generator Tube Inspections," August 30, 2004.

ATTACHMENTS

1. Technical Specifications Page Markups
2. Bases Page Markups
3. Application of W* Alternate Repair Criteria to Sequoyah Unit 2 Cold Leg Tubes (Proprietary)
4. Application of W* Alternate Repair Criteria to Sequoyah Unit 2 Cold Leg Tubes (Non-Proprietary)
5. Westinghouse Proprietary Data Withholding Affidavit No. CAW-09-2548

ATTACHMENT 1

TENNESSEE VALLEY AUTHORITY
SEQUOYAH NUCLEAR PLANT (SQN)
UNITS 1 AND 2

PROPOSED TECHNICAL SPECIFICATION CHANGES (MARK-UP)

I. **AFFECTED PAGE LIST**

Unit 2

6-10c
6-10d

II. **MARKED PAGES**

See attached.

Gr	=	average growth rate per cycle length
NDE	=	95 percent cumulative probability allowance for nondestructive examination uncertainty (i.e., a value of 20 percent has been approved by NRC)

Implementation of these mid-cycle repair limits should follow the same approach as in TS items 6.8.4.k.c.1.a), .b), .c) and .d).

2. W* Methodology

The following terms/definitions apply to the W*.

a) Bottom of WEXTEX Transition (BWT) is the highest point of contact between the tube and tubesheet at, or below the top of tubesheet (TTS), as determined by eddy current testing.

for the hot leg tubesheet

b) W* Distance is the larger of the following two distances as measured from the TTS: (a) 8 inches below the TTS or (b) 7 inches below the bottom of the WEXTEX transition plus the uncertainty associated with determining the distance below the bottom of the WEXTEX transition as defined by WCAP-14797, Revision 2.

Service induced flaws identified in the W* distance shall be plugged on detection. Flaws located below the W* distance may remain in service regardless of size.

d. Provisions for SG Tube Inspections.

Periodic SG tube inspections shall be performed. 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, d.3, d.4, and d.5, below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG 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.

1. Inspect 100% of the tubes in each SG during the first refueling outage following SG replacement.

c) W* distance for the cold leg tubesheet is 10.5 inches below TTS

2. 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 SGs. No SGs shall operate for more than 24 effective full power months or one refueling outage (whichever is less) without being inspected.

3. If crack indications are found in any SG tube, then the next inspection for each SG 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.

4. GL 95-05 Voltage-Based ARC for TSP

   Indications left in service as a result of application of the TSP voltage-based repair criteria shall be inspected by bobbin coil probe every 24 effective full power months or every refueling outage, whichever is less.

   Implementation of the SG tube/TSP repair criteria requires a 100 percent bobbin coil inspection for hot-leg and cold-leg TSP intersections down to the lowest cold-leg TSP with known ODSCC indications. The determination of the lowest cold-leg TSP intersections having ODSCC indications shall be based on the performance of at least a 20 percent random sampling of tubes inspected over their full length.

5. W* Inspection

   and 20 percent of the inservice tubes in the cold leg tubesheet

   When the W* methodology has been implemented, inspect 100 percent of the inservice tubes in the hot-leg tubesheet region with the objective of detecting flaws that may satisfy the applicable tube repair criteria of TS 6.8.4.k.c.2.

e. Provisions for Monitoring Operational Primary-to-Secondary Leakage

l. <u>Component Cyclic and Transient Limit</u>

This program provides controls to track the FSAR, Section 5.2.1, cyclic and transient occurrences to ensure that components are maintained within the design limits.

6.9 REPORTING REQUIREMENTS

ROUTINE REPORTS

6.9.1 In addition to the applicable reporting requirements of Title 10, Code of Federal Regulations, the following reports shall be submitted in accordance with 10 CFR 50.4.

STARTUP REPORT

6.9.1.1 DELETED

6.9.1.2 DELETED

6.9.1.3 DELETED

ATTACHMENT 2

TENNESSEE VALLEY AUTHORITY
SEQUOYAH NUCLEAR PLANT (SQN)
UNITS 1 AND 2

CHANGES TO TECHNICAL SPECIFICATIONS BASES PAGES

I. AFFECTED PAGE LIST

Unit 2

B 3/4 4-3d
B 3/4 4-3e

II. MARKED PAGES

See attached.

APPLICABLE
SAFETY ANALYSIS (continued)

and cold leg

including a complete circumferential separation of the tube, is acceptable. As applied at Sequoyah Nuclear Plant Unit 2, the W* methodology is used to define the required tube inspection depth into the hot-leg tubesheet, and is not used to permit degradation in the W* distance to remain in service. Thus while primary to secondary leakage in the W* distance need not be postulated, primary to secondary leakage from potential degradation below the W* distance will be assumed for every inservice tube in the bounding SG.

c) Calculation of Operational Assessment (OA) Accident Induced Leakage

The postulated leakage during a Steam Line Break (SLB) shall be equal to the following equation:

Postulated SLB OA Leakage = ARC $_{GL\ 95\text{-}05}$ + Assumed Leakage $_{0''\text{-}8'' <TTS}$ + Assumed Leakage $_{8''\text{-}12'' <TTS}$ + Assumed Leakage $_{>12'' <TTS}$ + All other sources of accident induced primary to secondary leakage.

Where: ARC $_{GL\ 95\text{-}05}$ is the SLB OA leakage for predominantly axially oriented outside diameter stress corrosion cracking indications as determined from the methodology described in GL 95-05 as revised by Technical Specification Change 06-06.

for both the hot leg and cold leg tubesheet

Assumed Leakage $_{0''\text{-}8'' <TTS}$ is the postulated OA leakage for undetected indications in SG tubes left in service between 0 and 8 inches below the TTS.

for both the hot leg and cold leg tubesheet

Assumed Leakage $_{8''\text{-}12'' <TTS}$ is the conservatively assumed OA leakage from the total of identified and postulated unidentified indications in SG tubes left in service between 8 and 12 inches below the TTS. This is 0.0045 gpm multiplied by the number of indications. Postulated unidentified indications will be conservatively assumed to be in one SG. The highest number of identified indications left in service between 8 and 12 inches below TTS in any one SG will be included in this term.

for both the hot leg and cold leg tubesheet

Assumed Leakage $_{>12'' <TTS}$ is the conservatively assumed OA leakage for the bounding SG tubes left in service below 12 inches below the TTS. This is 0.00009 gpm multiplied by the number of tubes left in service in the least plugged SG.

When no PWSCC tube indications are identified in the cold leg tubesheet region the cold leg OA leakage is 0.0 gpm.

APPLICABLE
SAFETY ANALYSIS (continued)

All other sources of accident induced primary to secondary leakage is the primary to secondary accident induced OA leakage from all other degradation mechanisms other than the voltage based axial ODSCC at tube support plates repair criteria and W* leakage calculations as determined by the Operational Assessment.

d) Calculation of Condition Monitoring (CM) Accident Induced Leakage

The postulated leakage during a SLB shall be equal to the following equation and is performed for each steam generator:

Postulated SLB CM Leakage = ARC $_{GL\ 95\text{-}05}$ + Assumed Leakage $_{0''\text{-}8''\ <TTS}$ + Assumed Leakage $_{8''\text{-}12''\ <TTS}$ + Assumed Leakage $_{>12''\ <TTS}$ + All other sources of accident induced primary to secondary leakage.

Where: ARC $_{GL\ 95\text{-}05}$ is the SLB CM leakage for predominantly axially oriented outside diameter stress corrosion cracking indications as determined from the methodology described in GL 95-05 as revised by Technical Specification Change 06-06.

for both the hot leg and cold leg tubesheet

Assumed Leakage 0"-8" <TTS is the postulated CM leakage for indications detected in SG tubes between 0 and 8 inches below the TTS.

for both the hot leg and cold leg tubesheet

Assumed Leakage $_{8''\text{-}12''\ <TTS}$ is the conservatively assumed CM leakage from the total of identified and postulated unidentified indications in SG tubes left in service between 8 and 12 inches below the TTS. This is 0.0045 gpm multiplied by the number of indications.

for both the hot leg and cold leg tubesheet

Assumed Leakage $_{>12''\ <TTS}$ is the conservatively assumed CM leakage for the bounding SG tubes in service 12 inches below the TTS. This is 0.00009 gpm multiplied by the number of tubes left in service in the SG.

All other sources of accident induced primary to secondary leakage is the primary to secondary accident induced CM leakage from all other degradation mechanisms other than the voltage based axial ODSCC at tube support plates repair criteria and W* leakage calculations as determined by Condition Monitoring.

When no PWSCC tube indications are identified in the cold leg tubesheet region the cold leg CM leakage is 0.0 gpm.

The aggregate calculated accident induced primary to secondary SLB leakage from the application of all approved ARC (W* and voltage-based axial ODSCC at TSP) shall be reported to the NRC in accordance with Technical Specification 6.9.1.16.4. The combined calculated leak rate from all ARC and all other sources of accident induced leakage must be less than the accident induced primary to secondary leakage rate assumed in the SLB accident analyses.

LTR-SGMP-09-35 NP-Attachment

Tennessee Valley Authority

Application of W* Alternate Repair Criteria to Sequoyah Unit 2 Cold Leg Tubes (Non-Proprietary)

March 25, 2009

Westinghouse Electric Company LLC
P.O. Box 355
Pittsburgh, PA 15230-0355

Application of W* Alternate Repair Criteria to Sequoyah Unit 2 Cold Leg Tubes

1.0 INTRODUCTION

In 2005, a modification to the SQN-2 Technical Specifications was approved which applied the W* tubesheet region alternate repair criterion to the hot leg expanded tube in tubesheet length. The documents which provided the bases for the W* application were WCAP-14797-P, Revision 2, "Generic W* Tube Plugging Criteria for 51 Series Steam Generator Tubesheet Region WEXTEX Expansions," Reference 1.1, and LTR-CDME-04-147, Revision 1, "Application of W* Alternate Repair Criteria to Sequoyah Unit 2 (Proprietary)," Reference 1.2.

At the SQN-2, 2008 inspection, axial primary water stress corrosion cracking (PWSCC) indications were reported near the cold leg tube end on R1 C59 in SG4. This tube was inspected using a Plus Point (+Pt) coil due to bobbin coil reported bulge (BLG) signals higher in the tubesheet. The +Pt examination of the bulges reported no degradation. Two other tubes (R9 C53 and R14 C40, both in SG4) with BLG signals in the cold leg tubesheet were subsequently inspected using the +Pt coil. Degradation was not reported at the BLG locations or at the tube end regions for R9 C53 or R14 C40 in SG4. Previously, all Row 1 tubes at SQN-2 were plugged using roll plugs due to a PWSCC concern at small radius U-bends. These tubes were later deplugged and returned to service following U-bend heat treatment. The elevations of the indications on R1 C59 cold leg loosely coincide with the roll plug roll expansion region. The potential exists that additional Row 1 cold leg tube ends may also contain PWSCC, thus, TVA is proposing the application of the W* alternate repair criterion to the cold legs at SQN-2 to avoid unnecessary radiation exposure by plant workers and to perform inspection of and to avoid unnecessary plugging of those Row 1 tubes which may be found to contain PWSCC at the cold leg tack roll region.

TVA is proposing to modify the Sequoyah Unit 2 Technical Specifications 6.8.4.k.c.2.b, "W* Methodology," to define the hot leg and cold leg W* distances. Specifically, the proposed change will clarify the W* distance for the hot leg and add the W* distance for the cold leg. Specification 6.8.4.k.d.5 will be revised to include a 20% sample inspection using an inspection probe qualified for detection of the expected degradation modes of the cold leg tubes at the U2R16 outage commensurate with the specified cold leg W* distance. BASES Section B ¾.4.5, "Steam Generator (SG) Tube Integrity," item b) will be revised to include application of the W* alternate repair criterion to both the hot and cold leg tubes. Items c) and d) will be revised to include that the applicable W* leakage allowances will be applied to both hot and cold legs. Item d) will be revised to include provision that should no PWSCC indications be detected during the U2R16 cold leg inspection sample that leakage allowance for postulated indications below 12 inches below the cold leg top of tubesheet will not be provided for in the condition monitoring or operational assessment of primary to secondary leakage during faulted events.

The Sequoyah Unit 2 proposed change requires that any cold leg tube identified with service induced degradation above the tubesheet mid-plane elevation (10.5 inches below the cold leg top of tubesheet) must be repaired. This application is conservative compared to the analysis results of Reference 1.1, which develops a cold leg W* distance of 7.5 inches below the bottom of the WEXTEX expansion transition (BWT). Since Sequoyah proposes to repair any service induced degradation within the proposed W* distance (10.5 inches for the cold leg), this proposal is a conservative limited scope application of the complete W* methodology as described in Reference 1.1.

As a consequence of implementation, any degradation occurring below the W* distance may remain in service regardless of its axial or circumferential extent. The amendment will be based on portions of WCAP-14797-P, Rev. 2, entitled, "Generic W* Tube Plugging Criteria for 51 Series Steam Generator Tubesheet Region WEXTEX Expansions," Reference 1.1, and the following information developed herein. The W* analysis accounts for the reinforcing effect that the tubesheet has on the external surface of the steam generator tubes within the tubesheet region.

This amendment is requested to address Nuclear Regulatory Commission (NRC) GL 2004-01 (Reference 1.3) with respect to defined tube inspection depth below the top of tubesheet using supplemental inspection techniques qualified for flaw detection in expanded tubesheet conditions, such as rotating pancake coil (RPC) or array probes. This amendment is also requested to prevent the unnecessary plugging of potential indications at the cold leg tube end region, which, have no structural or leakage consequence. Thus, plugging of such indications would not support as low as reasonably achievable (ALARA) fundamentals.

Much of the technical discussion which follows is a reiteration of the technical bases supporting application of W* to the hot leg tubes, which inherently applies to the cold leg. New subject matter discussed includes updating of the hot leg indication summary since 2005, estimates of the potential number of cold leg PWSCC indications, and discussion related to issues resultant from NRC review of another tubesheet region alternate repair criterion developed for hydraulically expanded tubing. Discussions of issues raised during NRC review of other tubesheet region alternate repair criteria are included in Sections 4.3, 4.4, and 4.5.

REFERENCES

1.1 WCAP-14797, Rev. 2, "Generic W* Tube Plugging Criteria for 51 Series Steam Generator Tubesheet Region WEXTEX Expansions," Westinghouse Electric Company, Madison, PA, March 2003 (Proprietary).

1.2 LTR-CDME-04-147, Rev. 1, "Application of W* Alternate Repair Criteria to Sequoyah Unit 2," Westinghouse Electric Company, Madison, PA, February 2005 (Proprietary).

1.3 US NRC Generic Letter 2004-01, "Requirements for Steam Generator Tube Inspections," August 30, 2004.

2.0 SUMMARY and CONCLUSIONS

The information in this report demonstrates:

1) The information developed for the generic application of W*, Reference 1.1, is applicable to the cold leg of SG tubes at SQN-2.
2) The total leak rate from postulating all tubes in the bundle to have undetected indications that are through-wall for an extent of 360° at an elevation of 12 inches below the top of the tubesheet would be bounded by 0.3 gpm (assuming 3388 active tubes per SG) per leg to which W* is applied.
3) The number of undetected indications in the range of 8 to 12 inches below the top of the tubesheet can be conservatively estimated based on the number of indications detected in the range of zero to 8 inches.
4) The number of detected indications on the cold leg in the range of zero to 8 inches is expected to be zero or very small and the number of undetected indications in the range of 8 to 12 inches below the cold leg top of the tubesheet is expected to be even smaller.
5) The total leak rate from undetected indications in the range of 8 to 12 inches below the top of the tubesheet can be conservatively bounded by multiplying the number of predicted tubes with such indications by 4.5×10^{-3} gpm per tube.
6) The total leak rate from axial and circumferential indications in the range of 0 to 8 inches below the top of the tubesheet can be conservatively estimated for the Condition Monitoring evaluation by applying available flaw depth estimation techniques and calculating the leak rate using the models based on the performed leakage testing described herein for those eddy current indications judged to represent a 100% through-wall (TW) degraded condition.

Performing an RPC inspection of the cold leg tubes in the SQN-2 SGs to a depth of 8.5 inches below the top of the cold leg tubesheet or 7.5 inches below the bottom of the WEXTEX expansion transition is sufficient to assure the structural and leak rate integrity of the tube bundle in accord with industry and regulatory requirements. For the EOC-16 inspection, TVA will apply a cold leg inspection depth of 10.5 inches below the top of tubesheet. An initial sample of 20% of the cold leg active tubes will be performed in each SG at EOC-16. Inspection scope expansion will follow the guidance of Reference 2.1. Cold leg RPC inspection for the EOC-17 outage will be determined based on the EOC-16 results; if no degradation is reported at EOC-16, RPC inspection of the cold legs will not be performed at EOC-17, consistent with the guidance of Reference 2.1. If no cold leg PWSCC is detected at EOC-16, the Cycle 17 operational assessment will not include a leakage allowance for the cold leg.

REFERENCES

2.1 *Steam Generator Management Program, Pressurized Water Reactor Steam Generator Examination Guidelines: Revision 7.* EPRI, Palo Alto, CA: 2007. 1013706

3.0 W* BACKGROUND

Existing plant Technical Specification tube repair/plugging criteria apply throughout the tube length and do not take into account the reinforcing effect of the tubesheet on the external surface of an expanded tube. The presence of the tubesheet constrains the tube and complements tube integrity in that region by essentially precluding tube deformation beyond the expanded outside diameter (OD). The resistance to both tube rupture and tube collapse is significantly enhanced by the tubesheet. In addition, the proximity of the tubesheet in the expanded region significantly reduces the leakage of through-wall tube cracks. Based on these considerations, the establishment of alternate repair criteria to the portion of tubing expanded by Westinghouse explosive tube expansion (WEXTEX) is supported by testing and analysis results included in Reference 1.1.

For Westinghouse Model 51 Series steam generators with WEXTEX expansions at SQN-2, the full depth tube-to-tubesheet expansion can be defined as follows. From the lower tube end and extending upward for a length of approximately 2.75 inches is a region expanded by a tube mechanical roll expansion process. From the top of the rolled expansion region to the vicinity of the top of the tubesheet (TTS), the expansion joint was produced by the WEXTEX process. The resulting full depth tube-to-tubesheet expansion can be considered as four distinct areas. These are described in Reference 1.1 as:

1. The Roll Region – The region of tube which has been expanded by the tube rolling process. This region extends from the bottom of the tube to approximately 2.75 inches above the bottom of the tube.
2. The Roll Transition – The portion of the tube which extends from the roll expanded region of the tube to the initially unexpanded region, and which is subsequently expanded by the WEXTEX process.
3. The WEXTEX Region – The portion of the tube expanded by the explosive expansion process to be in contact with the tubesheet. This region starts at the roll transition and extends to the WEXTEX transition in the vicinity of the top of the tubesheet.
4. The WEXTEX Transition – The portion of the tube which acts as a juncture between the WEXTEX region and the unexpanded region of the tube. The region starts at the top of the explosively expanded region and extends for approximately 0.25 inches.

The alternate SG tube repair criteria referred to as W* were developed by Westinghouse (and have been licensed to varying extents at other plants) to permit tubes with predominantly axially oriented primary water stress corrosion cracking in the WEXTEX and hardroll regions to remain in service. The W* analysis determined the W* length as measured from the bottom of the tube explosive expansion transition that would permit flaws below that length to remain in service and based on the assurance that adequate strength is available to resist the axial pull out loads experienced within the tubesheet during all plant conditions.

The following definitions apply with regard to describing the W* criteria:

BWT – The bottom of the WEXTEX Transition as defined in Reference 1.1, as approximately 0.25 inches from the top of the tubesheet.

W* length – The maximum length of tubing below the bottom of the WEXTEX transition (BWT) which must be demonstrated to be non-degraded and is defined in Reference 1.1, Section 4.0 as 7.5 inches below the bottom of the WEXTEX transition on the cold leg side.

W* distance – The distance from the top of the tubesheet to the bottom of the W* length including the distance from the top of the tubesheet to the BWT and measurement uncertainties.

The W* analysis provides the basis for tubes with any form of degradation below the W* length to remain in service. The presence of the surrounding tubesheet prevents tube rupture and provides resistance against axial pull out loads during normal and accident conditions as discussed in Reference 1.1. In addition, any primary-to-secondary leakage from tube degradation below the W* length is determined to be acceptably low as discussed in Section 4.0 of this report. Both steam generator tube structural and leakage integrity will be shown to meet the required performance criteria of Reference 3.1 and, thus, the necessary regulatory criteria as defined below.

General Design Criteria (GDC) 1, 2, 4, 14, 30, 31, and 32 of 10 CFR 50, Appendix A, define requirements for the reactor coolant pressure boundary (RCPB) with respect to structural and leakage integrity.

General Design Criterion (GDC) 19 of 10 CFR 50, Appendix A, defines requirements for the control room and for the radiation protection of the operators working within it. Accidents involving the leakage or burst of SG tubing comprise a challenge to the habitability of the control room.

10 CFR 50, Appendix B, establishes quality assurance requirements for the design, construction and operation of safety related components. The pertinent requirements of this appendix apply to all activities affecting the safety related functions of these components; these include, in part, inspecting, testing, operating and maintaining Criteria IX, XI and XVI of Appendix B as applied to the SG tube integrity program defined by NEI 97-06, Rev. 1 "Steam Generator Program Guidelines," Reference 3.1.

10 CFR 100, Reactor Site Criteria, established reactor-siting criteria, with respect to the risk of public exposure to the release of radioactive fission products. Accidents involving leakage or burst of SG tubing may compromise a challenge to containment and therefore involve an increased risk of radioactive release. Sequoyah Unit 2 is licensed for the use of an alternate source term in accordance with 10 CFR 50.67 for some design basis accidents.

Under 10 CFR 50.65, the Maintenance Rule, licensees classify steam generators as risk significant components because they are relied upon to remain functional during and after design basis events. SGs are to be monitored under 10 CFR 50.65 (a) (2) against industry established performance criteria. Meeting the performance criteria of NEI 97-06, Rev. 1, provides reasonable assurance that the SG tubing remains capable of fulfilling its specific safety function of maintaining the reactor coolant pressure boundary.

The SG performance criteria as defined in NEI 97-06, Rev. 1 (Reference 3.1) identify the standards against which performance is to be measured.

As discussed in more detail in Section 4.0 of this report, the generic W* analysis contained in Reference 1.1 is applicable to the Sequoyah Unit 2 SGs and defines the maximum cold leg W* length for pull out resistance as 7.5 inches below the bottom of the WEXTEX transition for Zone B tubes, and 5.5 inches below the bottom of the WEXTEX transition for Zone A tubes. The maximum non-destructive examination (NDE) uncertainty on the W* distance in Reference 1.1 is 0.12 inch. Therefore, the required Technical Specification inspection distance below the top of the tubesheet, or bottom of the WEXTEX transition, whichever is lower, is 7.62 inches. In order to expedite NRC review, TVA will apply a cold leg W* RPC inspection distance of 10.5 inches below the cold leg top of tubesheet. Any observed degradation within the observed inspection distance will be plugged. Consistent with previous W* applications, if degradation in the vicinity of the applied inspection distance is observed, the additional elevation uncertainty associated with crack tip measurement per Reference 1.1 will be applied to determine the continued operability of the subject indication.

REFERENCES

3.1 NEI 97-06, Rev. 2, "Steam Generator Program Guidelines," Nuclear Energy Institute, Washington, DC, May 2005.

4.0 APPLICABILITY OF WCAP-14797, REV. 2, TO SEQUOYAH UNIT 2

4.1 BACKGROUND INFORMATION

As noted above, the W* length is the length of sound engagement of the tube within the tubesheet such that the available reaction force resisting is at least three times greater than the applied force attempting to pull the tube from the tubesheet. The value of W* is determined using applicable performance criteria relative to tube burst, expulsion from the tubesheet in this case, and relative to allowable leakage, relative to that established for alternate repair criteria (ARC). The structural performance criteria are that tube burst will not occur with a margin of 3 during normal operation and 1.4 during the most severe faulted event, a postulated steam line break (SLB) for Sequoyah Unit 2.

