VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

September 30, 2009

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U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
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Serial No. 09-455B
SPS/LIC/CGL R2
Docket Nos. 50-280/281
License Nos. DPR-32/37

VIRGINIA ELECTRIC AND POWER COMPANY (DOMINION)
SURRY POWER STATION UNITS 1 AND 2
PROPOSED LICENSE AMENDMENT REQUEST
ONE-TIME ALTERNATE REPAIR CRITERIA
FOR STEAM GENERATOR TUBE INSPECTION/REPAIR FOR UNITS 1 AND 2

A July 28, 2009 Dominion letter (Serial No. 09-455) requested a license amendment to revise the Surry Power Station Units 1 and 2 Technical Specifications (TS). The proposed change requested revision of the inspection scope and repair requirements of TS 6.4.Q, "Steam Generator (SG) Program," and the reporting requirements of TS 6.6.A.3, "Steam Generator Tube Inspection Report." The proposed change requested approval of permanent alternate repair criteria (PARC) to exclude portions of the tube below the top of the steam generator tube sheet from periodic steam generator tube inspections. Westinghouse WCAP-17092-P, Revision 0, "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model 51F)," was included as Attachment 5 in the July 28, 2009 letter and provides the basis for the proposed change. The license amendment request (LAR) also included proposed revisions to TS 3.1.C and TS 4.13, which are both titled "RCS Operational Leakage," to delete a primary to secondary leakage limitation that was included as part of the modified interim alternate repair criteria previously approved for the Surry Unit 1 B SG. Associated revisions to the Bases for TS 3.1.C and TS 4.13 were also included for the NRC's information.

On August 14, 2009, an NRC request for additional information (RAI) was communicated to Dominion regarding the Model 51F Westinghouse WCAP-17092-P and the Surry PARC LAR transmitted by the July 28, 2009 letter. Dominion provided the response to the RAI by a September 16, 2009 letter (