Applied Load

The applied force comes from the internal pressure in the tube. At the U-bend, there is a component of the primary-to-secondary differential pressure acting in the axial direction. For the development of the criteria it is also assumed that the tube is severed in the tubesheet so that the differential pressure acts on the entire cross-sectional area of the tube as calculated using the expanded OD of the tube. The applied force, F_A, is determined from the applied pressure, ΔP, area, A, and the outside diameter, D_o, as

$$F_A = \Delta PA \text{ where, } \quad A = \frac{\pi}{4} D_o^2 \tag{1}$$

Here, ΔP is the difference between the primary, P_P, and secondary pressure, P_S, at the top of the tubesheet, i.e., $P_P - P_S$.

Reaction Load

The reaction load in developing the W* length arises from friction between the tube and the tubesheet within the tubesheet hole. The friction force is the product of the normal force between the tube and the tubesheet and coefficient of friction between the tube and the tubesheet. The normal force arises or is affected by four sources:

1. The residual preload from the expansion process,
2. Differential thermal expansion between the tube and the tubesheet,
3. Resultant pressure in the tube within the tubesheet, and
4. Dilation of the tubesheet holes from bowing of the tubesheet.

The first three items result in a compressive normal force between the OD of the tube and the inside diameter (ID) of the tubesheet hole. The last item results in a reduction of the normal force near the top of the tubesheet and an increase in the normal force below the tubesheet neutral axis. It is noted that a lateral load applied to the center of the tube span above the TTS would tend to result in a slight lateral contraction in the axial direction. An analysis of the geometry of deflection shows that the axial contraction is a small fraction of the lateral deflection and the bending load that would be developed at the top of the tubesheet would act to bind the tube tighter in the tubesheet hole. On this basis, the action of lateral flow loads can be neglected from further consideration.

*Determination of W**

The calculation performed is to find the length, W*, that makes the following equality true between the resisting force on the left and the applied force on the right,

$$\mu\left(N_X + N_T + N_P + N_D\right) = \Delta P\ A \tag{2}$$

where N_X = The residual normal force from the expansion process,
N_T = The normal force from the differential thermal expansion,
N_P = The normal force due to the resultant pressure in the tube,
N_D = The normal force resulting from dilation of the tubesheet hole,
μ = The coefficient of friction between the tube and the tubesheet.

The resisting forces are due to the interface pressure between the tube and the tubesheet. The actual force is the product of the interface pressure times the effective area of contact, the circumference of the tube times the length of contact. Conservative uncertainty adjustments are then made to the length of contact to determine W*. The diameter of the tube is constant, so an expression for the force per unit length is used and solved for the length, *L*. This means that each force term must be replaced by force per unit length term.

The solution for W* is then,

$$W = \frac{\Delta P\ A}{\mu\left(F_X + F_T + F_P + F_D\right)} \tag{3}$$

where *W* stands for the W* length and the letter *F* stands for the force per unit length of engagement. Each force per unit length term is then replaced by a corresponding pressure times circumference term, i.e.,

$$W = \frac{\Delta P\ A}{\mu\left(P_X + P_T + P_P + P_D\right)\pi D_o} \tag{4}$$

where D_o is the outside diameter of the expanded tube. Substituting for the cross-sectional area yields,

$$W = \frac{\Delta P\ D_o}{4\mu\left(P_X + P_T + P_P + P_D\right)} \tag{5}$$

for the determination of W, sans adjustments for uncertainties in measurement and end effects where the assumption of a severed tube has been made. The following points are to be noted:

1. The applied load term, the numerator, is affected by changes in the operation of the plant. The value used for the generic document is the same as that for the plant specific application at Sequoyah Unit 2, hence the W* length would be expected to be the same as that for the generic application.
2. The residual expansion pressure, P_X, is not affected by changes in the operation of the plant.
3. The thermal expansion term, P_T, is affected by changes in the hot leg and cold leg temperatures, T_{hot} and T_{cold}. The hot leg and cold leg temperatures at Sequoyah Unit 2 are greater than the value used for the generic determination, hence the value of W* for use at Sequoyah Unit 2 should be less than the generic value.
4. The differential pressure term, P_P, is affected by changes in the primary or secondary pressure. The differential pressure term used for the Sequoyah Unit 2 analysis is less than the generic analysis; therefore, the value of W* for use at Sequoyah Unit 2 should be less than the generic value.
5. The dilation term, P_D, is also affected by changes in the primary or secondary pressure. The differential pressure acting across the tube sheet is the same as in the generic report. It is noted that different differential pressure conditions were used for the determination of the different contributing load terms for the analysis of the generic report. This is an acceptable approach since the structure remains elastic when the terms are superimposed and is discussed in the following section.

4.2 APPLICATION OF WCAP-14797-P, REV. 2, TO SEQUOYAH UNIT 2

The determination of the non-degraded tube length considers the residual preload capability of the tube expansion process, the thermal tightening effects due to thermal expansion coefficient differences between the tube and the tubesheet material, pressure tightening effects, and loss of preload due to tubesheet bow effects. The residual preload inherent in the expansion in the expansion process is independent of differences between analysis and plant conditions. The generic analysis uses a cold leg temperature of 525°F, whereas the current SQN-2 cold leg operating temperature is approximately 544°F (Reference 4.1). Therefore, the generic analysis includes less thermal tightening contribution than the actual condition within the steam generators. The generic analysis uses a secondary side steam pressure of 900 psia for evaluation of pressure tightening effects whereas the current secondary side steam pressure is 834 psig (849 psia). This steam pressure results in a smaller primary-to-secondary pressure differential for the generic analysis condition compared to the SQN-2 condition. Therefore, the generic analysis considers about 5.0% less pressure tightening contribution than the actual condition within the SQN-2 steam generators. The generic analyses also uses a steam pressure of 760 psia (1490 psi differential pressure across the tubesheet) for evaluation of end cap loading and tubesheet bow effects whereas the current SQN-2 differential pressure across the tubesheet is 1401 psi, thus the generic analysis is about 6.0% more conservative than the current SQN-2 conditions. Assumed normal operating steam pressure also influences the analysis with regard to defining the applied end cap load that acts to push the postulated separated tube out of the tubesheet hole. Moreover, the internal steam pressure losses due to moisture separation will result in a slightly higher steam pressure within the steam generator. Therefore, the generic analysis includes greater end cap loading compared to the actual conditions within the SQN-2 steam generators. This end cap load must be reacted by the net residual contact load. As the end cap load is reduced, the non-degraded tube length is also reduced compared to the generic analysis.

Based on the above, it is expected that the SQN-2 specific W* should be less than the generic value because of the net effect of the changes. The independent considerations lead to the results similar to those presented in the Reference 1.1. Table 4-1 summarizes the comparison of Sequoyah Unit 2 operating parameters to those considered in the generic report.

4.3 RECENT INVESTIGATIONS OF COEFFICIENT OF THERMAL EXPANSION

During NRC review of recent license amendment requests for other model SGs, the applied coefficients of thermal expansion (CTE) for the SA-508 tubesheet material and Alloy 600 tube material were questioned. Reference 4.2 describes the results of a testing program which concluded that for the large sample of test data prepared, that the average of the SA-508 data was slightly reduced compared to the ASME Code value and the average of the Alloy 600 data was slightly increased compared to the ASME Code value. Thus, use of Code values is conservative for the W* application per WCAP-14797, Rev 2, as effects of thermal expansion of the tube hole and tube would be conservatively influenced.

4.4 RECENT INVESTIGATIONS OF DIVIDER PLATE STRUCTURAL ANALYSES

4.4.1 Summary

Cracking has been observed in the heat affected zone of the stub runner to divider plate welds in foreign SGs. While no such cracking has been reported in US SGs, similar inspection has not been performed. The foreign SG manufacturer has not provided specific information regarding the chemical composition of the weld material thus no conclusive determination of the susceptibility difference between weld filler metal used in foreign SGs and weld filler metal used in US SGs can be made. The cracks appear to be the result of combined primary water stress corrosion cracking (PWSCC) and mechanical fatigue. Degradation of the divider plate to stub runner connections can affect the calculated deflection of the tubesheet due to pressure loads. This degradation may affect any analysis that depends upon the divider plate to limit the vertical displacement of the tubesheet as well as any analysis that takes credit for a divider plate factor. However, an updated analysis, finite element modeling, and historical data all show that the actual constraint provided by the divider plate and the divider plate connections to the tubesheet and channelhead, is greater than was typically assumed in analyses prior to 2006. Therefore, divider plate assumptions, and divider plate factors, assumed in historical Westinghouse analyses supporting the original W* structural analysis remain conservative and appropriate for assumed degraded divider plate to stub runner welds. The following discussions summarize these analyses.

4.4.2 Background

Westinghouse steam generator (SG) models have a divider plate in the lower steam generator complex. The divider plate separates the hot and cold legs of the steam generator and diverts the incoming reactor coolant flow from the hot leg plenum into the steam generator tubes. The lower steam generator complex consists of the channelhead (CH), the tubesheet (TS), the lower shell (aka, "Stub Barrel" or SB) and the divider plate (DP). See Figure 4-1 for an illustration of the typical lower steam generator geometry. The divider plate is connected to the channelhead and the primary face of the tubesheet via the stub runner. The divider plate is installed in the steam generator after the channelhead to tubesheet connections are made. The connection between the tubesheet and the divider plate is made via a "stub runner", which is a metal strip welded to the primary face of the tubesheet. The stub runner (SR) is typically 2 inches wide, with a height of 2 to 5 inches (depending on the SG model), and runs the full diameter of the primary tubesheet face. The divider plate, stub runner, channelhead and tubesheet meet at the edges of the lower complex at a triple point. See Figure 4-2 for a typical arrangement. The stub runner and divider plate were not considered to be significant structural components and a wide range of configurations, dimensions and compositions exist in the domestic fleet.

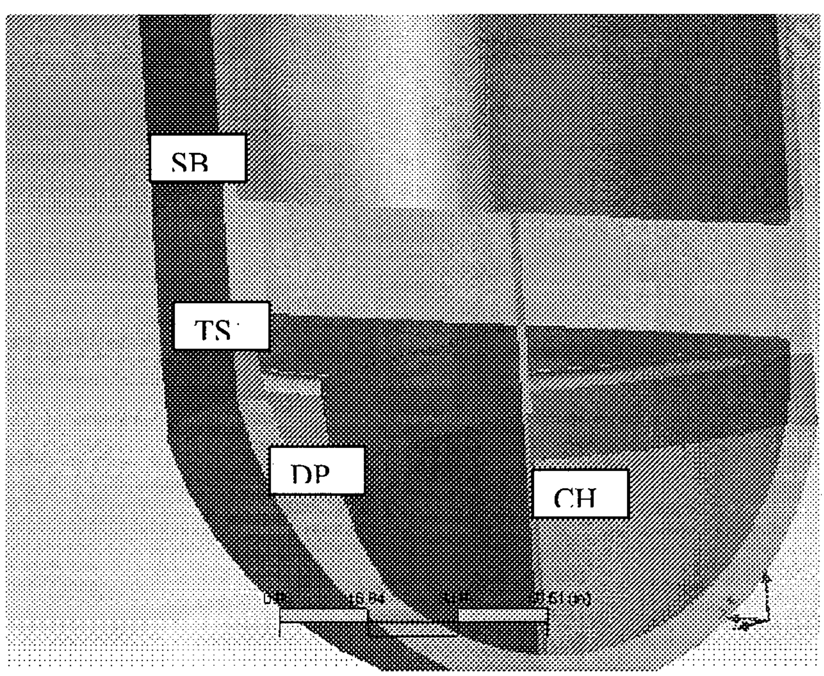


Figure 4-4: Typical Lower Complex Arrangement for Westinghouse Model SG. SB = Stub Barrel, TS = Tubesheet, DP = Divider Plate, CH = Channelhead.

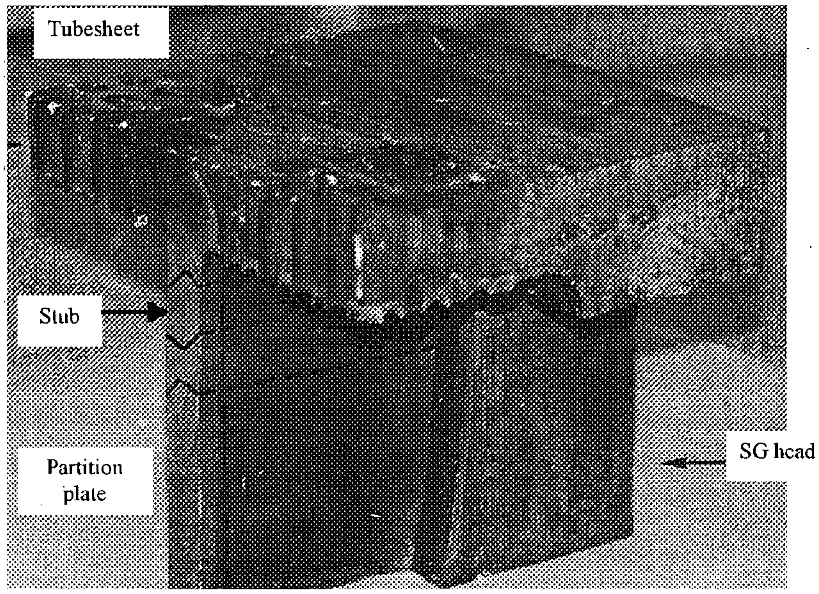


Figure 4-5: Destructive Examination Specimen from Existing SG Showing Triple Point Connections.

The purpose of the stub runner is to facilitate final assembly and welding between the tubesheet and divider plate and to protect the tube end welds and cladding in the vicinity of the divider plate from the high temperatures during welding of the divider plate. The divider plate in the Model F, Model D5, Model 44F and Model 51 type steam generators is made from Alloy 600 (ASME SB-168) (Reference 4.3). The weld material for the divider plate and stub runner connections is Alloy 82/182 weld material. Most weld procedures permit the use of either Alloy 82 wire (GTA welding) or Alloy 182 electrodes (shielded metal arc welding). Alloy 182 is more susceptible to PWSCC than Alloy 82 because of the lower chromium content. It is usually not possible to ascertain which weld material was used without referring to the specific shop welding logs (Reference 4.4). The channelhead to divider plate welds are heat treated. The welds between the stub runner and the tubesheet are typically heat treated. The welds between the divider plate and the stub runner are not heat treated.

Cracks have been observed in the weld material and divider plate material in the heat affected zone (HAZ) of steam generators in the foreign fleet. Cracks have been observed and measured with both ultrasonic inspection (UT), visual inspection (VT), and with dye penetrant inspection (Reference 4.5). Cracks have been observed on both the cold leg face of the divider plate and the hot leg face of the divider plate (Reference 4.6). The largest reported crack that has been observed in the foreign fleet is approximately 6 feet long (Reference 4.7). The deepest reported crack that has been observed in the HAZ of the divider plate to stub runner welds of the foreign fleet is approximately 0.25 inches deep (Reference 4.3). See Figure 4-3 for an example of a typical small divider plate crack in the heat affected zone. As of December 2008, no domestic plant has performed the same kind of VT/UT divider plate inspections as in the foreign fleet. No standard or guideline for inspection or repair for a crack in the divider plate connections exists for the domestic fleet. It is possible that the same level of degradation in the divider plate to stub runner welds could exist in the domestic fleet.

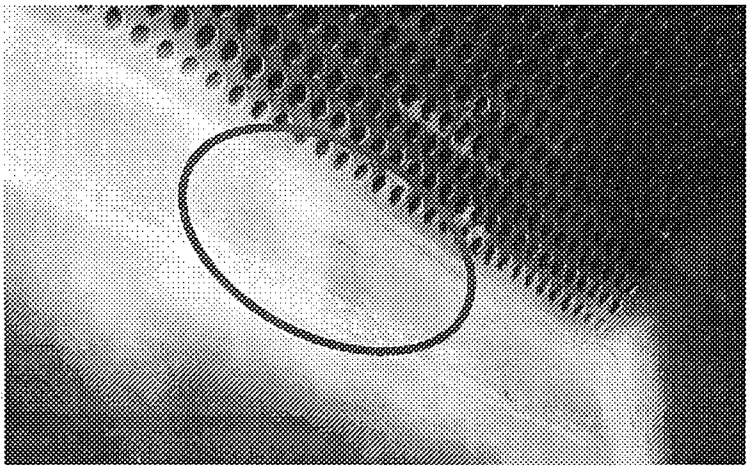


Figure 4-6: Observed Cracking in the Divider Plate and Stub Runner Region in a Retired Ringhals SG. (Red oval added to high light visible cracking region)

Although the divider plate it not a primary pressure boundary or a significant structural component there are some SG related analyses that do take credit for the presence of the divider plate and its structural connection to the tubesheet. These analyses vary from SG model to SG model and may include: mechanical tube plug design and qualification, tube sleeving installation, transient effects and accident analysis in the affected loop, and alternate repair criteria that require tubesheet displacements as an input. The most common way that an analysis will take credit for a divider plate is in the reduction of vertical and radial tubesheet displacements. This reduction is captured in a "divider plate factor" which compares the calculated displacements of a tubesheet without a DP present to the calculated displacements of a tubesheet with the DP present. The ratio of the tubesheet displacements for the two different cases is used to define a factor that can decrease the tubesheet displacements that are calculated from an axisymmetric finite element analysis (FEA). The typical value of the divider plate factor used in historical analysis involving the lower SG complex is 0.76. A value of 0.76 means that the pressure induced tubesheet deflections are assumed to be reduced by 24% due to the vertical connection between the tubesheet and the divider plate. The connections between the channelhead and the tubesheet were excluded from these analyses because the relationship between the pressure induced tubesheet deflections and the channelhead/divider plate structure was difficult to accurately represent using simple, linear equations. Therefore, most historical analyses have assumed that a divider plate factor of 0.76 was conservative and ignored the connections between the divider plate and the tubesheet.

The degradation of the divider plate to stub runner welds is the subject of an on-going Electric Power Research Institute (EPRI) program. The first and second phases of the program concluded that:

1. The limiting model of SG in the domestic fleet is a Westinghouse Model 51 (Reference 4.3).

2. Although deterioration of the SR weld was possible, the constraint offered by the DP when the upper five (5) inches of the DP and SR (encompassing the HAZ) are removed, still limited the deflections of the TS (Reference 4.3).

3. DP cracking was not a significant safety concern with respect to loss of coolant accident (LOCA) conditions or design basis accident (DBA) conditions in the event that a fully degraded weld between the SR and DP was to occur, and then open up a flow path between the hot leg and cold leg plenums in the channelhead bypassing the SG tubes (Reference 4.8).

4. The divider plate factor used to reduce the calculated tubesheet displacements, assuming an intact divider plate, in structural analyses prior to 2006 was 0.76. These analyses assumed the divider plate was not attached to the channelhead. The divider plate factor that can be assumed if the upper five (5) inches of the divider plate, stub runner, and heat affected zone were to be completely removed from the lower SG complex, with attachment between the divider plate and channelhead, is 0.64 (Reference 4.3).

Phase II of the EPRI program is scheduled to conclude in 2009. The current results indicate that a fully degraded divider plate to stub runner connection is not a safety significant condition with respect to accident operating conditions in an affected SG. This is because the potential for blow through from the crack opening area of a fully degraded divider plate to stub runner weld (100% of the divider plate length and 100% of the weld thickness) does not adversely affect the performance of the SG generator during a design basis transient or LOCA. The limiting crack opening area calculated for this analysis was 16.00 in^2 (Reference 4.8) and occurred during the bounding operational pressure difference for a main feedline break ($\Delta P = 2650$ psi). The current results also show that it is conservative to assume a divider plate factor of 0.76 to limit the tubesheet displacements because the worst case divider plate degradation is capable of providing a divider plate factor of 0.64.

4.4.3 Conclusions

The cracking and degradation identified in the foreign fleet might occur in the domestic fleet. However, the worst case degradation of the entire divider plate to stub runner weld being degraded is bounded by results published in an EPRI report (Reference 4.3). Further, the potential effects of a fully degraded divider plate to stub runner weld do not significantly affect the performance of a steam generator during design basis accident or LOCA conditions (Reference 4.8). The structural effect of a degraded divider plate to stub runner weld is bounded by the divider plate factor assumed by Westinghouse in tubesheet analyses prior to 2006 (Reference 4.3). Therefore, it is appropriate and conservative to consider a divider plate factor of 0.76 to reduce tubesheet displacements and further modification of steam generator operating criteria for the effect of design basis accidents or LOCA is not required.

4.5 IMPACT OF NRC REVIEW OF H* ALTERNATE REPAIR CRITERION UPON SQN-2 W* APPLICATION

During NRC review of the proposed H* alternate repair criterion (applicable to hydraulically expanded tubing) numerous issues were discussed between the NRC and the industry. During a telecom on 2/10/2009, NRC requested that two issues be considered by the TVA cold leg W* license amendment request. These issues are:

- Full Bundle versus Single Tube Analysis
- Applicability of H* crevice pressure test data

The full bundle analysis refers to sensitivity of the W* analysis to variations about the mean ASME Code values in material properties (i.e., coefficient of thermal expansion and modulus of elasticity).

The original W* (and H*) assumptions regarding pressure within the tube-to-tubesheet crevice was leakage into the crevice would flash to steam producing two-phase flow and thus secondary pressure would be applied to the tube hole and tube OD. This crevice pressure may affect the W* pull out analysis.

4.5.1 Full Bundle versus Single Tube Analysis

To compare the sensitivity of the W* calculation to variances in material properties, the current plant temperatures were applied with the current steam pressure minus a 15 psi allowance for steam pressure loss due to future plugging. A divider plate factor of 0.64 was applied as updated models have shown the original analysis to be quite conservative. The divider plate factor of 0.64 is associated with results of similar tubesheet deflection analyses which model disconnection between the tubesheet and divider plate but have included the channelhead stiffness as described by Section 4.4. An updated deflection model was applied which included anisotropic material properties and a finer finite element mesh model than the model described by WCAP-14797, Rev 2. This model was developed for the Model 51F SG, which has the same geometry as the Model 51, including the same tube hole dimensions and pitch. The deflections calculated for the unit loading case were scaled based on the evaluated temperature and the reference temperature assumed in the model. The reference case identified below is calculated using the updated deflection model, with coefficient of thermal expansion (CTE), and Young's Modulus values consistent with WCAP-14797, Rev 2.

For the reference case of:

T-hot = 611°F
T-stm = 524°F
P-stm = 818 psig
Divider Plate Factor (DPF) = 0.64, W* = 3.90 inch.

Sensitivity cases were calculated using 1) a reduction in the tube CTE of 2.33%, and 2) an increase in the tubesheet CTE of 1.44%. The impacts upon the calculated W* dimension were combined using a square root of sum of squares approach. Table 4-2 presents the results of this analysis and includes the W* distances provided by WCAP-14797 Rev 2 for comparison. For the cold leg normal operating case the current plant T-cold of 544°F was applied. A DPF of 0.64 was used for all cases. It should be noted that the values presented in Table 4-2 are calculated for the limiting radial location. A more appropriate comparison should include the mean W* distance for the tubesheet, not a W* distance represented by the limiting radial location. This value (based on the mean W*) should be compared with the WCAP-14797, Rev 2 values.

The results of this study (Reference 4.9) show that for the W* distance for tube and tubesheet CTE adjusted in the conservative direction at 1 standard deviation, combined by the square root of the sum of squares (SRSS), that the calculated distances remain bounded by the original analysis values for the hot leg, cold leg, and during faulted conditions. Note that the W* distance is calculated for the limiting radial location of the tubesheet based on the deflection analysis. Thus the W* distances of Table 4-2 are calculated for the *worst case deflection of the entire SG.* If the W* distance for the mean tubesheet deflection is applied, which would represent the most appropriate input for assessment of sensitivities, would result in much smaller nominal condition W* values.

The results of scaling the FEA outputs according to the applied temperature have substantial impacts upon the analysis. The original FEA results considered tubesheet deflections at a single temperature, 600°F. The original W* analysis of WCAP-14797, Rev 2, did not include scaling of the FEA output to account for temperature differences between the evaluated temperature and the reference temperature of the FEA. Thus for the hot leg condition, a slightly larger tubesheet deflection would be expected whereas for the cold leg, a smaller tubesheet deflection would be expected, based on the CTE applied at the evaluated temperature and stiffness of the tubesheet complex at the evaluated temperature. Thus, as shown on Table 4-2, the *cold leg* W* distance is now shorter than the hot leg W* distance, but both remain bounded by the W* distances provided by WCAP-14797, Rev 2.

4.5.2 Effect of Crevice Pressure Tests Upon W* Analysis

Pressure testing was performed on 11/16 inch OD hydraulically expanded tube in tubesheet collar specimens. In this testing, a 9.0 inch long hydraulically expanded tube length was used in a 14 inch long tubesheet simulant collar. The tube above the collar (secondary side) was weld plugged. Pressurized fluid was supplied to the tube by a welded pressure fitting. Drilled holes in the tube wall located below the hydraulically expanded length provided for direct fluid communication with the tube-to-tubesheet crevice. Pressure taps were located on the tubesheet collar at 7.5, 5.5, 4.5, 3.5 and 1.5 inches below the top of collar, or approximately 2, 4, 5, 6, and 8 inches above the bottom of the hydraulically expanded length. These tests indicate that the pressure in the crevice was elevated compared to the secondary side pressure and that the fluid remained in a liquid state up to an elevation near the secondary side elevation. The original assumption inherent to the W* (and other tubesheet region alternate repair criterion) criterion is that the pressure within the crevice is equal to the secondary side crevice and that any leakage within the crevice would be a two-phase flow condition. Leakage data was measured, however, this data is not utilized by the H* alternate repair criterion. This testing was performed for hydraulically expanded tubes. This condition is systematically different from an explosively expanded tube condition. In particular, the interface between the tube and tubesheet in the as-produced condition is dramatically different and is confirmed by a comparison of leak rate data for the two configurations.

Comparison of WEXTEX and Hydraulically Expanded Tubing Leak Rates

Room temperature leakage testing for the hydraulically expanded tubing indicates an average leak rate of [ ]a,c,e gpm for a pressure differential of 1910 psi and [ ]a,c,e gpm for a pressure differential of 2650 psi for a crevice length of 16.5 inches. A conversion of 72000 drops per gallon was applied to develop these values. In comparison, the 7/8 inch OD tube WEXTEX leak rate data indicates an average leak rate of [ ]a,c,e gpm at a pressure differential of 1620 psi and crevice length of 2.2 inches. Thus for similar pressure differential conditions (1620 versus 1910 psi), the hydraulically expanded tube leak rates are about [ ]a,c,e times greater with a crevice length which is 7.5 times the crevice length of the WEXTEX specimens. If the WEXTEX leak rate is adjusted by the circumference ratio of the two tube sizes used (because the available flow area is a function of diameter), the equivalent WEXTEX leak rate would be approximately [ ]a,c,e gpm, and if the crevice length effect is linearly applied, would be approximately [ ]a,c,e gpm, or about [ ]a,c,e times less than the hydraulically expanded tube leak rates. The ratio of the average loss coefficient values (W*/H*) is 36 for these data sets.

Elevated temperature testing shows an even greater disparity between the two designs. The average elevated temperature leak rate for the 11/16 inch OD specimens at 2650 psi differential pressure is [ ]a,c,e gpm for a 16.5 inch crevice length whereas the average leak rate for the 7/8 inch OD WEXTEX specimens is [ ]a,c,e gpm for a 2.2 inch crevice length. If the adjustments for circumference and crevice length are included, the adjusted WEXTEX leak rate for comparison purposes is [ ]a,c,e gpm, or about [ ]a,c,e times less than the hydraulically expanded tubes. The ratio of the average loss coefficient values (W*/H*) is 231 for these data sets.

Clearly there are systematic differences between the two expansion processes with regard to residual contact pressure due to the expansion process and with regard to effective contact pressure at elevated temperature conditions.

Also, the room temperature and elevated temperature hydraulically expanded tubing average leak rates are similar; [ ]a,c,e gpm at ΔP =1910 psi, [ ]a,c,e gpm at ΔP = 2650 psi, respectively, for room temperature and elevated temperature. The W* leak rate data for the 2.2 inch crevice length condition shows the elevated temperature leak rate data at a pressure differential of 1620 psi is roughly [ ]a,c,e times less for the elevated temperature case than the room temperature case. Clearly the interaction between the tube and collar at both room temperature and elevated temperature conditions is dramatically different between the two processes. As the WEXTEX joint is inherently tighter than the hydraulically expanded joint the resistance to flow is also greater. This resistance can only result in a larger pressure differential per unit length for equal flow rate conditions. Thus, it can be concluded that pressure conditions within the crevice region are not similar between hydraulically expanded and explosively expanded tubing, and application of the hydraulically expanded tubing crevice pressure testing results to explosively expanded tubing is without basis.

The hydraulically expanded elevated temperature tube leak testing shows that the leak rates were increased with increasing primary-to-secondary pressure differential. However, for the WEXTEX leak testing, the leak rates were constant over the range of tested pressure differentials, 1620, 2100, and 2650 psi. Leakage flow can be considered analogous to electric current, where voltage is proportional to the product of current and resistance. For leakage flow, pressure differential is proportional to the product of flow rate and loss coefficient. For the hydraulically expanded samples tested both at room temperature and elevated temperature, leak rate increases with increasing pressure differential. Evaluation of the proportional change in pressure differential is roughly equal to the proportional change in leak rate summed with the proportional change in loss coefficient. This suggests a change in the contact condition or flow area of the crevice with changing pressure differential. This change in contact condition or area is resultant from the tightening of the joint with increasing pressure differential.

For the W* specimens the leak rate remained constant with increasing pressure differential. Thus, the resistance to flow is proportionally increased and the change in resistance is then greater for the W* specimens for similar changes in primary-to-secondary pressure differential. Thus for the W* specimens, it can be concluded that the resistance across a unit length of crevice, and thus differential pressure across this unit length, must change similarly. This was not observed from the H* crevice pressure testing. For normal operating and faulted condition primary to secondary pressure differentials, the ratio of primary pressure to crevice pressure was similar over the pressure tap locations for both conditions.

If the tube hole and tube are examined on a microscopic level, the tube hole surface is quite irregular due to the drilling process. By rule of thumb, the peak to valley dimension of a 250 RMS surface finish is 4 times the RMS value, or 0.001 inch. If the tube and tubesheet are in intimate contact at the peaks of the surface finish an average tube to tubesheet radial gap of 0.0005 inch is established. The theory of flow between infinite parallel plates can be used to trend leakage characteristics for varying radial gaps. For a cylindrical condition the equation for leakage flow in volume is;

$$Q = \frac{\Pi \; D \; a^{3} \, \Delta P}{12 \; \mu \, L}$$

Where D = diameter of piston, a = crevice gap in radial direction, μ = absolute viscosity, L = axial length of crevice.

If a starting radial gap of 0.0005 inch is used, the average hydraulic expanded tube leak rate for a pressure differential of 1910 psi and 16.5 inch crevice length is 4.66×10^{-3} gpm, or slightly greater than the average of the room temperature 1910 psi leak rate data of [ ]^{a,c,e} gpm. In order to achieve the average leak rate for the 1920 psi data the effective crevice gap must be *reduced.* If the pressure of 1920 psi is applied to the tube ID, tube OD, and tube hole (as suggested by the H* crevice pressure test data), the calculated gap is *increased.* Thus the application of the crevice pressure in a pure sense, i.e., the crevice pressure results in hole dilation assuming the pressure is uniformly applied to the tube hole, [ ]^{a,c,e}. The contact points between the tube and tube hole result in an imperfect application of pressure resulting in [ ]^{a,c,e}.

This observation is even more pronounced for the W* tests. Using the room temperature, 2.2 inch crevice data with a starting crevice gap of 0.0005 inch, the calculated leak rate is 3.74×10^{-2} gpm while the observed average leak rate is [ ]a,c,e gpm (see Table 4-3). In order to achieve a leak rate of [ ]a,c,e gpm, the 0.0005 inch starting crevice gap must be reduced to [ ]a,c,e inch. If the crevice pressure is assumed to be zero for purposes of calculating the effect upon radial gap, the radial gap is closed only by about 0.0002 inch. Thus the W* condition can only suggest that the initial gap condition is much less than 0.0005 inch, implying that the resistance to flow is increased compared to hydraulically expanded tubes, and the pressure distribution through the crevice must then different from the hydraulically expanded tube tests. If the W* 1.1 inch length crevice test data is used, for a starting gap of 0.0005 inch, the calculated leak rate is $7.48\text{x}10^{-2}$ gpm while the average leak rate is [ ]a,c,e gpm. In order to achieve a leak rate of [ ]a,c,e gpm, the 0.0005 inch starting crevice gap must be reduced to [ ]a,c,e inch.

Thus, the leak rate trending equation from above, provided for trending purposes only, is a reasonable approximation of the hydraulically expanded tube leak tests and thus supports the crevice pressure distribution test results. Conversely, the trending equation from above does not approximate the W* test results, and therefore, supports the conclusion that the crevice pressure distribution is not [ ]a,c,e.

[

]a,c,e, thus producing a W* distance much less than currently provided by WCAP-14797, Rev 2. The application of secondary side steam pressure within the crevice included in the calculation of the W* distance in WCAP-14797, Rev 2, is then judged to be conservative. It could be theorized that the increased resistance to flow of the W* condition could produce a pressure distribution similar to that observed for the hydraulically expanded tube tests resulting in less flow for the same pressure differential. However, this could only be achieved if the contact area between the tube and hole were significantly increased which could only result in an [
]a,c,e.

The discovery of the crevice pressure condition for the hydraulically expanded tubes resulted in a change to the hydraulically expanded tube alternate repair criterion methodology. Prior to this point the pull out analysis used the same two-dimensional finite element model employed in the W* analysis. The mean pull out length for typical Model F SG operating conditions was approximately 7 to 8 inches. The application of the crevice pressure profile from the testing resulted in a significant change in the pull out length for this design of expansion joint. The pull out length was nearly double the original value. This conclusion prompted development of an improved, three-dimensional finite element model which is inherently more accurate than the old model. When the pull out length analysis was repeated using the deflection results from the new model, with the updated crevice pressure profile, the mean pull out length for the hydraulically expanded tube is less than the original pull out length. Thus, development of a three-dimensional model for the Model 51 SG, using a crevice pressure profile similar to what was obtained from the hydraulically expanded tube testing, would be expected to produce a W* pull out length that is less than the value currently developed in Reference 1.1. Table 4-3 presents a summary of the comparative leakage data for the W* and hydraulically expanded tube specimens using the leak rate trending equation for an assumed crevice gap of 0.0005 inch at room temperature and elevated temperature conditions. Table 4-3 also includes data for the elevated temperature cases where the initial assumed crevice gap of 0.0005 inch is reduced due to thermal and pressure expansion. The crevice pressure assumed for these cases is half of the primary-to-secondary pressure differential. The data of Table 4-3 show a common trend. The H* test data is closely approximated by the trending equation. The W* data is not supported by the trending equation which implies the assumptions are not applicable to the W* case.

4.6 SEQUOYAH UNIT 2 CONCLUSIONS

The Reference 1.1 determination of the cold leg W* length of 7.5 inches for Zone A and 5.5 inches for Zone B continue to apply to the cold leg tubes of SQN-2. The differences in length required for the two zones are based on a variance in the tubesheet bow between peripheral and center regions of the tubesheet. The differences between the SQN-2 specific and the generic calculation values is the result of the conservative assumptions associated with performing a generic calculation, e.g., extremely low secondary side pressure (which increases the applied load and the dilation of the tubesheet holes), additional pressure considered in the crevice, and the use of a lower bound residual expansion pressure. Nevertheless, the application of W* to the SQN-2 SG tubes per the Reference 1.1 guidance, and supplemented by this document, is considered to be justified. Despite these results, TVA will apply a cold leg W* distance of 10.5 inches for all cold leg tubes.

REFERENCES

4.1 TVA letter N10493, dated January 23, 2009.

4.2 Report Number WEST-13-402, Rev 1, "An Evaluation of the Statistical Variability in Coefficient of Thermal Expansion Properties of SA-508 and Alloy-600," Structural Integrity Associates, Inc., Centennial, CO., December 2008.

4.3 *Divider Plate Cracking in Steam Generators: Results of Phase I: Analysis of Primary Water Stress Corrosion Cracking and Mechanical Fatigue in the Alloy 600 Stub Runner to Divider Plate Weld Material.* EPRI, Palo Alto, CA: 2007. 1014982.

4.4 WCAP-16228-P, "PWSCC Susceptibility Assessment of the Alloy 600 and Alloy 82/182 Components in Wolf Creek," March 2004.

4.5 D'Annucci, F., "Inspection of the Steam Generator Partition Plate," Proceedings of ICAPP '05, Seoul, Korea, May 15-19, 2005, Paper 5711.

4.6 MRP-EDF-SGPP02, "Dampierre 1 / 2 NPP – Chemical, metallurgical and mechanical characterizations of the weld joining the partition stub, divider plate and channel head bowl"

4.7 MRP-EDF-SGPP04, "Chinon B NPP – Unit 4 – Characterization of indications on the SG #2 stub/partition plate welded surface"

4.8 *Divider Plate Cracking in Steam Generators: Results of Phase II: Evaluation of the Impact of a Cracked Divider Plate on LOCA and Non-LOCA Analyses.* EPRI, Palo Alto, CA: 2008. 1016552.

4.9 LTR-SGMP-09-8, "Effect of Variations in Coefficients of Thermal Expansion and Operating Conditions on W*," Westinghouse Electric Co, LLC, March 2009

Table 4-1 Comparison of W* for SQN2 SG Tubes Relative to Generic Information				
Item	**Analysis Term & Description**	**Sequoyah Unit 2**	**Generic W***	**Application of the Result**
1	ΔP, Applied Pressure (End cap)	Ps = 834 psig (849 psia)	P_G = 760 psia	SQN2 W* < Generic W*
2	P_T, Thermal Tightening	T_{cold} = 544°F	T_{hot} = 525°F	SQN2 W* < Generic W*
3	P_P, Pressure Tightening	Ps = 834 psig (849 psia)	P_G = 900 psia	SQN2 W* < Generic W*
4	P_D, Dilation Loosening	ΔP = 1403 psi	ΔP = 1490 psi	SQN2 W* < Generic W*
5	F, Three times normal end cap load	F_S = 2618 lb_f	F_G = 2781 lb_f	SQN2 W* < Generic W*

Table 4-2 Sensitivity of Calculated W* Distance to Variances in Tube/Tubesheet CTE					
Condition	**W* Mean Properties**	**W* Tube CTE -1 sigma**	**W* Tubesheet CTE +1 sigma**	**SRSS Combined W***	**WCAP W* Distance**
Normal Op – Hot Leg T-hot = 611F P-stm = 818 psig	3.90	4.54	4.45	4.74	7.0
Normal Op – Cold Leg T-cold = 544F P-stm = 818 psig	3.61	4.08	3.87	4.15	7.5
Faulted Case 2 - Cold Leg T = 460F P-stm = 0 psig	2.57	2.75	2.67	2.78	6.7

a,c,e

Table 4-3
Comparative Leak Rate Data: W* versus H*

Specimen Type	Joint Length (inch)	ΔP (psi)	Avg. Leak Rate (gpm)	Normalized Leak Rate (to H* Conditions)	Ratio of Normalized Leak Rates (W*/H*)
Room Temperature					
Elevated Temperature					
Comparison of Leak Rates using Trending Equation					
Specimen Type	Joint Length	ΔP	Calculated Leak Rate	Measured Leak Rate	Ratio Calculated to Measured LR
Room Temperature (crevice gap = 0.0005 inch)					
Elevated Temperature (crevice gap = 0.0005 inch)					
Elevated Temperature (crevice gap = 0.00029 inch for W*, 0.00033 inch for H*)					

5.0 STEAM LINE BREAK PRIMARY-TO-SECONDARY LEAKAGE DETERMINATION

This evaluation documents the primary water stress corrosion cracking (PWSCC) history of Sequoyah Unit 2 to establish that the most likely point of initiation is at the top of tubesheet, and that the PWSCC initiation potential below the top of tubesheet is significantly less than the top of tubesheet region. Evaluation of the SQN2 specific data indicates that the likelihood that a circumferentially separated tube exists below the current hot leg +Pt coil inspection distance of 8 inches below the top of tubesheet and proposed cold leg inspection distance of 10.5 inches below the top of tubesheet is exceptionally small. In addition, an analysis will be provided which suggests that PWSCC degradation is likely not present on the cold leg side at the top of tubesheet or within the expanded tube in tubesheet region.

This evaluation also establishes a conservative leakage allowance to be applied to the number of postulated circumferentially separated tubes in order to estimate steam line break condition leakage. This methodology is identical to the currently licensed methodology for the SQN2 hot legs and is identical to the methodology which was licensed for the Beaver Valley Power Station (BVPS) Unit 1 and Salem Unit 2. The leakage allowance is established by evaluation of existing drilled hole leakage data of Reference 1.1 for varying crevice length conditions between the top of the sample (analogous to top of tubesheet) and hole locations, and then relating the contact pressure between the tube and simulant collar to contact pressures within the actual SG tubes.

5.1 ESTIMATE OF THE NUMBER OF INDICATIONS IN SERVICE BELOW THE CURRENT HOT LEG TUBESHEET REGION INSPECTION DISTANCE OF 8 INCHES

Previous evaluations (Reference 5.1) of residual stress condition within expanded tube in tubesheet conditions have determined that residual stresses in the fully expanded region are compressive on the tube inside diameter (ID), thus, the likelihood of PWSCC initiation, with the exception of localized bulge or overexpansion locations, is negligible. Indications have been reported in this region, and are thus judged to be associated with localized bulge/overexpansion conditions which can produce a tensile residual stress at the edges of the geometric discontinuity. Standard SG manufacturing process is to drill the tubesheet holes from the primary face to the secondary face. Thus it is reasonable to assume that localized tube hole abnormalities that would lead to localized residual stress risers would be increased closer to the secondary face of the tubesheet. This supports the observed indication elevation distributions discussed later and is also supported by recent industry experience regarding PWSCC initiation in tube in tubesheet conditions in SGs utilizing hydraulic tube expansion with thermally treated Alloy 600 tubing.

The following discussion develops an indication distribution observed for the SQN-2 hot leg tubes and then estimates the postulated number of cold leg indications which could be present at the lower extreme of the cold leg inspection distance. It has previously been accepted that indications below the tubesheet neutral axis represent a negligible leakage potential due to the tightening of the tube-to-tubesheet joint as a result of tubesheet deflections.

5.1.1 Historical Trending of SQN-2 Hot Leg PWSCC

Figure 5-1 presents a Weibull plot of characteristic PWSCC trending for various types of expansion processes and Alloy 600 MA tubing. This figure includes data for Bugey-5 (kiss roll expansion), Farley 2 OSGs (full depth roll expansion), and SQN-2 (WEXTEX expansion). Clearly this plot shows that PWSCC initiation is least likely for WEXTEX expanded tubes.

PWSCC was first reported at SQN-2 at the EOC-4 (1990) inspection when four (4) axial PWSCC indications were reported. Circumferential PWSCC was first reported at the EOC-5 (1992) inspection in which two indications were reported along with 17 axial PWSCC indications at this outage. Circumferential PWSCC was not reported again until the EOC-8 (1997) inspection when 3 indications were reported. Axial PWSCC indications were reported at the EOC-6, EOC-7 and EOC-8 inspections. The 1996 (EOC7) inspection was the first application of +Pt inspection technology for the tubesheet region.

Through the EOC-10 (2000) outage the +Pt examination depth below the hot leg top of tubesheet (TTS) was 2 inches, i.e., the tube length between 2 and 8 inches below TTS was not previously inspected using a +Pt coil. A total of 82 axial PWSCC indications (80 tubes) and 15 circumferential PWSCC indications (15 tubes) were reported from EOC-4 through EOC-10.

The +Pt inspection distance was extended to 5.5 inches below the top of tubesheet for the EOC-11 outage. Of the total 26 indications reported at the EOC-11 inspection, twelve (12) indications (11 axial, 1 circumferential) on nine (9) tubes were reported within 2 inches of TTS. If the indication initiation distribution were uniform over the entire tube-in-tubesheet distance then approximately one hundred sixty-nine (169) indications would have been expected to be observed at the EOC-11 inspection in the distance between 2 and 5.5 inches below TTS (97 indications * 3.5/2). However, only 14 indications (9 axial, 5 circumferential) on 14 affected tubes were reported in this elevation range (2 to 5.5 inches below TTS) strongly implying that the distribution of indications is not uniform within the tubesheet and that the density of indications is skewed with the highest density near the top of tubesheet.

For the EOC-12 inspection, the +Pt inspection distance was increased to 8 inches below the TTS. A total of 15 PWSCC indications were reported; 7 were reported within 1 inch of the top of tubesheet, none were reported in the elevation range from 2 to 5.5 inches below the top of tubesheet, and 8 were reported at > 5.5 inches below TTS. These 8 indications located greater than 5.5 inches below TTS had never been previously inspected using a +Pt coil. Through the EOC-12 inspection 116 indications on 111 tubes had been reported within 2 inches of the top of tubesheet. For the 5.5 to 8 inch distance below the top of tubesheet, at least 111 tubes would have been expected to be affected if the initiation potential were equal over the entire tube length. As only 8 indications on 6 tubes were reported in this range the argument that initiation potential is greatest at the top of tubesheet is even more strongly supported.

For the EOC-13 to EOC-15 inspections a total of only 17 hot leg indications on 15 hot leg tubes were reported. Eleven (11) of these 17 were located within 2 inches of the top of tubesheet, 4 were located between 2 and 5.5 inches below the top of tubesheet, and 2 were located at greater than 8 inches below the top of tubesheet. Zinc injection was initiated during Cycle 12 and a noticed reduction in indication counts is observed for EOC-13, EOC-14, and EOC-15. This impact upon PWSCC initiation will be applicable to all regions of the tubes.

Figure 5-2 presents a cumulative distribution plot of elevations of all PWSCC indications reported at SQN2 and other plants with Series 51 SGs and WEXTEX expansion. Since elevation information is not available for the EOC-7 and earlier outages, the total number of indications reported from these outages were assigned to elevation bins based on the elevation distribution for the EOC-8 and later outages. This plot clearly shows that the PWSCC initiation potential is significantly greater for the top of tubesheet region than at deeper elevations. Recall that for the EOC-10 and all earlier outages, the +Pt inspection distance below TTS was 2 inches while for the EOC-11 and EOC-12 outages the +Pt inspection distances below TTS were 5.5 and 8 inches, respectively. Figure 5-2 shows a greatly reduced initiation potential for indications at deeper elevations below TTS. Figure 5-2 also presents cumulative distribution data of PWSCC as a function of elevation for the EOC-11 and EOC-12 outages only. As these outages involved inspection of lengths never before inspected the cumulative probability plot as a function of elevation would be significantly different from the plot for all outages if the initiation potential were equal over the entire tube length. However, the cumulative probability plot is quite similar to that for all outages.

5.1.2 Simplistic Indication Distribution Estimate

For the EOC-11 through EOC-15 inspections, none of the affected tubes included indications in more than one of the inspection ranges (e.g., TTS to -2 inches, -2 to -5.5 inches, and below -5.5 inches). Therefore, it is a reasonable assumption that none (or a very small percentage) of the tubes plugged at earlier outages included indications below the applied inspection distances. This permits a simplistic evaluation methodology for estimating indication counts below previously inspected regions. As the total number of indications and tubes are similar, the analysis will be based on indication counts. The total number of indications reported to date is 161. Of these 161, 144 or 89% are located within 4 inches of the top of tubesheet, 11, or 7% are located between 4 and 8 inches below the top of tubesheet, and 6, or 4% are located greater than 8 inches below the top of tubesheet. Reference 1.2 arbitrarily assumed that 25% (41 indications) of the total indication count, including future indications, would be found at greater than 8 inches below the top of tubesheet primarily due to the limited inspection experience for depths below 5.5 inches at the time (2004) that Reference 1.2 was prepared. Such an arbitrary assessment is without basis considering the inspection results for the last three inspections. If it is assumed that the susceptibility within the 4 to 8 inch below TTS range is representative of the 8 to 12 inch below TTS range, then only 11 indications would be expected in this range.

5.1.3 Regression Fit to Indication Elevation Data

The flaw counts within 1 inch of the top of tubesheet were excluded from a regression analysis which estimates flaw counts as a function of elevation over the entire tubesheet thickness. The actual elevation reports were used, opposed to binned data as discussed above. The best fit (i.e., largest correlation coefficient) to the data was obtained for a log-log analysis. Figure 5-3 presents the plot of this analysis, with the results converted back to a normal scale for readability. A 95%

prediction bound was developed from this data and is also shown on Figure 5-3. From the 95% prediction bound, 4 indications are anticipated in the 8 to 9 inch below TTS bin, 3 to 4 indications in the 9 to 10 inch below TTS bin, 3 to 4 indications in the 10 to 11 inch below TTS bin, and 3 indications in the 11 to 12 inch below TTS bin. Thus, a total of 15 indications are assumed present in the elevation range from 8.01 to 12 inches below TTS. This result is conservative compared to the simplistic evaluation discussed above. The binned indication count data for the EOC-11 and EOC-12 outages shows the largest number of indications in any 1 inch bin below the expansion transition was only 4. Therefore, there is no basis to assume that large numbers of indications are present below the currently applied inspection depth.

5.1.4 Conclusions Regarding Hot Leg Indication Counts

Through the EOC-15 outage, 161 total hot leg indications have been reported, only 36, or 22%, of which were circumferentially, obliquely, or volumetrically oriented. The leakage estimation conservatively assumes that *all* indications below the applied inspection distance are circumferentially oriented.

A regression analysis using all of the data excluding the expansion transition suggests that approximately 15 indications are present in the 8.01 to 12 inches below TTS elevation range. For the cycles when zinc injection has been applied for the full cycle (Cycles 13, 14, and 15) only 17 PWSCC indications have been reported. The maximum of 11 indications over these inspections occurred at EOC-13, which was the first full cycle after zinc injection began. To account for future indication initiation, and to provide an extra conservatism, a total of 25 indications will be assumed to be present in the elevation range of 8.01 to 12 inches below TTS for estimating the number of cold leg indications that might be present. A very small number of these 25 postulated indications between 8 and 12 inches below TTS would be expected to have all of the following characteristics:

1. Be circumferentially oriented
2. Represent a 100% through-wall (TW) condition, and
3. Extend for 360° (circumferential cracks).

At the EOC-12 inspection in 2003, which was the first inspection to 8 inches below TTS, four circumferential indications were reported; three were located at the WEXTEX expansion transition and one was located at 9.8 inches below TTS. As the length of tubing from 5.5 to 8 inches below TTS had never been inspected using a +Pt coil, it would be expected that a modest number of large voltage indications would be observed in this range. None of these four were representative of a 100% TW condition based on the +Pt amplitude and the longest circumferential flaw arc length was only 46°. Eleven axial PWSCC indications were reported, of which seven were located at > 5.5 inches below TTS and were not previously inspected. Only one of the EOC-12 axial indications represented a 100% TW degradation potential based on flaw amplitude. Therefore, for the 25 postulated indications between 8 and 12 inches below TTS, six (22%) of 25 would be expected to be circumferentially oriented, and the number of indications with 100%TW penetration over 360° is zero. The 36 circumferentially oriented indications reported to date were located between the expansion transition and 9.8 inches below TTS; only four were located at > 4 inches below TTS. The longest circumferential PWSCC arc length reported for all outages was 97° at the EOC-11 outage.

Figure 5-4 presents a tubesheet map plot of all Unit 2 PWSCC indications reported at EOC-8 and later. A total of 25 of the 97 indications in this population are reported to be in the outboard region, defined as Zone A, which is the zone with the lesser amount of tubesheet deflection during operating or faulted conditions.

The above data were developed using the nominal inspection distance below TTS of 2, 5.5, or 8 inches, based on the outage chronology. In actuality, the inspection distance applied to each tube exceeds the specified value. This is purposely done during the data collection process to ensure that the appropriate distance is examined. This is shown by the deepest reported indication which resides at about 11 inches below TTS.

Previous evaluation of the residual stress distribution in hydraulically expanded tube-to-tubesheet joints indicates that the residual stresses below the expansion transition are likely compressive in nature. Therefore, PWSCC initiation is likely associated with a localized geometry discontinuity resultant from the tube drilling process. As all tubesheet holes were drilled from the primary face, the frequency of tube hole abnormalities would be expected to be increased as the secondary side face of the tubesheet is approached. The data of Figure 5-2 supports this argument. Furthermore, the circumferential extent of these abnormalities would be expected to be limited. The inspection data that shows the largest circumferential arc extent is 90° for indications >1 inch below TTS also supports this assumption.

5.2 LEAKAGE POTENTIAL EVALUATION OF POSTULATED CIRCUMFERENTIAL DEGRADATION BELOW W*

During W* reviews circa 2004/2005, the NRC Staff had previously questioned the validity of the original assumption presented by WCAP-14797, Rev. 2, that postulated circumferential degradation below W* would not produce leakage at SLB conditions. An outcome of this was inclusion of an exceptionally conservative leakage allowance for degradation below the W* inspection distance. This leakage allowance ignores the fact that the leakage data suggests a correlation between contact pressure and leak rate and that below the neutral axis in particular, the contact pressures become exceptionally large. The following is a reiteration of the previously licensed leakage methodology applied at the SQN-2 (Reference 1.2) and BVPS-1 hot legs. This evaluation continues to apply to the hot legs and also applies to the cold legs.

This section establishes a basis supporting the argument that meaningful leakage would not result from degradation below the W* elevation. The accuracy of this statement can also be qualitatively verified by examining operating plant history. SG leakage events have been attributed to ODSCC in the freespan and at TSP intersections, PWSCC at U-bends, at tack roll transitions of non-expanded tubes, and due to loose parts/foreign objects. Therefore, as no operating experience has been associated with postulated circumferential degradation below W*, it is reasonable to assume that the potential for such indications is unlikely, or that the inherent leakage resistance of at least 7 inches of sound WEXTEX expansion (based on a nominal 8 inch below TTS inspection distance when the expansion transition distance is ignored) at TTS is sufficient to preclude reportable leakage (i.e., < 2 gpd or < $1.4 \cdot 10^{-4}$ gpm).

Two sets of leakage data support the W* criteria. The first set of data was prepared by tack rolling a 7/8 inches OD by 0.050 inch wall thickness Alloy 600 tube into a carbon steel collar. The tube was then seal welded to the collar and then WEXTEX expanded. Ten (10) 0.125 inch diameter holes were drilled through the collar and tube at elevations referenced from the top of the test collar. The second set of leakage data examined the impact of contact pressure upon crack opening potential for axial flaws. This data may not be directly applicable to postulated circumferential degradation but it does show that at about 2500 psi contact pressure that leak rates are essentially zero, i.e., $< 1.33 \cdot 10^{-5}$ gpm. These tests located the upper crack tip immediately below a channel machined in the tubesheet collar to eliminate any potential for flow restriction. The prevention of leakage at this contact pressure is expected to be independent of flaw orientation as contact pressure exceeds the primary-to-secondary pressure differential.

For the first set of leakage data, if it is assumed that the entire circumference of the drilled holes contributes to the leakage flow, the effective leakage flow length was 3.93 inches which is greater than the leakage flow length of a postulated circumferentially separated tube of 2.79 inches based on a tubesheet hole ID of 0.890 inch. The first set of holes was located at 3 inches from the top of the test collar thus resulting in a tube to collar contact length of < 3 inch due to the transition geometry. The through holes in the carbon steel collar were drilled to a diameter slightly larger than 0.125 inch to permit staking of the tube holes. This staking operation inwardly deformed the tube at the tube/collar interface, in effect pulling the tube from the collar at the hole to ensure that the drilling operation did not affect the leak path. For this set of tests, the leak rate at 600°F was essentially 0 at SLB pressure differential. For these samples tested at 600°F and a pressure differential of 1620 psi, leak rates were essentially identical to the 2650 SLB tests suggesting that the increased driving pressure was balanced by the increased contact pressure due to pressure expansion. The observation of leakage at normal operating conditions in the leakage samples is not consistent with operating plant experience, either the samples yield conservative leakage estimates or such degradation is not present in operating units. A choked flow condition may have also been present which implies that increased expansion distance between the indications and the top of the tubesheet would further reduce leak rate by adding additional resistance to flow. After completion of the 3 inch tests, a new set of holes was drilled at 2 inches from the top of the test collar. Leak rates were elevated above the 3 inch test levels. This process was repeated again locating the holes at 1.25 inches below the top of the collar and leak rates were again elevated above the previous test levels. The tube holes were not plugged after completion of testing at the 3 inches and 2 inches nominal crevice tests. Thus, the 1.25 inches and 2 inches nominal tests included leakage effects of the holes below these elevations.[3] In effect, the 1.25, 2, and 3 inches nominal crevice tests simulated tubes with circumferential separations at 7.7, 9.5, and 10.3 inches below TTS respectively when based on the contact pressures presented in Figure 5-5, which were conservatively taken from the values developed for pull out load analyses as listed in Table 4.3-9 of WCAP-14797, Rev 2. The use of the contact pressures developed for leak rate analysis and presented in Table 4.3-11 of WCAP-14797, Rev 2 would yield equivalent depths of about 1 inch less than those listed above. Using the above values result in an increase in the margin relative to contact pressure of about 500 psi. All of these tests were conducted at a temperature of 600°F. The inherent WEXTEX expansion contact pressure is not included in the values of Figure 5-5. It should also be noted that

[3] This would be expected to be small because of the lack of a pressure drop between the holes.

the large flow area provided by the drilled hole configuration extremely bounds any associated effect of crack opening upon leakage for axially oriented degradation.

Prior to elevated temperature testing, room temperature testing was conducted at 1620 psid for each of the crevice depth conditions. For the room temperature, 3 inch tests at 1620 psid, the average leak rate was ~100 times the 600°F average leak rate. Figure 5-6 presents the 600°F drilled hole leak rate test data as a function of crevice depth for 2650 psid. Figure 5-7 presents the 600°F drilled hole leak rate test data as a function of crevice depth for the 2650 psid and 1620 psid test conditions. For the 3 inch nominal crevice tests at 2650 psid, the actual crevice depths were 2.37 inches, 2.29 inches, 2.37 inches, and 2.1 inches, for an average crevice depth of 2.28 inches. For the 2 inch nominal crevice tests, the average crevice length was 1.28 inches, and for the 1.25 inches nominal crevice tests, the average crevice length was 0.61 inches.

For the 3 inch tests at 600°F, 2 of the 4 samples had no leakage at 1620 or 2650 psid. The leak rates of the other two 2650 psid samples were $1.33 \cdot 10^{-6}$ gpm and $1.33 \cdot 10^{-5}$ gpm. For these tests, radial contact pressure due to thermal expansion, pressure expansion, and WEXTEX expansion are inherent. There was no allowance for tubesheet hole dilation. Thus, these tests can be seen as a representation of the point where tubesheet hole dilation effects are neutral, i.e., at the neutral axis, or between 11 and 12 inches below the TTS.

The above developed upper 90% prediction leak rates of $4.5 \cdot 10^{-3}$ gpm per tube for indications between 8 and 12 inches below TTS and $8.7 \cdot 10^{-5}$ gpm per tube for indications >12 inches below TTS are developed using data for those specimens that leaked. Note that 2 specimens with 3 inch nominal crevice lengths did not leak. If a leak rate of $7 \cdot 10^{-6}$ gpm, which is the average leak rate of the 3 inch nominal specimens that leaked is applied to the zero leakage specimens the upper 90% prediction is reduced by a factor of 1.3 (see Figure 5-6). If a leak rate of $1.33 \cdot 10^{-6}$ gpm, which is the lowest leak rate of the 3 inch nominal crevice specimens is applied to the zero leakage specimens the upper 90% prediction is reduced by a factor of 2.7 (see Figure 5-6). Figure 5-6 also shows the dependence of the leak rate on crevice depth, e.g., any postulated leakage from a separated tube at 18 inches below TTS (which would include increasingly greater contact pressure with increasing depth below TTS) would be much lower than the applied value which is based on a depth of 12 inches below TTS.

Figure 5-5 presents a plot of contact pressure as a function of distance below TTS for 4200 seconds into the SLB event, excluding WEXTEX contact pressure. At this point, the primary and secondary side temperatures are assumed to be constant, and tubesheet bow effects are maximized. The contact pressures of the drilled hole leak specimens were calculated neglecting the residual WEXTEX contact pressure. The contact pressures in the drilled hole specimens are similar to the predicted contact pressures in the tube for depths of about 7.7 to 10.3 inches below TTS, excluding WEXTEX expansion contact pressures. Calculation of the SG tube contact pressures and leakage specimens on Figure 5-5 assumes no pressure within the crevice. This results in a conservative evaluation when the contact pressures of the leakage specimens are being compared against the contact pressures of the SG tubes in order to associate leakage characteristics of a particular leakage test set with an elevation on the tube.

Reference 1.1 calculates the total positive radial contact pressure as a function of depth below the top of tubesheet due to thermal expansion, pressure expansion, and WEXTEX expansion. The reduction in contact pressure due to tubesheet bow is included to develop resultant radial contact pressure as a function of depth below the top of tubesheet. If the Zone B data with WEXTEX contact pressure is conservatively applied to the entire tubesheet, at approximately 9.1 inches below TTS, the resultant radial contact pressure is 2500 psi.

Figure 5-5 shows that the drilled hole test contact pressures are higher for the actual crevice lengths tested compared to the resultant plot of contact pressure for a tube at the same crevice depth condition. The 1.25 inches nominal crevice tests involve a contact pressure consistent with the Zone B tube at approximately 7.7 inches below TTS and the 3 inch nominal crevice tests involve a contact pressure consistent with the Zone B tube at approximately 10.3 inches below TTS. The rate of change of contact pressure as function of distance below TTS is more rapid for the drilled hole specimens than for the actual tube. For the 1.25 inch nominal crevice test case, an actual crevice length of ~0.6 inch with positive contact pressure was provided. The corresponding tube would have a crevice of ~5.3 inches with positive resultant contact pressure for ~3.5 inches above a postulated separation. Thus, it could be argued that the drilled hole specimen data is conservative compared to the actual tube in the range of 7.7 to 10.3 inches below TTS due to the more rapid change in contact pressures as a function of distance below TTS and shorter crevice length with positive contact pressure. However, since the contact pressure reduction due to hole dilation was not included, a conservative estimate of potential leak rate for a postulated circumferentially separated tube below the W* inspection distance of 8 inches below TTS would be to use the predicted leak rates. At this crevice depth (equivalent to leakage specimens with actual crevice depth of 0.61 inch), the predicted leak rate is $1.9 \cdot 10^{-3}$ gpm using the mean (arithmetic average) regression of the leak rate as a function of actual crevice depth and $4.5 \cdot 10^{-3}$ gpm at the upper 90% prediction bound, see Figure 5-5. Thus, the SLB condition conservative leak rate applied to a circumferentially separated tube between 8.0 and 12 inches below TTS is $4.5 \cdot 10^{-3}$ gpm. For a postulated circumferentially separated tube at > 12 inches below TTS, substantial contact pressure and crevice lengths would exist above this location, resulting in a no leakage condition. However, a conservative leakage allowance will be included.

It is noted that the leak rate data are independent of the test pressure for the lengths tested since fitting separate regression lines yields similar slopes and intercepts. Statistical comparisons were made of the results of such analyses and it was found that there were no statistically meaningful differences. Thus, the attendant increase in contact pressure compensated for the increase in pressure difference by reducing the area available for the leakage flow, or the flow in the test specimen crevices was at choke conditions. Regardless, the conclusion is that all of the leak rate data, i.e., those for 1620, 2000 and 2650 psid, could have been included on the same plot. Performance of this analysis results in a similar regression line that predicts slightly lower median flow rates. The other consequence of including all of the data is a reduction in the standard error of the regression and a reduction in the 90th percentile prediction bound, about a factor of two or slightly greater over the range of interest. Thus, the above calculation is based on a conservative segregation of the data. In addition, finally, additional calculations were performed to obtain linear regression coefficients for the logarithm of the leak rate as a function of the crevice length and the calculated contact pressure. The regression results were then used to estimate the 90th percentile prediction bound relative to the predictions based on the regression on crevice length alone. The results indicated that neglecting the contact pressure leads to over predictions on the order of 4 to 20 relative to that from using the combined data set. In conclusion, the bounding calculation results reported could be about an order of magnitude greater than would be obtained from a refinement of the analysis.

As no 100% TW, 360° circumferentially separated tubes are anticipated to be present between 8 and 12 inches below TTS, application of the W* alternate repair criteria could be such as to not involve leakage from postulated indications below W*. No leakage would be expected due to the substantial contact pressure at greater than 12 inches below the top of tubesheet. However, for practical purposes an estimate can be made and is discussed in developing a conservative estimate of the potential leakage as follows:

1) If it is assumed that all 41 postulated hot leg indications between 8 and 12 inches below the TTS are circumferentially oriented and the tubes are severed, the leakage associated with these indications is 0.18 gpm using the 90th percentile leak rate corresponding to a test specimen crevice length of 0.61 inch which has a contact pressure similar to that in the SG at a depth of ~8 inches, and would be dispersed over 4 SGs.

2) A conservative estimate of leakage for indications at greater than 12 inches below TTS can be accomplished by applying the upper 90th percentile prediction leak rate at 2650 psid for the 3 inch nominal crevice data of $8.7 \cdot 10^{-5}$ gpm. The contact pressure for the 3 inch nominal crevice samples is approximately equal to a Zone B at 10 inches below the TTS. At 12 inches below the top of tubesheet, the expected Zone B contact pressure at 4200 seconds into the SLB event is approximately 2900 psi, about 600 psi greater than for the average of 2273 psi for the 3 inch nominal crevice length leakage specimens.

   If all remaining active tubes in the least plugged SG are assumed to contain a circumferential separation at 12 inches below TTS, the SLB leakage contribution would be approximately 0.26 gpm (3000 tubes times $8.7 \cdot 10^{-5}$ gpm per tube). Note that 2 of the 4 samples had no leakage at 2650 psid and the constrained crack leak test data suggest that no leakage could be expected, regardless of the indication orientation at a contact pressure of greater than 2500 psi.

   Zone A contact pressures as a function of depth below the top of the tubesheet are higher than for Zone B to a depth of about 11 inches. The increase in contact pressure above that depth can have a significant effect on the leak rate, however, this has been conservatively neglected in the leak rate analysis. Zone A tubes retain positive resultant contact pressure for almost the entire crevice length. The added length with positive contact pressure is expected to provide a substantially increased resistance to leakage during a postulated event. It should also be noted that the assumption that all tubes contain a circumferential separation at > 12 inches below TTS is an extreme conservatism.

Combining the upper 90% prediction leak rate with the assumption that all tubes are separated is even more conservative, and may be so conservative that the predicted value is unrealistic. For a large number of samples, i.e., assuming all tubes are separated, any postulated SLB condition leakage would be expected to migrate to the mean leak rate. The mean, i.e., arithmetic average, leak rate regression for the 3 inch nominal crevice length specimens is on the order of $1.6 \cdot 10^{-5}$ gpm per tube, and for the conservative assumption of all tubes separated, the expected leak rate would then be about 20% of the value of 0.26 gpm calculated above.

Predicted leak rate as a function of contact pressure was also considered, however it was determined that the leak rate prediction is best accomplished using the specimen crevice depth. This determination was based on a comparison of the statistical goodness-of-fit between the two sets of data. At equal probability levels, the estimation of leakage using crevice depth provides for a conservative total leakage prediction compared to the estimation of leakage using contact pressure.

Additional conservatism is present in the above described leakage prediction since all indications below the EOC-13 planned inspection depth of 8 inches below TTS are assumed to be circumferentially separated. As stated above, only 22% of the total historical indication count is circumferentially oriented. Leakage estimation from axial PWSCC is substantially less than the model used for circumferentially oriented PWSCC.

5.3 CONFIRMATORY LEAK RATE EVALUATION

In order to partially quantify the conservatism associated with the first order linear regression analysis approach involving only the crevice length, a subsequent analysis was performed which included the contact pressure as a second variable. The analysis also considered all of the data in establishing the regression line. The results of the analysis are presented on Figure 5-8. The 90th percentile leak rate for a crevice depth of 0.61 inch is $5.24 \cdot 10^{-4}$, corresponding to the value of $2.0 \cdot 10^{-3}$ from the single variable analysis, a difference of a factor of 4. Compared to the applied leakage allowance of $4.5 \cdot 10^{-3}$, a factor of 8.6 is established. Likewise, the bounding leak rate using both crevice length and contact pressure for a length of 2.28 inches was calculated to be $1.33 \cdot 10^{-5}$, a factor of 2.9 less than the corresponding value from the single variable analysis and a factor of 6.5 less than the applied leak rate value.

Application of these results to the previous analyses leads to the expectation that the 0.18 gpm total leak rate from 41 indications in the range of 8 to 12 inches below the TTS would be reduced to 0.021 gpm by increasing the complexity of the analysis. Similarly, the 0.26 gpm leak rate for 3,000 postulated separated tubes at a depth of 12 inches would be reduced to 0.04 gpm, with the total expected leak rate being about 0.055 gpm instead of the considered 0.44 gpm. The calculated median leak rate per tube used with the assumption that all of the tubes in the SG are severed is reduced from $4 \cdot 10^{-6}$ to $4.3 \cdot 10^{-7}$ gpm per tube. Reference 5.3, prepared by Argonne Laboratory, presents an assessment of crevice leakage which concludes that loss coefficient, and therefore leak rate, are a function of contact pressure. Thus, the applied leakage allowances are conservative by a factor of at least 6.5.

The expectation of 41 indications in the 8 to 12 inch below TTS range was based on the hot leg indication data as of the EOC-12 outage. As only one inspection was performed with an inspection depth of 8 inches below TTS, the number of future indications in this range was not known. The previous evaluation assumed that the number of indications in the 8 to 12 inch depth below TTS was 25% of the expected EOC-13 total. As four inspections to a minimum depth of 8 inches below

TTS have been performed, the recommended approach is to apply the regression of depth with additional conservatism to establish the value of 25 indications within the 8 to 12 inch below TTS range for estimation of cold leg indication count.

The applied W* leakage methodology is considered to be exceptionally conservative. If the leakage estimation methodology developed under the H* alternate repair criterion were applied, the faulted condition leakage would be bounded by a factor of 2 compared to normal operating conditions. If the H* leakage methodology were applied, and the measured normal operating condition leakage were 2 gpd, the faulted condition leakage would be bounded by 4 gpd, or 0.00278 gpm. Thus it can be concluded that the W* leakage methodology is exceptionally conservative.

5.4 CONCLUSIONS REGARDING LEAKAGE TESTING

The WEXTEX drilled hole leakage testing indicates the following characteristics for a WEXTEX expanded tube with a postulated circumferential separation below the W* inspection distance.

1. Comparison of the room temperature and elevated temperature tests indicates that elevated temperature leak rates were approximately 100 times less than room temperature leak rates.
2. Comparison of the elevated temperature test data for 1620 and 2650 psi pressure differential shows the leak rates are essentially constant for both pressure differential conditions suggesting that pressure expansion has a limited effect on leak rates.
3. Based on the observations of Items 1 and 2, contact pressure is seen as the most significant factor for restricting leak rate.
4. For the 1.25 inch nominal crevice test case, the contact pressure is approximately equal to the contact pressure of an expanded tube at 7.7 inch below TTS while for the 3 inch nominal crevice test case, the contact pressure is approximately equal to the contact pressure of an expanded tubes at 10.3 inches below TTS. The contact pressure reduction in the test samples was more rapid (per unit length) than in the actual tube. Contact pressures in the leakage specimens did not account for pressure within the tube-to-tubesheet crevice, and results in a conservative estimate of contact pressure.
5. The accumulation of the leakage effects of the holes at 2 and 3 inch below TTS can be seen as a representation of the postulated case where the tube is separated at 7.7, 9.5, and 10.3 inch below TTS. The leak rate determined for the 1.25 inches nominal crevice tests is a conservative estimate of leakage for a tube with a postulated circumferential separation below the W* inspection distance.
6. Evaluation of the reported flaw elevations for SQN2 shows that indications were reported as deep as 9.8 inches below TTS. Therefore, a number of tubes were inspected to depths exceeding the nominal inspection depth for EOC-12 of 8 inches below TTS. Therefore, the likelihood of any postulated circumferentially separated tube at or below 8 inches below TTS is exceptionally small.
7. Zone B tubes were used for estimation of SLB condition leak rates. The Zone A tubes retain positive resultant contact pressure over the entire crevice length, and this increased length is expected to represent a significant decrease in SLB condition leak rates compared to Zone B.

5.5 SQN-2 COLD LEG INSPECTION HISTORY

The cold legs of all SGs were sampled with +Pt at a 20% level at the EOC-13 (2005) outage. The inspection extent was +2 to -8 inches. No indications were reported. Accumulated effective full power years (EFPYs) at EOC-13 was 16. For a 20% sampling with no indications reported, a beta distribution can be used to estimate the number of potential indications present at various percentiles. At the mean, on a per SG basis, 4 potential indications could be present, while at the 80th percentile, 7 indications could be present, and at the 95th percentile, 11 indications could be present. For the various numbers of postulated indications the likelihood of detecting at least one indication can be established. If it is assumed that 11 indications were present the probability that at least one indication was sampled is 89%, or a very high likelihood that at least one indication was sampled. For 7 assumed indications the probability that at least one indication was sampled is 75%, or still a very high likelihood that at least one indication was sampled. For 4 assumed indications the probability that at least one indication was sampled is 55%, which then represents a reasonable likelihood that 4 or less indications per SG could be present. But when the combined influence of sampling in all SGs are considered, the overall probability that at least one indication amongst the four SGs were sampled is the product of all probabilities, or 91%, and it can therefore be concluded that no SCC was present at the cold leg TTS at 16 EFPY.

An SCC affected level of 0.1% is applied for comparison of degradation mechanisms. An affected level of 0.1% represents 3 tubes per SG. This level is selected as the "first reporting" of a particular SCC mechanism may be erroneous, particularly if the mechanism was reported using other than the current state-of-the-art inspection probe, or, if the next reporting after the first reporting appears several outages later. The 0.1% PWSCC affected level for the hot leg was achieved at the EOC-5 outage (5.37 EFPY). If the 0.1% affected level for the cold leg is assumed to have occurred at EOC-14 (17.6 EFPY), or one cycle after the applied cold leg sampling, it can be established that the minimum empirical improvement factor is not less than 3.28 (17.6/5.37).

5.6 OTHER PLANT COLD LEG INSPECTION HISTORIES

This section discusses inspection histories from other plants with A600 MA tubing and extensive histories of SCC on the hot legs, plus extensive cold leg RPC inspection histories.

5.6.1 Farley Unit 1

The Farley Unit 1 original SGs were identical to the SQN-2 SGs. The EPRI Steam Generator Degradation Database (SGDD) and Westinghouse reports were used to acquire tubesheet region degradation data for Farley Unit 1. The first reporting of PWSCC is at the EOC10 outage in 1991 (9.91 EFPY). A total of 75 indications are reported. As this is about the time that RPC probes were gaining wide acceptance, it was judged that a portion of these 75 were likely present in prior outages. PWSCC trending from more recent inspections of other SGs which involved a high percentage of tubes inspected and more recent probe designs leads to the conclusion that the number of PWSCC indications observed at the first reporting is typically small, followed by an increasing trend to a fairly constant value. For all subsequent outages, the PWSCC count averaged 33 per outage and was never more than 52, which occurred at 15.15 EFPY. So the first reporting (and 0.1% affected level) is taken as EOC8 with an accumulated EFPY of 7.33. For evaluation purposes, 15 indications are assumed for EOC8, 25 indications are assumed for EOC9, and 35 indications are assumed for EOC10.

At the 1R13 outage (13.77 EFPY), a 20% RPC sample of the cold leg top of tubesheet was performed in each SG. At the 1R14 outage (15.15 EFPY) an initial 20% cold leg RPC sample was performed in each SG. An additional 800 indications were inspected in SGA due to detection of cold leg pitting. At the 1R15 outage (16.38 EFPY), the cold leg of SGB was inspected at 100% with RPC while SGA and SGC were inspected at the 20% level. No SCC indications were detected on the cold legs in any of these inspections. As the SGB cold leg was inspected at 100% at 1R15, no indications are assumed present based on statistical evaluation of results. For SGA and SGC, a minimum of 60% of the cold tubes were inspected from 1R13 through 1R15 with no indications reported. At the 80% probability level, 1 indication in SGA and 1 indication in SGC could be present (i.e., 20% probability of not sampling). The SGB cold leg inspection results show SCC was not present, thus the 0.1% affected level was not achieved through 16.38 EFPY.

5.6.2 Diablo Canyon (DCPP)

Both the Diablo Canyon Unit 1 and Diablo Canyon Unit 2 original SGs were identical to the SQN-2 SGs. The EPRI SGDD was used to acquire tubesheet region degradation data for the DCPP units. Both Diablo Canyon units had the W* criterion applied to both hot and cold legs. PWSCC at the top of tubesheet and in the tubesheet region was first reported at 1R6 at Unit 1 (7.14 EFPY) and at 2R5 at Unit 2 (5.74 EFPY). The DCPP T-hot was approximately 603°F. Through the 2005 Unit 1 inspection (17.2EFPY), the tubesheet region PWSCC totals were bounded by the SQN-2 total. The predominant mode of PWSCC was axially oriented. Through the 2004 Unit 2 inspection (16.09 EFPY), the tubesheet region PWSCC totals bounded the SQN-2 total. The predominant mode of PWSCC was axially oriented. At the Unit 2, 2003 inspection (14.57 EFPY), the cold leg of SG24 (Unit 2, steam generator 4) was inspected at 100%, while SG21, SG22, and SG23 were inspected at 20%, to a depth of 8.5 inches below the cold leg top of tubesheet. No SCC was reported at the cold leg. If the first observation of PWSCC on the cold legs is assumed for the 2005 inspection (16.09 EFPY), an improvement factor of no less than 16.09/5.74 = 2.80 could be established however, it must be noted that cold leg PWSCC was not reported at the 2003 inspection.

5.6.3 Farley Unit 2

The Farley Unit 2 original SGs were similar to the SQN-2 SGs with the exception that the tubes were full depth roll expanded. The 0.1% PWSCC affected level is observed at 3.99 EFPY and at the final inspection (15.2 EFPY) over 1300 hot leg tubes were affected with PWSCC. At 12.57 EFPY a 20% sampling of the cold legs of all SGs was performed; no indications were reported. At 13.9 EFPY an initial sample of 20% of the cold legs was applied in all SGs. Two SGs had no SCC reports; one SG had one axial PWSCC report. The inspection scope was expanded to 100% in the affected SG; four additional indications were reported thus the 0.1% affected level was achieved in one SG out of three. At 15 EFPY, the cold leg scope was 100% in the previously affected SG and 20% in the other two. One indication was reported in the previously affected SG; no indications were reported in the other two SGs. Thus for roll expanded tubing a minimum empirical hot leg to cold leg improvement factor of 3.5 (13.9/3.99) can be established, however it should be noted that this improvement factor is established only for the SG with indications. Based on the Weibull plot of Figure 5-1 roll expanded tubing clearly exhibits a more susceptible condition compared to WEXTEX expanded tubing and application of the 3.5 factor to SQN-2 is conservative.

5.6.4 Prairie Island Unit 2 (PI-2)

Prairie Island Unit 2 uses Model 51 SGs with partial depth roll expansion. The original roll expanded length was approximately 2.75 inches into the tubesheet; the remaining tube length within the tubesheet (approximately 18.28 inches) was unexpanded. The PI-2 data management reports were used to develop the trending data described below.

PWSCC at the expansion transition (i.e., approximately 2.75 inches above tubesheet primary face) was first observed at 11.92 EFPY when one tube was reported to be affected in SG21. PWSCC is next reported at 15.88 EFPY; 11 tubes were affected thus the 0.1% level is at 15.88 EFPY. The RPC scope was <100% so an accurate indication count cannot be established for this inspection. PWSCC within the tack roll region was first reported at 17.27 EFPY. To date, approximately 44% of the hot leg tubes have been affected by PWSCC within the roll expanded region but only about 13% have been affected at the tack roll. This evaluation considers any flaw within 1 inch of the tube end as a tack roll region flaw, thus the tube end indication counts may be slightly artificially elevated. As only 2.75 inches of tube length form the expanded length, the entire expanded length, including the tack roll region, is routinely inspected with RPC probes. A 20% sampling of the cold leg expanded regions was performed at 18.81, 21.59, 24.66, and 27.52 EFPY; no indications were reported. Thus, it is likely that PWSCC does not exist on the cold leg side at PI-2. The PI-2 experience suggests a reduced initiation potential for the tack roll compared to the roll expansion transition (2.75 inch above tube end in this case).

5.7 ESTIMATE OF NUMBER OF COLD LEG INDICATIONS AT SQN UNIT 2

The current T-hot is 611°F while the current T-cold is 544°F. Using an Arrhenius equation with activation energy of 50 kcal/mole an improvement factor of 16 is developed. Note that the PWSCC initiation activation energy of 50 kcal/mole has been widely used in the US. The SQN-2 and Farley 1 cold leg inspection results can not confirm this improvement factor as sufficient operating experience is not achieved but do confirm a temperature dependency of PWSCC and ODSCC.

5.7.1 Top of Tubesheet and Expanded Region in Tubesheet

The PWSCC cumulative trending shown on Figure 5-9 is used to estimate the number of postulated cold leg PWSCC indications. Based on the cold leg sampling performed at EOC-12, it is possible, but unlikely, that 4 indications per SG or a total of up to 16 may have been present at this time (16 EFPY). As zinc injection was initiated at about 15 EFPY, the projected cold leg indication counts will conservatively add to the hot leg indication counts post zinc injection a total of 16 at 16 EFPY. Through the next outage, EOC-16 (20 EFPY), 25 indications might be expected on the cold leg in the proposed inspection distance. If all 25 are assumed in one SG, and the hot leg elevation distribution is applied, 22 could be located within 4 inches of the top of tubesheet and 3 could be located at greater than 4 inches below the top of the tubesheet. Through the projected replacement date of Fall 2012 up to 32 indications could be expected. TVA is proposing that a 20% +Pt sample of the cold legs in each SG be performed at EOC-16. If the 25 postulated indications are equally distributed amongst the SGs, 6 to 7 indications in each SG could be present. With a 20% sampling there is a 70 to 75% probability that at least one of the 6 to 7 indications in each SG will be sampled. If no indications are observed at EOC-16, sampling of the cold legs will not be performed at EOC-17.

The 0.1% affected level for ODSCC was not achieved on the hot leg until 11.98 EFPY. This document has suggested the appropriate time to be applied is 10.56 EFPY. Considering the cold leg inspection histories of the other plants discussed, ODSCC is not expected on the cold leg at EOC-16.

The Farley 1 cold leg inspection history shows no cold leg SCC was reported through 16.38 EFPY. The Farley 1 T-cold was 543°F, thus the results can be applied directly to SQN-2 without adjustment. Figure 5-10 presents a cumulative plot of both PWSCC and ODSCC hot leg indications. The single ODSCC indication reported at about 4.2 EFPY is likely either a false report or a PWSCC indication which was inadvertently reported as ODSCC. Notice that ODSCC is not reported again until about 12 EFPY. The Farley 1 ODSCC totals are significantly greater than SQN-2. Through 16.38 EFPY, Farley 1 had reported approximately 1200 tubes affected with ODSCC at the top of tubesheet and sludge pile regions. Through 18.6 EFPY SQN-2 has reported only about 100 indications. Considering that Farley 1 had reported no SCC on the cold leg, the likelihood that SQN-2 contains ODSCC indications at the cold leg top of tubesheet or sludge pile region is low.

5.7.2 Tack Roll Region

Using an Arrhenius equation and PWSCC initiation activation energy of 50 kcal/mole, an estimate can be made of the potential for PWSCC at the cold leg tube ends for SQN-2. For the cold leg temperatures of SQN-2 and PI-2, the SQN-2 susceptibility is 1.89 times greater than PI-2. Thus as PI-2 has not reported cold leg PWSCC through 27.52 EFPY, PWSCC would not be expected at SQN-2 prior to 27.52/1.89 = 14.56 EFPY. Use of a smaller activation energy (say 40 kcal/mole) would result in a smaller factor (1.67) which would predict the first cold leg tube end PWSCC at no sooner than 27.52/1.67 = 16.48 EFPY.

A Weibull analysis of the available expansion transition and tack roll region data indicates that the incidence rate (slope) is reduced for the tack roll region compared to the expansion transition. Figure 5-11 presents a Weibull analysis which includes the SQN-2 hot leg PWSCC data for reference, Farley 2 hot leg PWSCC data, Prairie Island 2 hot leg expansion transition data, and Prairie Island 2 hot leg tack roll region data. The slope is reduced and characteristic time is longer for the tack roll than the expansion transition. The Farley 2 plot of Figure 5-11 is not normalized to the Prairie Island 2 temperature. When the Farley 2 data is normalized to the Prairie Island 2 hot leg temperature, the times associated with various percent affected levels are nearly two times the Prairie Island 2 tack roll times. Comparing the PI-2 expansion transition and tack roll times, an average of 1.5 is observed. Thus an estimate of the number of tack roll indications can be made by using the PI-2 tack roll data with an adjustment for the stress level and adjustments for hot leg to cold leg temperature.

The total or effective stress drives the flaw. The effective stress includes residual stresses due to manufacture, thermal stress, and pressure or operating stresses. If it is assumed that the residual stress due to manufacture is equal, comparing the top of the tubesheet with the tack roll, the top of the tubesheet would be expected to have a higher thermal stress due to the tube ID and OD temperatures, which vary significantly. At the tack roll the tube temperature is essentially constant across the tube wall. Additional bending stresses can be introduced at the top of tubesheet due to tubesheet bow which are not present at the tube end region. Thus, it is reasonable that comparison of the Weibull analysis for Farley 2 and the PI-2 tack roll region would include a larger difference than for the comparison of the PI-2 expansion transition and tack roll regions. The predicted Weibull plot for the SQN-2 cold leg tack roll region is also provided on Figure 5-11. This plot was developed by adjusting the PI-2 tack roll data by the minimum empirical improvement factor for Farley 2 of 3.5 then adjusting by 0.53, which normalizes the PI-2 cold legs to the SQN-2 cold leg temperature. The incidence levels assumed are the PI-2 incidence levels. The 0.1% affected level is achieved at approximately 18 EFPY and the 1% affected level is achieved at approximately 32 EFPY. This evaluation has no significance with regards to leakage estimation but is provided to show that the likelihood of cold leg tube end cracking without the influence of an additional stress input (i.e., deplugging) is low and is not expected to affect a large percentage of tubes. The influence of zinc addition is not included in the estimate of cold leg tack roll incidence.

5.8 CALCULATION OF SLB CONDITION LEAKAGE AT EOC-17 AND FUTURE OPERATIONAL ASSESSMENT PERIODS

Section 5.1 has assigned a conservative estimate of 25 indications in the 8 to 12 inch elevation on the hot leg side of SQN-2 for EOC-16, and is developed using the most up to date eddy current inspection results. Thus, the previously developed estimate of 41 indications through EOC-13 is conservative and the SLB condition leakage allowance of 0.18 gpm for the hot legs is conservative. This elevation range is below the hot leg W* inspection depth. In order for this number to be exceeded, the indication distribution at EOC-16 would have to dramatically change from the historical trending. There is sufficient margin in the estimate of indications that over 100 hot leg indications would have to be observed in order for the leakage estimate to exceed this number. Considering that only 3 hot leg indications were reported for each of the last two inspections it is highly unlikely that the previously established SLB condition leakage allowance will be exceeded.

Any observed cold leg indications will be evaluated for leakage contribution using the observed EOC-16, cold leg indication elevation distribution at the upper 95% prediction. The estimated indication count at 8, 9, 10, and 11 inches (from the to-be-developed cold leg 95% prediction bound) will be multiplied by the allowance of 4.5×10^{-3} gpm. If no cold leg PWSCC indications are detected at EOC-16, no SLB leakage contribution from postulated indications below the applied inspection distance will be included. If cold leg PWSCC indications are detected the applied hot leg allowance of 9×10^{-5} gpm per inservice tube in the faulted SG for postulated indications greater than 12 inches below the top of the tubesheet will be included. The SG with the largest number of inservice tubes will be assumed to be the faulted SG. The prediction for the cold legs will imply a greater confidence in the developed value as the applied inspection distance will be a minimum of 10.5 inches below the top of the tubesheet. As additional RPC inspection data is acquired to ensure that each tube is inspected to the appropriate distance, it is likely that the actual inspection distance applied to the cold leg will exceed 11 inches below the top of the tubesheet.

5.9 RIS 2007-20 Considerations

US NRC RIS 2207-20 (Reference 5.2) questioned the definition and treatment of the limiting accident condition. The pressure-time histories of the postulated accident conditions (i.e., locked rotor, control rod ejection, and SLB/FLB) were reviewed.

5.9.1 Background

Primary-to-secondary leakage is assumed to occur in several design basis accidents (e.g., feedwater line break or steam line break, locked rotor, control ejection). The radiological dose consequences associated with this assumed leakage are evaluated to ensure that they remain within regulatory limits (e.g., 10 CFR Part 100, 10 CFR 50.67, GDC 19). The accident induced leakage performance criteria are intended to ensure the primary-to-secondary leak rate during any accident does not exceed the primary-to-secondary leak rate assumed in the accident analysis. Radiological dose consequences define the limiting accident condition for the W* justification.

5.9.2 Pressure-Time Histories for Accidents that Model Primary-to-Secondary Leakage

As noted in Reference 5.3, implementing the accident induced leakage performance criteria requires an analysis of the condition of the steam generator tubing during a steam generator inspection to calculate the magnitude of the primary-to-secondary leakage which could potentially occur for each of the design basis accidents. The calculated leak rates for each design basis accident should not exceed the value assumed in the corresponding accident analyses.

To make such a comparison for W*, the generic transient response curves for 4-loop plants was reviewed to define the loading conditions on the tubes for each of the accidents that model primary-to-secondary conditions for SQN-2. The transients considered are:

- Steam Line Break
- Feed Line Break
- Reactor Coolant Pump Locked Rotor – Dead Loop
- Control Rod Ejection

The locked rotor and control rod ejection events are of short duration and decay to pressure and temperature conditions which are bounded by normal operating conditions. For the locked rotor event, the RCS pressure drops to below 2250 psia by about 20 seconds into the event and RCS pressure over the remaining duration of the event never exceeds 2250 psia. Steam pressure will be increased to the no load condition upon main steam isolation valve (MSIV) actuation thus pressure differential is reduced. For the control rod ejection event the RCS pressure drops to below 2250 psia by about 5 seconds into the event, and RCS pressure over the remaining duration of the event never exceeds 2250 psia. Steam pressure will be increased to the no load condition upon MSIV actuation thus pressure differential is reduced. For these events, cumulative leakage should be essentially equal to normal operating condition leakage, and thus are not significant.

Thus the limiting radiological event is either the FLB or SLB event. As the leakage test data is based on a pressure differential of 2650 psi and 600°F, the limiting radiological event remains bounded by the leakage test data.

5.9.3 Limiting Transient

The limiting transient is defined based on radiological dose consequences. For the steam line break event it is judged that a plant cool down event would occur while for the feedwater line break either a heatup or cool down event could occur depending upon the size of the break and plant operating conditions at the time of the break. For the cool down event the Updated Final Safety Analysis Report (UFSAR) indicates the SLB case is controlling. For the heatup event, the reactor coolant average temperature is assumed 5.5°F above the nominal value and reactor coolant pressure is 30 psi above nominal at initiation of the event. The reactor coolant system (RCS) pressure plots contained in the FSAR indicate that the peak pressure during recovery (<2400 psia) is well bounded by the test pressure of the leakage specimens. Cold leg temperature remains bounded by 600°F for the duration of the event. The cold leg temperature drops to about 440°F between 100 and 200 seconds, has a peak recovery temperature at about 10,000 seconds and begins to decay from the peak. The leakage trending equation of Section 4.5 (used for trending purposes only), as well as other industry applied leakage methods including a modified form of the Darcy Equation, include the viscosity term in the denominator. Thus as the viscosity term increases with decreasing temperature, calculated leakage is decreased for decreasing temperature, when all other factors remain unchanged. Therefore, an increase in leakage due to a reduction in RCS fluid temperature compared to the leakage model would not be expected to occur.

5.9.4 Feedwater Line Break Plant "Best Estimate" Transient Discussion

For application to W*, it is judged that the use of the SG design specification to define the plant conditions following a postulated FLB is overly conservative (which results in an excessive plant FLB heat-up). The objective of the design specification curves for this one-time postulated event for the lifetime of the plant is to ensure that the component structural integrity and consequences of this event remain within acceptable limits. Reference 5.4 indicates that the "best estimate" transient involves a cool-down event opposed to a heatup event.

In accordance with plant emergency operating shutdown procedures, it is expected that the operator would take action following a high energy secondary line break to keep the plant at a safe hot shutdown condition. The expectation for a FLB with credited operator action is to control the system temperature to the normal operating no load temperature. During the time of the dose calculation, the operator action initiates a cool-down and depressurization of the reactor coolant system.

Precedent exists to credit operator action with respect to the FLB. The SG tube rupture event in the Updated Final Safety Analysis Report (UFSAR) permits operator action to mitigate the expected leakage. The UFSAR Chapter 15 calculation of the dose consequences for the SLB will continue to be extremely bounding since the release rate calculation continues to use the Technical Specification limit value without crediting the operator actions that will occur to terminate the leakage through the SG.

The FSAR Chapter 15 analyses are also extremely conservative with respect to a realistic break outside containment. For example, environmental errors that are applied to reactor trip and emergency safety feature (ESF) actuations would no longer be applicable. This would greatly improve the heat removal capability of the SGs for the transient.

Because the best estimate FLB transient temperature does not exceed the temperature applied to the leakage testing, the viscosity term increase should act to reduce actual leakage compared to the applied model.

Based on the above, it is concluded that a qualitative comparison with the radiological consequences of a SLB still applies for a postulated SLB.

REFERENCES

5.1 Nuclear Engineering and Design 143(1993), "Residual Stresses Associated with the Hydraulic Expansion of Steam Generator Tubing into Tubesheets," March 1993

5.2 US NRC RIS 2007-20, "Implementation of Primary-to-Secondary Leakage Performance Criteria"

5.3 Revised September 2008 Monthly Report for the Job Code N6582, Argonne National Laboratory, Argonne, IL

5.4 WCAP-9230, "Report on the Consequences of a Postulated Main Feedline Rupture," January 1978

Figure 5-1

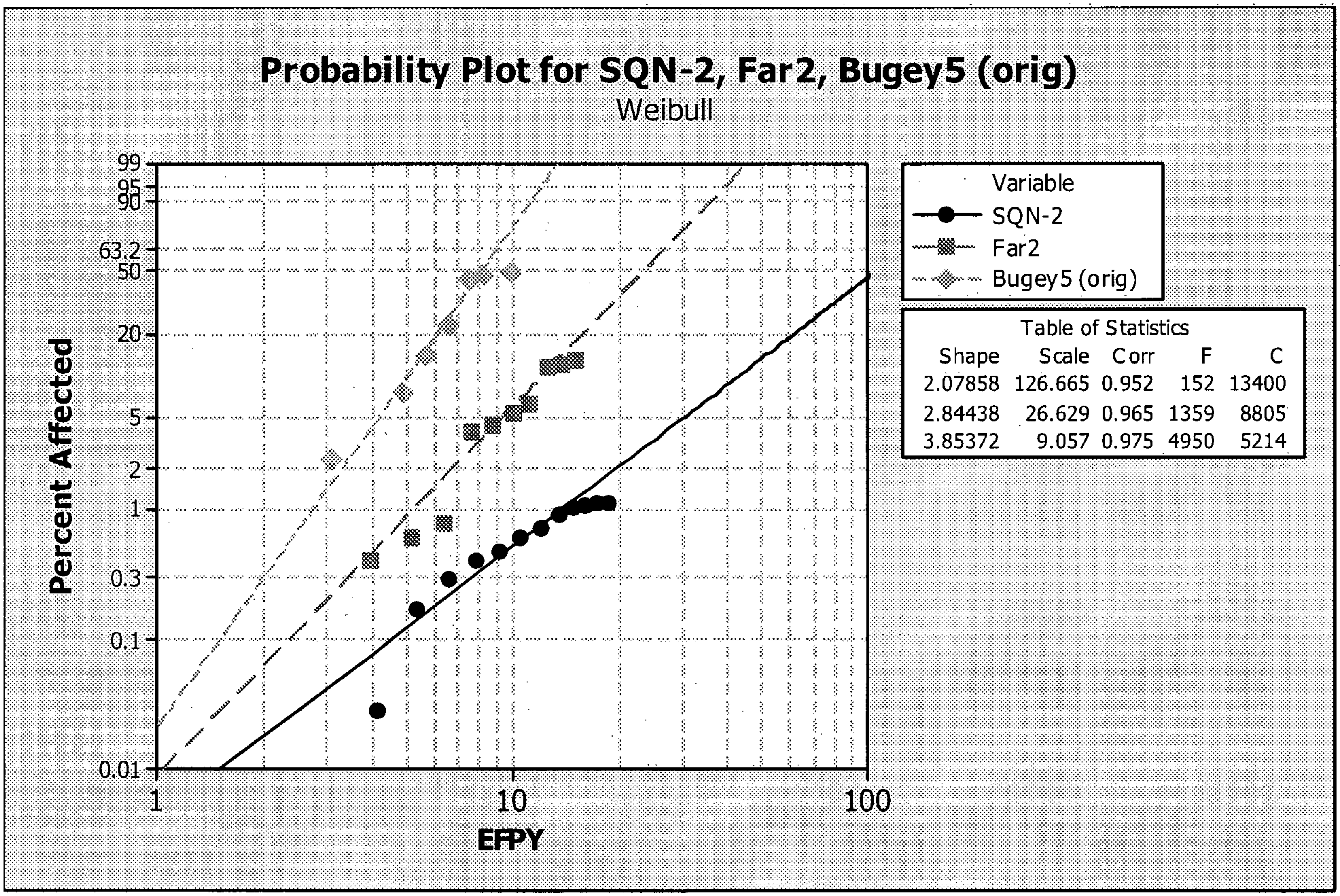
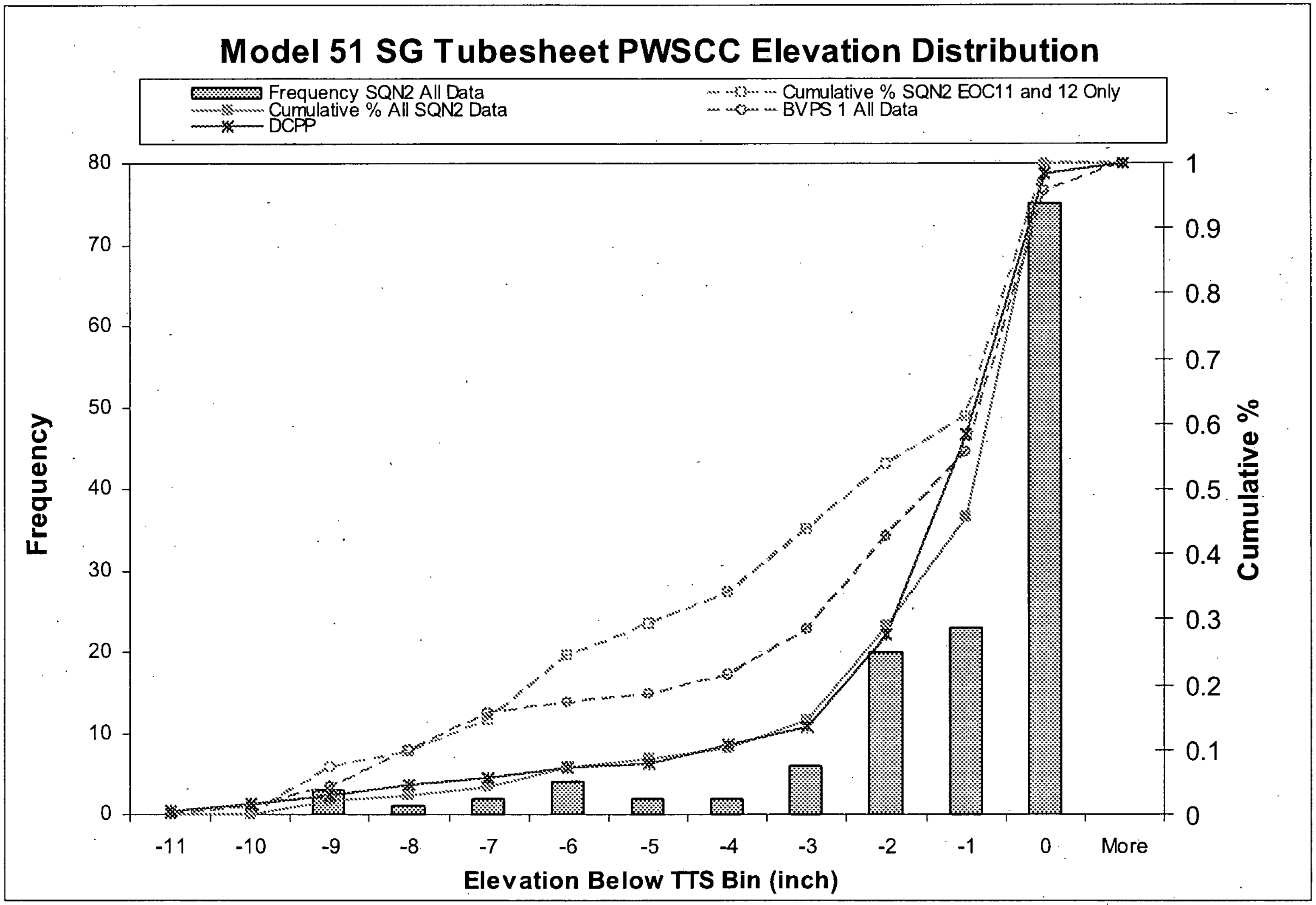
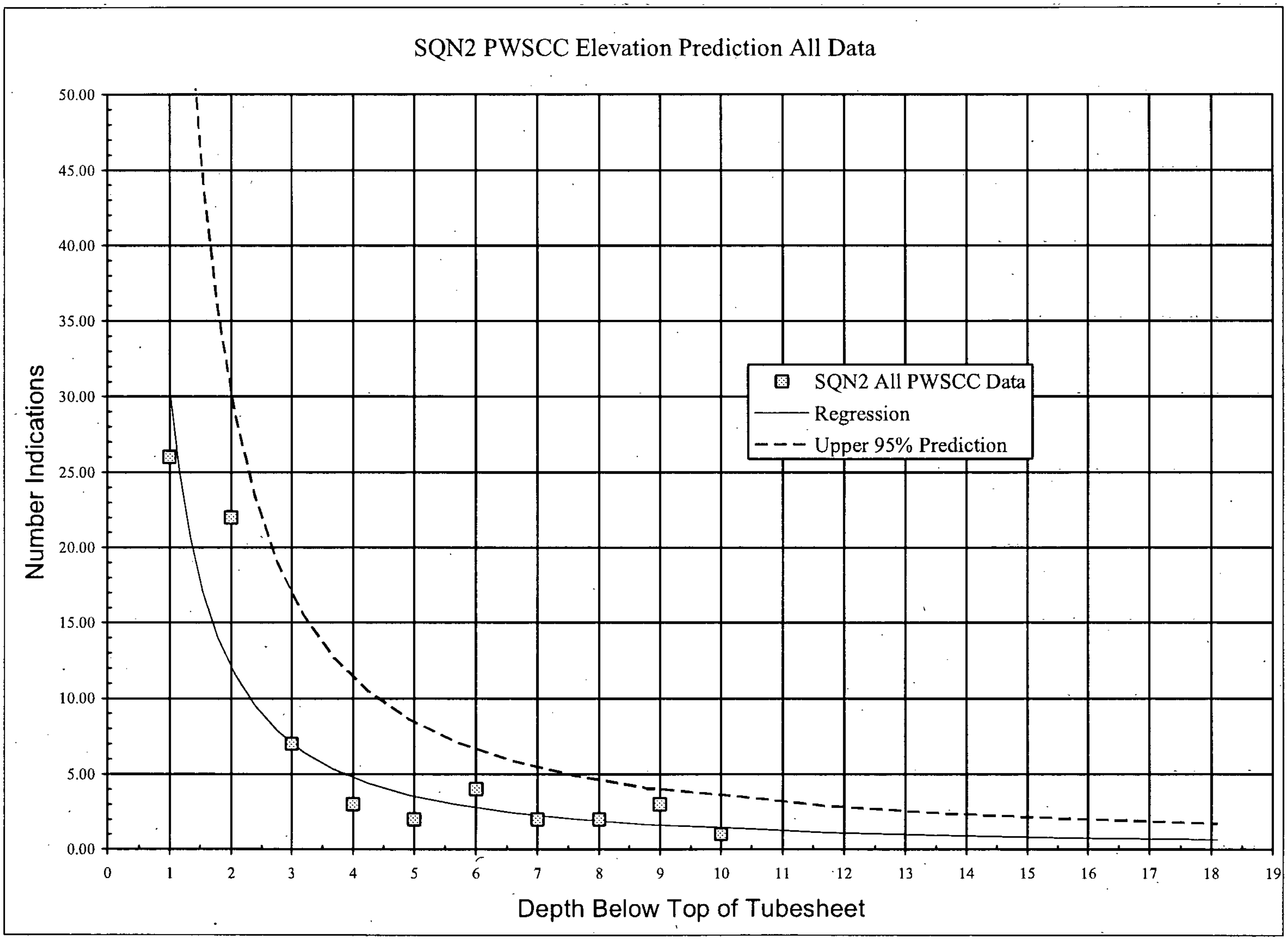

Probability Plot for SQN-2, Far2, Bugey5 (orig)
Weibull
Percent Affected
99
95
90
63.2
50
20
5
2
1
0.3
0.1
0.01
1
10
100
EFPY
Variable
SQN-2
Far2
Bugey5 (orig)
Table of Statistics
Shape Scale Corr F C
2.07858 126.665 0.952 152 13400
2.84438 26.629 0.965 1359 8805
3.85372 9.057 0.975 4950 5214

Figure 5-2



Model 51 SG Tubesheet PWSCC Elevation Distribution
Frequency SQN2 All Data
Cumulative % All SQN2 Data
DCPP
Cumulative % SQN2 EOC11 and 12 Only
BVPS 1 All Data
Frequency
Cumulative %
80
70
60
50
40
30
20
10
0
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
-11
-10
-9
-8
-7
-6
-5
-4
-3
-2
-1
0
More
Elevation Below TTS Bin (inch)

Figure 5-3



SQN2 PWSCC Elevation Prediction All Data
Number Indications
Depth Below Top of Tubesheet
50.00
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
SQN2 All PWSCC Data
Regression
Upper 95% Prediction

Figure 5-4

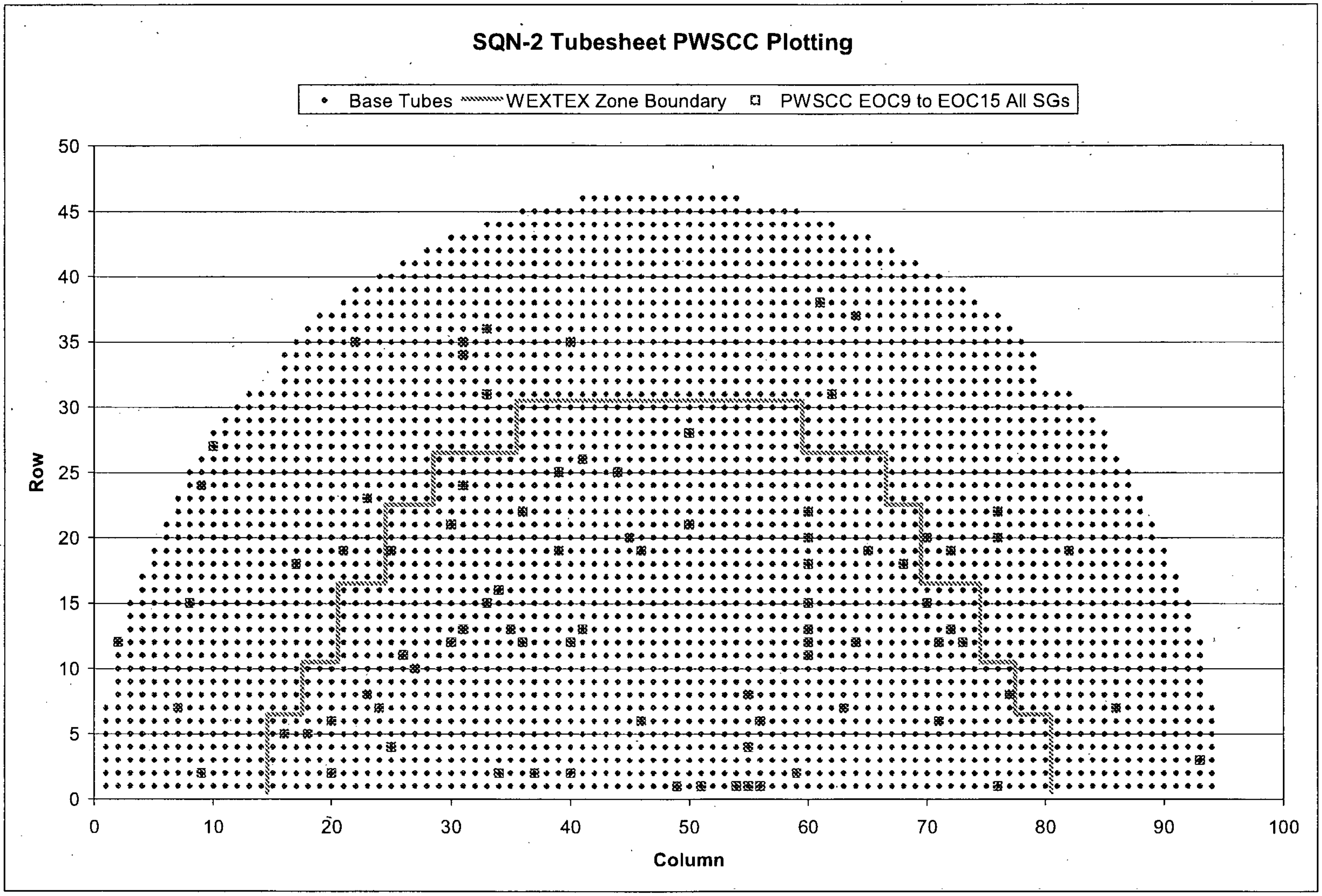

SQN-2 Tubesheet PWSCC Plotting
Base Tubes
WEXTEX Zone Boundary
PWSCC EOC9 to EOC15 All SGs
Row
Column
0
5
10
15
20
25
30
35
40
45
50
0
10
20
30
40
50
60
70
80
90
100

Figure 5-5

a,c,e

Figure 5-6

a,c,e

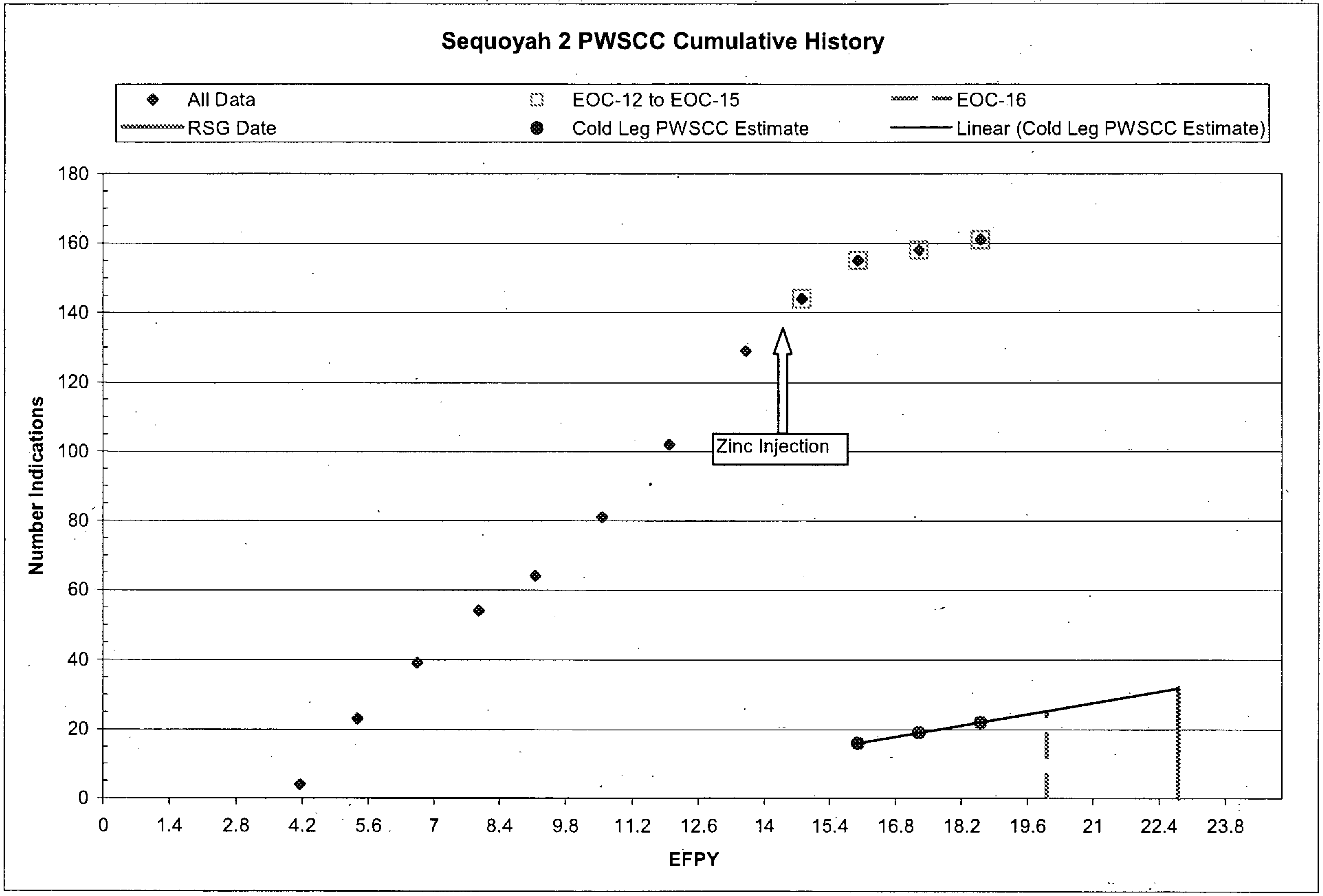
a,c,e

Figure 5-7

Figure 5-8

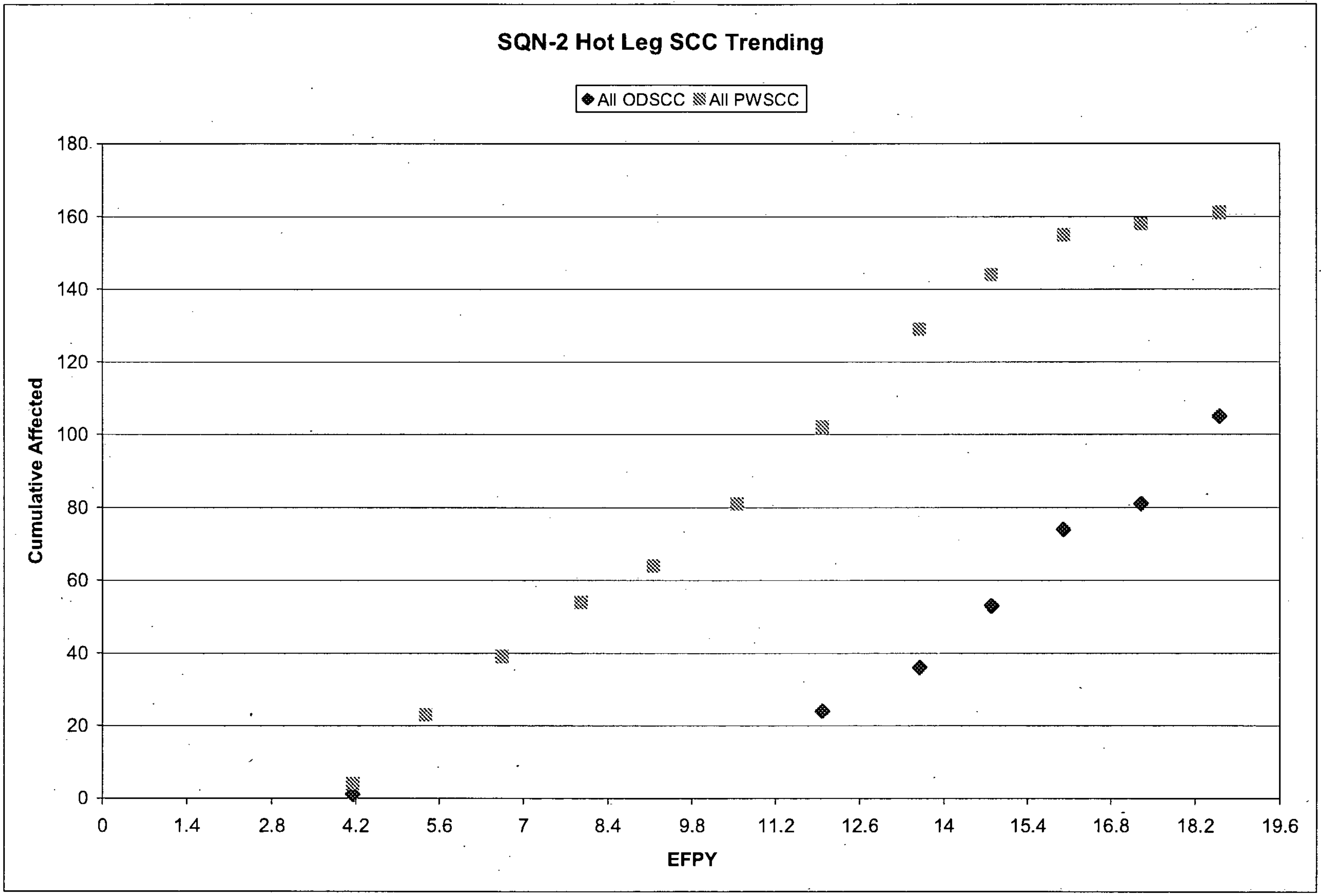
a,c,e

Figure 5-9



Sequoyah 2 PWSCC Cumulative History
All Data
EOC-12 to EOC-15
EOC-16
RSG Date
Cold Leg PWSCC Estimate
Linear (Cold Leg PWSCC Estimate)
Zinc Injection
Number Indications
EFPY
0
20
40
60
80
100
120
140
160
180
0
1.4
2.8
4.2
5.6
7
8.4
9.8
11.2
12.6
14
15.4
16.8
18.2
19.6
21
22.4
23.8

Figure 5-10



SQN-2 Hot Leg SCC Trending
All ODSCC
All PWSCC
Cumulative Affected
180
160
140
120
100
80
60
40
20
0
0
1.4
2.8
4.2
5.6
7
8.4
9.8
11.2
12.6
14
15.4
16.8
18.2
19.6
EFPY

Figure 5-11

a,c,e

6.0 SEQUOYAH UNIT 2 RESPONSE TO PREVIOUS NRC RAIs

The NRC staff has previously transmitted further requests for additional information (RAIs) to utilities planning to implement the W* plugging criterion. The SQN2 responses to the previous RAIs that are applicable to a plugging criterion that utilizes a *non-degraded W* length (i.e., no service induced degradation is present)* are provided below. The responses have been grouped into three categories: inspection results summary, structural analysis related and steam line break leakage considerations. The RAI responses from the SQN-2 W* hot leg submittal, Salem 2 W* submittal, and recent H* RAI responses were reviewed for applicability.

6.1 INSPECTION RESULTS SUMMARY

6.1.1 Discussion of Inspection History at Sequoyah Unit 2 (Callaway RAI # 18 and # 23, St. Lucie Unit 2 RAI #26)

Table 6-1 presents a summary of the axial and circumferential PWSCC for the last five outages at SQN2. Zinc injection was initiated prior to the U2C12 inspection. A noticed decrease in indication counts is observed for U2C13, U2C14, and U2C15.

Table 6-1

	SG 1		SG 2		SG 3		SG 4	
Inspection	Axial	Circ	Axial	Circ	Axial	Circ	Axial	Circ
U2C11 (2002)	5	0	3	3	3	1	5	7
U2C12 (2003)	1	0	5	1	3	3	1	0
U2C13 (2005)	0	1	3	1	1	0	5	0
U2C14 (2006)	0	0	0	1	0	0	2	0
U2C15 (2008)	0	0	0	0	1	0	2 (1)	1
Total	6	1	11	6	8	4	15	8

(1): One tube affected at cold leg tube end. Tube was previously plugged, deplugged and returned to service.

6.1.2 Discussion of Industry Experience (Callaway RAI # 23 and # 65)

As noted above, a distribution of indications has been conservatively defined for the WEXTEX Region of the SQN2 steam generators. The potential occurrence of cold leg indications for SQN-2 will be based on inspection results from the EOC-16 inspection and will be from an upper 95% prediction bound to the data fit. Indications below the expansion transition region are believed to be caused by tubesheet hole drilling anomalies during manufacture, and the propensity for tube indications at tube hole surface anomalies was shown in a previous Westinghouse laboratory program involving hydraulically expended joints. It is assumed that potential corrosion of the WEXTEX tube joints would be similar because the anomalies would be sites of locally elevated residual stress. It is also based on the lack of indications in smooth bore, anomaly-free tube holes in hydraulically expanded joints (Alloy 600 tubes) in a laboratory program performed by Westinghouse for EPRI.

6.2 STRUCTURAL ANALYSIS

6.2.1 Determine Impact of Locked Tubes on W* (Diablo Canyon RAI # 1)

Locked tube residual axial loads occur because of packing and/or denting of the tube-to-tube support plate crevice while the plant is operating, i.e., when the tube is strained in the axial direction by primary-to-secondary pressure end cap load. Hence, the residual load in the tube is equal to the normal operating load. When the plant cools, a portion of the residual strain, and the attendant residual load remains. When the plant returns to power, the load at operating conditions is restored to the same level that was present when the locking occurred, i.e., at normal operating conditions. Since the TSP is restored to the elevation it occupied at the time of locking, it imparts no additional load on the tube. In other words, as the pressure load increases strain in the tube, the residual downward load of the tube on the TSP decreases. The W* criteria were developed to provide a margin of safety of three relative to the loads corresponding to normal operating conditions.

The second effect of the locked tube loading is the Poisson contraction of the tube in the hoop and thickness direction. Again, the axial stress conditions in the tube during operation are unaffected by locking of the tube at the TSP. The tensile test results used to demonstrate that the value used for the coefficient of friction were from conservative test programs. The equations used to calculate the coefficient of friction also did not account for the axial load, hence, the calculated values for the tests are lower than the actual values. Moreover, the configuration of the tensile tests also results in a Poisson contraction of the tube over the full range of the test load. This is conservative relative to demonstrating the factors of safety relative to the requirements of RG 1.121, e.g., testing to 3 times the required axial force results in a Poisson contraction three times that of the nominal condition.

In summary, implicitly ignoring the potential effects of the tube being locked at the TSPs is conservative to determining the W* value. Even if a loss of engagement is postulated to be possible, and the effect of the locked condition is evaluated, the locked condition has no effect on the required W* length. Therefore, the implicit assumption that the tubes are not locked at the TSP is either conservative or not significant to the determination of W* (Reference 6.1).

6.2.2 Impact of Tubesheet Bow on Pull Out and Leak Rate Testing (St. Lucie 2 RAI # 8, Callaway RAI # 8 and #55)

Tubesheet bow is the flexing of the tubesheet in response to the primary-to-secondary side pressure difference which results in a dilation of the holes above the mid-plane of the tubesheet during normal operation and postulated faulted conditions. The contact pressure decreases above and increases below the approximate mid-plane[4] of the tubesheet. The dilation does not have to be simulated since it can be treated analytically using the Theory of Elasticity.

In situ leak rate tests are conducted at ambient conditions and there is no differential pressure across the tubesheet. Thus, there are two conditions that are atypical of normal operating and postulated accident conditions. In summary, the increase in temperature tends to make the joint tighter, and the increase in differential pressure across the tubesheet will tend to make the joint looser. In addition, for structural integrity testing, the increase in pressure internal to the tube will act to tighten the joint and increase the strength of the joint. Thus, the act of testing may bias the results in a non-conservative manner at the elevation of the degradation being tested. It is noted that there is no hole dilation at the location of the neutral plane of the tubesheet, slightly below mid-plane, and such testing which results in no leakage is indicative of operating and accident condition results to be expected at lower elevations within the tubesheet.

In situ structural testing is not likely to be meaningful in demonstrating compliance with performance criteria, i.e., demonstrating a resistance to pull out of greater than three times the normal operating pressure differential. Morever, the difference in contact pressure during in situ testing means that the leak rate data cannot be used directly to quantify potential leak rates. This does not mean that an analytical procedure could not be developed to deal with such quantification; that is the basis for correlating the leak rate to the inverse of the loss coefficient and further correlating the loss coefficient to the tube-to-tubesheet contact pressure.

The effect of tubesheet bow can result in an average decrease in the contact pressure during postulated accident condition for the Model 51 tubes. For the tubes tested to date, in situ testing resulted in no measurable leakage. However, the contact pressure during the performance of the in situ test was significantly less than the contact pressure present when the laboratory tests where performed, almost all of which leaked. Note the laboratory leakage tests used drilled holes to provide a leakage path from the tube ID to tube OD. Thus the leak rate tests performed in situ are relevant to demonstrating whether or not an indication leaks. Although the leak rate from a leaking indication may not lend itself to a precise quantified prediction of the leak rate during operation, it can be used to estimate whether or not the leak rate would be significant during operation or postulated accident conditions.

During the Fall 2003 inspection at a plant with Combustion Engineering (CE) steam generators, a 1.9 V (by + Point), 140° arc length, 99% through-wall (by phase angle) circumferential crack

---

4 The location of the neutral plane of the tubesheet is slightly below the mid-plane because of the membrane stress caused by the distributed pressure load.

(PWSCC) at the top of the tubesheet was in situ tested with no leakage being reported at the postulated SLB pressure difference.

It is also believed that effects of tubesheet bow, which cannot be modeled by test, will add significantly to the pull out resistance. As the tubesheet flexes the tubes will act to resist the flexure, adding to the contact pressure but the flexure of the tubesheet is expected to overcome the tube resistance. Tubes are also expected pick up side loading at the lower TSPs. This side loading coupled with the tubesheet flexure displaces the tube axis relative to the tube hole axis. This creates an unbalanced load path which creates a bending "lockup." Evidence supporting this and confirmation that axial resistive load capability is significantly increased can be seen in the testing described in WCAP-14201 (Reference 6.2). In this program, the structural capability of sleeved tubes repaired with hybrid expansion joint (HEJ) sleeves was investigated. In particular, the structural capability of the freespan upper joint was investigated. Simulations of parent tube degradation at the bottom of the roll expansion flat length were produced by machining 180° and 240° through-wall flaws using a thin slitting saw. Upon loading the unbalanced load path caused lockup of the joint such that the resistive load capability was increased over specimens machined with 360° flaw simulations. In some cases, testing was halted due to general yielding of the sleeve in tension. Thus the degraded joint was stronger than the sleeve itself. A similar condition would be expected with bending of the tubesheet.

Such conditions, which conservatively add to the integrity of the joint cannot be simulated for tube-in-tubesheet conditions without great expense but engineering fundamentals supports their contribution.

6.2.3 Tube Pull Out Testing Description (Callaway RAI # 25)

The pull out testing program and results are described in the "Pullout Test Specimen Descriptions" section of WCAP-14797, Rev. 2, Section 4.2.2, and is summarized below.

The W* pull out test samples were selected from a number of specimens prepared in the W* program to provide a lower bounding case condition with regard to pull out resistance. The W* pull out samples consisted of carbon steel collars approximately 4 inches in length, 2.25 inches in outside diameter and 0.890 inch in inside diameter. Expanded into each collar by the WEXTEX process was mill annealed Alloy 600 (ASME SB-163) steam generator tubing section approximately 12 inches in length. The tube yield strength was 58 ksi. The nominal unexpanded outside diameter of the tube was 0.875 inches.

Since the WEXTEX expansion is a high energy process which causes the tube OD to impact and to be deformed into even small variations in the tubesheet hole bore surface, the feature which is of most significance is the surface finish of the tubesheet hole. The Series 51 SG tubesheet hole requirement was 250 microinch rms maximum. The samples in the test program were procured to a 100 to 250 rms requirement. For the W* pull out tests, two tubesheet collar specimens were selected, one specimen which appeared to have a bore surface roughness at the upper end of the bore finish requirements, and one with a smooth finish. Both of tubesheet collar specimens had uniform diameter profiles.

The collars used to simulate the tubesheet were fabricated from 1018 cold rolled carbon steel round bars with mechanical properties similar to that of the tubesheet material. The collar inside diameter was selected to match these size holes in the Model 51 tubesheet and the outside diameter was selected to provide the same radial stiffness as the tubesheet hole.

The WEXTEX samples fabricated for pull force testing were of a double ended configuration. After WEXTEX expansion, the samples were qualitatively checked for joint tightness. About 70% of the specimens exhibited a slight degree of looseness in the hoop direction in that it was possible to rotate the tube by an estimated 1 or 2 degrees (1°≈7 mils on the tube OD). These specimens were fabricated to provide tube hole surface finish consistent with actual SG tube holes and were expanded using the same process as the SQN-2 SGs. Thus it can be concluded that the specimens are representative of the actual SG condition. For a full length (approximate 18 inch WEXTEX expanded length) it is not expected that any rotational looseness would be present.

The samples were also noted to have [

]b,c,e

6.2.4 Tubesheet Finite Element Model Discussion (Callaway RAI # 27 and # 43)

Loads are imposed on the tube as a result of tubesheet bowing under various pressure and temperature conditions. The finite element analysis of the tubesheet, channelhead, and lower shell were performed to determine the unit displacements throughout the tubesheet for two pressure unit loads (primary and secondary side) and three thermal unit loads (tubesheet, shell, and channelhead). The analysis yielded the unit displacements throughout the tubesheet for these five unit loads. The normal operating and faulted conditions (pressure and temperature) were then applied to these unit displacements for calculating the tube-to-tubesheet contact pressure distribution from the top to the bottom of the tubesheet.

The pressure and temperature parameters for the feed water line break, steam line break, and loss of coolant accident (LOCA) events were from a generic accident analysis. It is shown in Section 3.0 of this report that the generic temperature and pressure parameters used in the structural analysis bound the values used in the accident analysis of the SQN2 steam generators.

6.2.5 Ligament Tearing Discussion (Callaway RAI # 30)

One of the concerns that must be addressed in dealing with cracks in SG tubes is the potential for cracked tube radial ligament tearing to occur during a postulated accident when the differential pressure is significantly greater than during normal operation. While this is accounted for in the strength evaluations that demonstrate a resistance to pull out in excess of $3 \cdot \Delta P$ for normal operation and $1.4 \cdot \Delta P$ for postulated accident conditions, the potential for ligament tearing to significantly affect the SLB leak rate predictions needs to be addressed.

Ligament tearing considerations for circumferential tube cracks that are located below the W* depths within the tubesheet are significantly different from those for potential cracks at other locations. The reason for this is that W* has been determined using a factor of safety of three relative to the normal operating pressure differential and 1.4 relative to the most severe accident condition pressure differential. Therefore, the internal pressure end cap loads which normally lead to an axial stress in the tube are not transmitted below about 1/3 of the W* depth. This means that the only source of stress acting to extend the crack is the primary pressure acting on the flanks of the crack. Since the tube is captured within the tubesheet, there are additional forces acting to resist opening of the crack. The contact pressure between the tube and tubesheet results in a friction induced shear stress acting opposite to the direction of crack opening, and the pressure on the flanks is compressive on the material adjacent to the plane of the crack, hence a Poisson's ratio radial expansion of the tube material in the immediate vicinity of the crack plane is induced which also acts to restrain the opening of the crack by increasing the contact pressure between the tube and the tubesheet. In addition, the differential thermal expansion of the tube is greater than that of the carbon steel tubesheet, thereby inducing a compressive stress in the tube below the W* length.

A scoping evaluation of the above effects was performed by ignoring the forces that resist the crack opening, and simply looking at the effect of the pressure acting to open the crack. If a 360° through-wall crack is considered, the stress from the pressure on the flanks is 0.206 or 20.64% of the stress that would result from an end cap pressure load for the same pressure. The primary pressure during normal operation and during a postulated accident is 2250 and 2665 psia, respectively. The actual pressure difference between accident and normal operating conditions is 415 psi or 18% and the relative effect is equivalent to a change in pressure of 100 psi or 4% if the source of the stress were the end cap pressure differential.

The magnitude of the effect can also be used to conservatively estimate the ligament thickness of tube material affected. Using the ASME Code specified minimum yield stress of 35.2 ksi at 650°F, the applied forces can be calculated as if the pressures were applied to the entire cross-sectional area of the tube material, thus representing the maximum force that can be applied to the tube as the result of a pressure on the crack flanks. These calculated maximum forces are 290.9 and 349.6 lbs at internal pressures of 2250 and 2665 psia, respectively. So as not to exceed the yield stress, less than 9% of the cross-sectional area of the tube is required to resist the maximum force of 344.6 during a postulated accident. This equates to a circumferential crack that extends 360° and is 92% through-wall, i.e., the remaining material is less than 3.5 mils thick. The corresponding value for the normal operating condition is a little more than 3.0 mils. Thus, the difference in required wall thickness between the normal operation and accident condition pressures is on the order of 0.5 mil. If the resisting forces discussed above were to be included in this evaluation, the difference would be significantly less.

In summary, considering the worst-case scenario, the likelihood of ligament tearing from radial circumferential cracks resulting from an accident pressure increase is small since at most, only 8% of the cross-sectional area is needed to maintain tube integrity. Also, since the crack face area will be less than the total cross-sectional area used above, the difference in the force applied as a result of normal operating and accident condition pressures will be less than the 53.7 lbs calculated for the Model 51 steam generators. Therefore, the potential for ligament tearing is considered to be a secondary effect of essentially negligible probability and should not affect the results and conclusions reported for the W* evaluation. The leak rate model does not include provisions for predicting ligament tearing and subsequent leakage, and increasing the complexity of the model to attempt to account for ligament tearing has been demonstrated to be not necessary (Reference 6.4).

The potential for ligament tearing of postulated axial flaws can also be addressed qualitatively. The effects of postulated axial flaw ligament tearing within an expanded tubesheet condition would be addressed by the leakage testing which included drilled holes as the leakage path. Axial flaw ligament tearing within expanded tubesheet conditions cannot occur as the proximity of the tubesheet precludes tube diametrical expansion. Without the ability of the flaw to experience sufficient displacement at the crack tips tearing cannot occur. The Indication Restrained from Burst (IRB) testing performed in support of the voltage based repair criterion for axial ODSCC at drilled hole tube support plates per GL 95-05 has proven that for tube in the TSP configurations, which included approximately 20 mils of diametrical gap, that tearing at the crack tips does not occur. This same concept can be applied to partial depth flaws. Using the results from the original tubesheet deflection model for the Case 2 faulted condition, the diametrical gap between the tube and tubesheet at the top of cold leg tubesheet is less than 1 mil. This condition represents an insufficient amount of radial displacement for tearing to occur.

6.2.6 No Contact Length for Normal/Postulated Accident Conditions Discussion

The no contact length for each of the SG zones for both normal and postulated accident conditions is the axial length over which dilation of the tubesheet causes the mechanical interference fit contact pressure between the tube OD and the tubesheet hole surface to reduce to zero. The no contact length during normal operating conditions is less than 1.0 inch in Zones A and B. The no contact length during a postulated SLB is less than 3 inches in Zones A and B.

All WEXTEX expansions are assumed to have a small gap over the upper 0.7 inches of distance below the BWT for both pull out force and leakage analyses.

6.2.7 How do the yield strengths of tubes used in testing compare to plant values? (Wolf Creek RAI #1)

WCAP-14797, Rev 2, lists the yield strength of the tubes used for specimens W4-006 and W8-007A as 58 ksi. The mean yield and ultimate strength values of the 7/8 inch x 0.050 inch wall Alloy 600 MA tubing used by Westinghouse is 51 ksi and 100 ksi, respectively, with standard deviations of 4.2 and 3.4 ksi, respectively.

From Reference 6.4, the parameters which have the most influence upon contact pressure, in decreasing order of impact are the expansion process, tube yield strength, and tube to tubesheet radial clearance. Of lesser importance are the elastic modulus of the tube and tubesheet.

As the explosive expansion process involves deformation of the tube by a pressure wave, the higher the yield strength of the tubing, the lesser the remaining energy of the pressure to perform the tube expansion process. Thus the use of higher yield strength tubing in the test specimens will produce generally less contact pressure compared to the in situ tube population.

The tubesheet drilled hole dimensioning per the manufacturing drawing specifies the tube hole diameter as 0.888 to 0.893 inch. WCAP-14797, Rev 2, lists the ID of the collars used for W4-006 and W8-007A at 0.890. Specimen W8-007A was indicated to have been cut from a longer length specimen. Thus while the tube hole ID is within the tolerance range of hole diameters, the yield strength of the tubes was located at the upper end of the yield strength distribution.

WCAP-14797 Rev 2 includes pull test data for specimens NDE 01-01, NDE 01-02, NDE 02-01, and NDE 02-02. These specimens were intended for NDE purposes but were all pull tested. NDE 01-01 and NDE 01-02 were manufactured with oversized tube holes (0.894 to 0.895 inch). NDE 02-01 and NDE 02-02 were manufactured with slightly undersized holes (0.887 inch). These specimens contained combinations of axial and circumferential part through-wall EDM notches within the expansion length. As for specimens W4-006 and W8-007A the testing program included multiple tests at varying temperature conditions. For each test the tube was loaded to slip. The NDE specimen pull force results bound the results from the test used to define the process related residual contact pressure. It should be noted that specimen NDE 02-02 was stress relieved for 4 hours at 1100°F. The resistive load capability of NDE 02-02 was substantially larger than NDE 02-01.

6.2.8 How do dimensions of test specimens compare to actual plant values? (Wolf Creek RAI #2)

See response to 6.2.7.

6.2.9 How does pressure and thermal cycling affect pull out and leakage resistance? (Wolf Creek RAI #5)

Reference 6.4 presents results of leakage testing which shows that after the application of 29,000 tensile cycles that the leakage characteristics of the cycled specimens was essentially equal to the leakage characteristics of the specimens that were not cycled. These results are observed for tubes hydraulically expanded into the tubesheet, a process recognized to be less robust than the explosive expansion process.

With regard to pull out characteristics, WCAP-14797, Rev 2, provides discussion for the pull out tests specimens which indicates that the characteristic shape of the load-deflection curve during the load escalation phase was consistent and exhibited elastic characteristics to the slip point. Note that these specimens were successively tested to "first slip" four times. The specimens were loaded to first slip at room temperature, then at 400°F, 600°F, and 600°F with internal pressurization. The trending of the data shows for both specimens that the first slip load was increased with increasing temperature.

WCAP-14797, Rev 2, data includes one specimen (NDE 02-02) which was stress relieved at 1100°F. This modification was performed to simulate effects of the lower stub barrel to tubesheet weld post-weld heat treatment. It is unlikely that any tubes achieved a temperature of 1100°F as a result of this post-weld heat treatment. This specimen has the highest pull out resistive capability of all of the tested specimens.

6.2.10 Pull out resistance and Poisson contraction? (Wolf Creek RAI #6)

Reference 6.4 includes discussion which establishes that the use of pull out resistance is conservative. The force summation of the W* analysis does not include resistive load contribution over the first 1 inch of tube in tubesheet for normal operating conditions analysis. This is carried through the force summation even if the thermal and pressure growth indicates that contact would be provided in this region. Note that the proposed cold leg W* distance of 10.5 inches below the top of tubesheet includes approximately 3 inches of additional tube length which must be shown to be defect free compared to the value established by WCAP-14797 Rev 2.

6.2.11 Effects of Postulated Divider Plate Cracking (Wolf Creek RAI #25)

Section 4.4 discusses postulated divider plate cracking.

6.2.12 Sensitivity of the Calculated [star] Length to Variances in Material Properties Discussion. (Wolf Creek RAI #2, LTR-CDME-07-198)

Addressed by Section 4.3. TVA has elected to apply an arbitrary, conservative W* distance of 10.5 inches below the top of tubesheet for the cold leg tubes. This value is 3 inches greater than the value determined by WCAP-14797 Rev 2. The 10.5 inch cold leg W* is expected to bound the effects of material properties variances. Furthermore, as only one SG is postulated to become the faulted SG, the application of these sensitivities to the product of the number of SGs times the number of tubes per SG is incorrect.

6.2.13 Discuss the potential for slippage. (Wolf Creek RAI #8, LTR-CDME-07-198)

The response to RAI #8 of LTR-CDME-07-198 provides a detailed discussion of why slippage will not occur, but is specifically written based on hydraulically expanded tube data.

Postulated tube slippage is not considered a credible event based on the applied loads at normal operating condition considering that the existing W* analysis includes a factor of safety of 3 against postulated pull out. Any axial loading applied to the tubes not reacted at TSPs is by definition, no more than 1/3 of the analysis load. Standard eddy current data acquisition practice is to collect (and analyze) a conservative length of data to ensure that retesting is not required in order to achieve the appropriate test distance. Thus, each tube is functionally inspected to distances greater than required by the technical specification values.

The W* analysis is based on first slip reporting. All test data shows that steady, positive load escalation was observed with increasing displacement after first slip. In the unlikely event of joint slippage, the condition would be self limiting as the additional resistive load capability associated with galling and eventual interaction with tube hole geometry variances would prevent any further slippage.

The W* pull out specimens were loaded to slip multiple times; the resistive load trending shows no abnormalities. This is true for both specimens W4-006 and W8-007A as well as the NDE series specimens. The W* leakage testing included multiple tests of the same specimen. Again the trending shows no abnormalities. The temperature associated with the creep of Alloy 600 material is well above the hot leg operating temperature of pressurized water reactors (PWRs). If cyclic loading included the potential for the tube to experience small axial displacements it is believed that localized galling of tube and tubesheet surfaces would further restrict leakage. This is shown by test data included in Reference 6.5. In this program a proposed repair method using a double-hydraulic expansion sleeve design was investigated. The joint location was in the freespan region of the tubing. Leak test results performed prior to cyclic testing showed greater leakage than post cyclic testing.

6.3 STEAM LINE BREAK LEAKAGE CONSIDERATIONS

6.3.1 Validation of W* Leak Rate Model Through In Situ Testing (Callaway RAI # 63, St. Lucie 2 RAI # 19)

The following discussion is included for information only. The use of a bounding leak rate model based on test data for the SQN2 SG indications obviates the need to apply the standard W* leak rate model.

W* Leakage Model and In Situ Testing Validation Program

The W* leakage model was developed based upon first principles of leakage from a crack in a tight crevice. Leakage from a tight crevice is a series path through the crack with the crack opening constrained by the tubesheet, and followed by leakage through the tight crevice. In the leakage model, the total steam line break (SLB) pressure drop occurs from the tube inside diameter (ID) to near the top of the tubesheet (TTS) at the bottom of the WEXTEX transition (BWT). The crack inside the tubesheet, with very small clearances, cannot open significantly due to the constraint of the tubesheet hole ID. Leakage tests were performed to directly model this effect by measuring the leakage at the upper tip of the crack with small tube-to-tubesheet clearances. The leak rates for the constrained crack are correlated with contact pressure using an equivalent CRACKFLO crack length to represent leakage. Since the equivalent crack length is the length that gives the measured leak rate, the plot of Figure 6.4-1 of WCAP-14797, Rev 2, is essentially the leak rate through the crack at the crack tip versus contact pressure. The principal purpose in introducing the CRACKFLO equivalent length, rather than measured leakage, is to permit adjustments of the measured leak rates for the pressure drop across the crack in series with the crevice pressure drop for the leakage model.

The test data for leakage through the crevice is modeled using the crevice loss coefficient correlated with contact pressure. The loss coefficient is fit to each measured leak rate for the correlation with contact pressure, such that the correlation is essentially the leak rate through the crevice versus contact pressure. The use of a loss coefficient correlation, rather than leak rate, permits adjustments of the leak rate for the pressure drop across the crevice in series with the crack pressure drop.

Both the effective crack length and loss coefficient correlations are obtained as regression fits from the leak rate measurements. These values, therefore, are not analytical results. The analytical model is only used to perform the series leakage analysis, and consists primarily of adjustments to obtain equal leakage through the crack and crevice for the total tube ID to crevice exit pressure drop. This is a first principles fluid flow calculation based on prototypic, experimentally developed, effective lengths and loss coefficients. Combined crack and crevice leak tests by in situ testing were performed in 2R9 and 2R10 as described below.

To date, 14 W* indications have been in situ leak tested in the industry: Seven at Diablo Canyon Unit 2 (DCPP 2) at refueling outages 2R9 (1999) and 2R10 (2001), 1 at Sequoyah Unit 2 (SQN 2), and 6 at Beaver Valley Unit 1 (BVPS 1). The indications are listed in Table 6-2. No leakage was observed in any test. Most of the indications were located near the bottom of WEXTEX transition (BWT), such that the tubesheet provided minimal crevice restriction. The DCPP 2 indications are located in tubes that had been deplugged, were tested to normal operating pressure differential, and were returned to service. Non-deplugged W* indications at DCPP have not grown deep enough to satisfy the requirements for leak testing.

It is the TVA intent to only test in situ indications that meet the requirements of the EPRI In Situ Guidelines.

Table 6-2
Industry In Situ Test Results for Axial PWSCC in WEXTEX Region

Plant	Year	SG	Tube	Deplug tube	Crack distance below BWT, (below TTS for SQN and BVPS), inch	Peak Volt	Crack Length inch	Max Depth	Approx Length > 80%, inch	Test Pressure	Leak Rate
DCPP 2	1999	1	R3C59	Yes	0.51	5.6	0.27	100%	0.23	NOP	0
DCPP 2	1999	1	R7C62	Yes	0.59	4.2	0.35	80%	None	NOP	0
DCPP 2	1999	2	R31C25	Yes	0.98	4.0	0.24	70%	None	NOP	0
DCPP 2	2001	3	R7C52	Yes	0.56	3.4	0.43	94%	0.37	NOP	0
DCPP 2	2001	4	R3C5	Yes	0.55	1.5	0.83	100%	0.63	NOP	0
DCPP 2	2001	4	R2C29	Yes	3.52	4.5	0.91	100%	0.84	NOP	0
DCPP 2	2001	4	R2C29	Yes	1.83	0.9	0.34	100%	0.1	NOP	0
SQN 2	1997	4	R7C17	No	0.15	3.6	0.32	100%	0.02	3dpNO	0
BVPS 1	1997	A	R10C51	No	0.24	0.7	0.30	77%	None	3dpNO	0
BVPS 1	1997	A	R27C28	No	3.20	1.2	0.22	35%	None	3dpNO	0
BVPS 1	1997	B	R5C83	No	0.35	1.5	0.21	30%	None	3dpNO	0
BVPS 1	1997	C	R27C31	No	0.60	0.9	0.18	44%	None	3dpNO	(1)
BVPS 1	2001	A	R7 C59	No	1.86	1.98	----	33%	N/A	SLB ΔP	0
BVPS 1	2001	B	R35C22	No	1.51	1.3	----	50%	N/A	SLB ΔP	0

(1) In situ pressure testing tooling system leakage. No leakage judged to be due to a flaw.

W* in situ leak tests are conducted at the normal operation differential pressure. If the indication leaks, the test will be continued up to the SLB differential pressure, and the tube will be repaired. If leakage is not detected at the normal operation pressure difference, the test would be terminated without extending the pressure differential to SLB conditions. All tubes that are tested *in situ* are removed from service regardless of the test results.

Also, it is noted that in situ leak testing of likely through-wall indications near the top of the tubesheet does provide meaningful information relative to the potential for through-wall indications located deeper in the tubesheet to leak. The in situ testing experience has been such that indications do not leak. Because the hole dilation diminishes with distance into the tubesheet, there is a location with a post-accident condition radial contact load that corresponds to that achieved during the in situ testing. Thus, testing of through-wall indications near the top of the tubesheet supports the evaluations that conclude that leakage from tube indications deeper in the tubesheet would be negligible.

6.3.2 Discussion of Secondary to Primary Leakage Following Postulated LOCA (Diablo Canyon RAI # 3)

During normal operation, the tube-to-tubesheet contact pressure in the region above the tubesheet neutral bending axis is reduced by upward bending of the tubesheet due to the primary-to-secondary ΔP. This reduction in contact pressure is a function of elevation and radial location from the center of the tubesheet, and is accounted for in the determination of the W* lengths. During a postulated LOCA event, the primary side pressure drops to atmospheric conditions while the secondary side remains at 1005 psia. The component of the tube-to-tubesheet contact pressure resulting from primary pressure inside the tube is lost, and the external pressure on the tube acts to further reduce the tube-to-tubesheet contact pressure. However, the reversal of the ΔP across the tubesheet causes the tubesheet to bow downward, providing an increase in that component of the tube-to-tubesheet contact pressure above the neutral axis of the tubesheet. In the top four inches of the W* region near the top of the tubesheet, the increase in contact pressure due to downward tubesheet bending more than offsets the reduction in contact pressure due to the reversed ΔP across the tube wall. For instance, at a distance of 2 inches below the TTS, the tube-to-tubesheet contact pressure resulting from the primary-to-secondary ΔP is 790 psi during normal operation, while the maximum loss of contact pressure due to tubesheet bending is 1549.5 psi; the net minimum contact pressure (including an additional 509.8 psi contact pressure due to thermal expansion and 693 psi due to the residual WEXTEX contact pressure) is 443.3 psi. For postulated LOCA conditions, the loss of primary side pressure in conjunction with a secondary side pressure of 1005 psi results in a calculated contact pressure due to the secondary-to-primary ΔP of -1225.6 psi. However, tubesheet bow in the opposite direction adds 970.6 psi in addition to the 509.8 psi contact pressure due to thermal expansion and 693 psi from the WEXTEX expansion residual preload; the net minimum contact pressure is 947.8 psi, which is 504.5 psi greater than the contact pressure during normal operating conditions. The net effect is a tighter joint at the top of the tubesheet during a postulated LOCA event than exists during normal operating conditions. Past analyses performed by Westinghouse have shown that secondary-to-primary in-leakage through free span cracks occurs at a slower rate than primary-to-secondary leakage at the same ΔP. Based on this experience, along with the lower magnitude of the LOCA ΔP relative to that during normal operation, and with the increase of tube-to-tubesheet contact pressure at the TTS caused by the reverse tubesheet bow, in-leakage to the primary side during a LOCA event would be expected to occur at a slower rate than primary-to-secondary leakage during normal operation, which is limited to 150 gpd (0.1 gpm). In-leakage to the primary side through W* tubes during a LOCA event is therefore assured of occurring at a slower rate than 0.1 gpm and would therefore not affect the plant LOCA analyses (Reference 6.3).

6.3.3 Address How Leak Model Addresses 360° Circumferential Crack (Callaway RAI # 17, 26, 31 and 37)

The bounding leak rate model is directly based on the test data from effectively severed tubes and thus obviates the concern that led to the original RAIs. The prediction of leak rates is discussed in Section 4.0 of this report. The leak rate from a 360° crack between at the W* distance and 12 inches below the top of the tubesheet at the worst case radial location within the tubesheet is calculated to be 0.0045 gpm at 90% prediction interval. For assumed indications located greater than 12 inches below the top of the tubesheet, the bounding per tube leakage allowance is $9 \cdot 10^{-5}$ gpm. Modeling of future leak rates is a function of the number of predicted circumferentially oriented cracks in the SGs within the 8 to 12 and greater than 12 inches below top of tubesheet elevations.

6.3.4 Evaluation of Axial PWSCC within W* Distance (St. Lucie RAI # 17 and Callaway RAI # 72)

SLB Conditions Leakage Potential from Axial PWSCC within W*

At the BVPS 1R15 outage, 18 axial PWSCC indications on 18 tubes were reported. These indications ranged in elevation from 0.18 inch below TTS to 9.79 inch below TTS. The breakdown of indications per SG was; SGA, 3, SGB, 5, SGC, 10. Ten (10) of these 18 indications were noted within 1 inch of the TTS, and are assumed to be located within the expansion transition. The largest amplitude signal of 1.89 volts by +Pt was noted on tube R20 C36, SGA. Based on a +Pt amplitude versus depth correlation developed by Westinghouse, the maximum depth of this indication is estimated at 71%TW. The phase based depth analysis indicated a maximum depth of 97%TW. This flaw was located at 0.43 inch below TTS, which locates it within the expansion transition, and this elevation report is also consistent with the measured BWT. As this indication was located so close to the TTS, if it truly contained 100%TW penetration, leakage would be expected. The flaw length from profiling was 0.31 inch. This indication was in situ pressure tested to 2841 psi with no leakage and no burst reported at 4900 psi. FENOC has conservatively performed in situ pressure testing at previous outages of other axial PWSCC indications located within the W* distance. At the 1R14 outage (2001), a 1.98 volt axial PWSCC indication located at 1.86 inch below TTS was in situ pressure tested with no leakage or burst reported. At Diablo Canyon, axial PWSCC indications with amplitudes up to 5.6 volts by +Pt have been in situ pressure tested with no leakage or burst reported. At 5.6 volts, this indication is judged to have contained a 100%TW penetration. No less than 5 of the in situ pressure tested indications at Diablo Canyon are judged to have contained a 100%TW penetration based on +Pt amplitude. None leaked during in situ pressure test.

Other industry in situ pressure test data supports the application of the voltage based sizing technique. During the Fall 2003 inspection at a plant with C-E SGs, a 1.9 volt by +Pt, 106° arc length circumferential PWSCC indication was reported at the top of tubesheet. The phase based depth assessment indicated that the maximum depth of 99%TW extended for nearly the entire flawed length. This indication was in situ pressure tested for leakage only. No leakage was reported at 2900 psi. It should be noted that the depth estimate using the amplitude correlation is approximately 73%. In conclusion, in situ pressure testing of PWSCC indications at or below TTS has shown no leakage potential for indications up to 5.6 volts by +Pt.

Growth of Non-Detected or New Initiates During Operation

A history review of each of the BVPS 1R15 indications was performed using the 1R14 +Pt inspection data. Thirteen (13) of the 18, 1R15 flaws had a precursor signal in the 1R14 data. Of the five 1R15 indications with no precursor signal in 1R14, only one had an amplitude >1V. This indication was found at 0.49 inch below TTS, placing it within the expansion transition.

The only indication with a modest amplitude growth was R20 C36, which had an amplitude growth of 1.38 volts. As this indication was located within the expansion transition, the higher residual stresses of the transition would be expected to exacerbate growth. R20 C36 also had the largest length growth of 0.14 inch, and also had the only substantial depth growth (by phase) of 59%. Cycle 15 growth data is provided in Table 6-3. The Cycle 14 growth statistics are essentially equal to the Cycle 15 growth statistics. The only appreciable difference between the growth data for Cycles 15 and 14 is maximum depth growth. The expansion transition flaws appear to have a slightly higher maximum depth growth. The average +Pt voltage growth of 0.31 volts is modest for PWSCC as PWSCC amplitudes are greater than ODSCC for equal depths. The average length growth of 0.01" suggests that the residual stress fields that initiate the PWSCC are limited in length and do not represent a potential for indications with significant lengths.

The average +Pt voltage of the 1R14 precursor signals was 0.52 volts, suggesting that the detection threshold for axial PWSCC is slightly above this value. With a maximum +Pt voltage growth for Cycle 15 of 1.38, the maximum EOC16 PWSCC amplitude expected is approximately 2V. Based on the correlation of +Pt voltage to maximum depth, this postulated indication (2V amplitude) would be expected to have a maximum depth of about 74%TW. Therefore, axial PWSCC within the W* distance that either is initiated during the cycle or remains in service based on probability of detection is judged to result in an indication that is well <100%TW at the end of the next operating cycle, and will not contribute to primary to secondary leakage during a postulated SLB event. For the BVPS 1R16 outage, only 5 axial PWSCC indications were reported; no circumferential PWSCC was reported. The maximum +Pt amplitude was only 1.06 volts. Zinc injection was initiated just prior to the 1R15 outage. Cycle 16 involved zinc injection for the full cycle; the benefits are observed in the reduced indication count and reduced flaw amplitude responses for 1R16.

Indication Distribution

Approximately half of the total reported indications occur within 1 inch of the top of the tubesheet. A regression of all indication elevations and number of indications within a 1 inch elevation bin produces a best fit curve that predicts approximately 2 indications in the 8 to 9 inches below TTS bin, and approximately 1 indication per bin at 12 inches below TTS and lower. A regression was fit using all data with the exception of the data in the TTS to 1 inch below bin to determine if the initiation trend follows a similar pattern as for all data. The regression for this subset of data is essentially equal to the regression for all data. Thus, the judgment that the flaw initiation potential decreases with increasing depth below TTS remains valid for this data. Figure 4-5 presents the plot of all data and below expansion transition data as a function of depth below TTS. Note that the 90% probability prediction interval for all data bounds the data, particularly at the deeper elevations (Figure 5-8).

Table 6-3
BVPS Unit 1 (original SGs) Cycle 15 Tubesheet Region PWSCC Flaw Summary and Growth Evaluation

a,c,e

REFERENCES

6.1 NSD-E-SGDA-98-017, "RAI for Application of W* Tube Repair Criteria at Diablo Canyon," 1/26/98

6.2 WCAP-14201 (Proprietary), "Presentation Materials for September 12, 1994 US NRC/Wisconsin Electric/Westinghouse Meeting on Indications Within the Upper Joint Zone of Hybrid Expansion Joint (HEJ) Sleeved Tubes," Westinghouse Electric Company, Nuclear Services Division, Madison, PA, (October 1994)

6.3 CN-SGDA-04-52, "W* Ligament Tearing for Model 51 Steam Generators at Beaver Valley Unit 1," 5/19/04

6.4 LTR-CDME-07-72, "Response to NRC Request for Additional Information Relating to LTR-CDME-05-209-P of the Wolf Creek Generating Station (WCGS) Permanent B* License Amendment Request," Westinghouse Electric Company, Nuclear Services Division, Madison, PA, (April 2007)

6.5 CEN-617-P Rev 1, "Steam Generator Tube Repair for Tubes Containing Westinghouse Mechanical Sleeves Using Leak Limiting I690 Sleeves," Combustion Engineering, Inc., March 1995

6.6 NSD-E-SGDA-98-260, Rev. 1, "Response to NRC RAIs on Diablo Canyon W*", 8/20/98

ATTACHMENT 5

TENNESSEE VALLEY AUTHORITY
SEQUOYAH NUCLEAR PLANT (SQN)
UNITS 1 AND 2

Westinghouse Proprietary Data Withholding Affidavit No. CAW-09-2548

Westinghouse Electric Company
Nuclear Services
P.O. Box 355
Pittsburgh, Pennsylvania 15230-0355
USA

U.S. Nuclear Regulatory Commission
Document Control Desk
Washington, DC 20555-0001

Direct tel: (412) 374-4643
Direct fax: (412) 374-4011
e-mail: greshaja@westinghouse.com

Our ref: CAW-09-2548

March 25, 2009

APPLICATION FOR WITHHOLDING PROPRIETARY
INFORMATION FROM PUBLIC DISCLOSURE

Subject: LTR-SGMP-09-35-P-Attachment, "Application of W* Alternate Repair Criteria to Sequoyah Unit 2 Cold Leg Tubes (Proprietary)

The proprietary information for which withholding is being requested in the above-referenced report is further identified in Affidavit CAW-09-2548 signed by the owner of the proprietary information, Westinghouse Electric Company LLC. The affidavit, which accompanies this letter, sets forth the basis on which the information may be withheld from public disclosure by the Commission and addresses with specificity the considerations listed in paragraph (b)(4) of 10 CFR Section 2.390 of the Commission's regulations.

Accordingly, this letter authorizes the utilization of the accompanying affidavit by Tennessee Valley Authority.

Correspondence with respect to the proprietary aspects of the application for withholding or the Westinghouse affidavit should reference this letter, CAW-09-2548, and should be addressed to J. A. Gresham, Manager, Regulatory Compliance and Plant Licensing, Westinghouse Electric Company LLC, P.O. Box 355, Pittsburgh, Pennsylvania 15230-0355.

Very truly yours,

J.A. Gresham

J.A. Gresham, Manager
Regulatory Compliance and Plant Licensing

Enclosures

cc: George Bacuta (NRC- OWFN 12E-1)

bcc: J. A. Gresham (ECE 4-7A) 1L
R. Bastien, 1L (Nivelles, Belgium)
C. Brinkman, 1L (Westinghouse Electric Co., 12300 Twinbrook Parkway, Suite 330, Rockville, MD 20852)
RCPL Administrative Aide (ECE 4-7A) 1L (letter and affidavit only)
W.K. Cullen, Waltz Mill
D.A. Testa, Waltz Mill
D.D. Malinowski, Waltz Mill
G.W. Whiteman, Waltz Mill
P.M. McHale, ECE 557H

AFFIDAVIT

COMMONWEALTH OF PENNSYLVANIA:

ss

COUNTY OF ALLEGHENY:

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

J A Gresham

J. A. Gresham, Manager
Regulatory Compliance and Plant Licensing

Sworn to and subscribed before me
this 25th day of March, 2009

Lorraine M. Piplica

Notary Public

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Lorraine M. Piplica, Notary Public
Monroeville Boro, Allegheny County
My Commission Expires Dec. 14, 2011
Member, Pennsylvania Association of Notaries

(1) I am Manager, Regulatory Compliance and Plant Licensing, in Nuclear Services, Westinghouse Electric Company LLC (Westinghouse), and as such, I have been specifically delegated the function of reviewing the proprietary information sought to be withheld from public disclosure in connection with nuclear power plant licensing and rule making proceedings, and am authorized to apply for its withholding on behalf of Westinghouse.

(2) I am making this Affidavit in conformance with the provisions of 10 CFR Section 2.390 of the Commission's regulations and in conjunction with the Westinghouse "Application for Withholding" accompanying this Affidavit.

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

(4) Pursuant to the provisions of paragraph (b)(4) of Section 2.390 of the Commission's regulations, the following is furnished for consideration by the Commission in determining whether the information sought to be withheld from public disclosure should be withheld.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(iii) The information is being transmitted to the Commission in confidence and, under the provisions of 10 CFR Section 2.390, it is to be received in confidence by the Commission.

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

(v) The proprietary information sought to be withheld in this submittal is that which is appropriately marked in LTR-SGMP-09-35-P-Attachment, "Application of W* Alternate Repair Criteria to Sequoyah Unit 2 Cold Leg Tubes," dated March 25, 2009 (Proprietary), for submittal to the Commission, being transmitted by Tennessee Valley Authority Application for Withholding Proprietary Information from Public Disclosure to the Document Control Desk. The proprietary information as submitted for use by Westinghouse for Sequoyah Unit 2 is expected to be applicable to other licensee submittals in support of implementing an alternate repair criterion (ARC) that requires a full-length inspection of the tubes within the tubesheet but does not require plugging tubes within a certain distance from the top of the tubesheet.

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

(a) Provide documentation of the analyses, methods, and testing for the implementation of an alternate repair criterion for the portion if the tubes within the tubesheet of the Sequoyah Unit 2 steam generators.

(b) Assist the customer in obtaining NRC approval of the Technical Specification changes associated with the alternate repair criterion.

Further this information has substantial commercial value as follows:

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

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

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

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

In order for competitors of Westinghouse to duplicate this information, similar technical programs would have to be performed and a significant manpower effort, having the requisite talent and experience, would have to be expended.

Further the deponent sayeth not.

PROPRIETARY INFORMATION NOTICE

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

In order to conform to the requirements of 10 CFR 2.390 of the Commission's regulations concerning the protection of proprietary information so submitted to the NRC, the information which is proprietary in the proprietary versions is contained within brackets, and where the proprietary information has been deleted in the non-proprietary versions, only the brackets remain (the information that was contained within the brackets in the proprietary versions having been deleted). The justification for claiming the information so designated as proprietary is indicated in both versions by means of lower case letters (a) through (f) located as a superscript immediately following the brackets enclosing each item of information being identified as proprietary or in the margin opposite such information. These lower case letters refer to the types of information Westinghouse customarily holds in confidence identified in Sections (4)(ii)(a) through (4)(ii)(f) of the affidavit accompanying this transmittal pursuant to 10 CFR 2.390(b)(1).

COPYRIGHT NOTICE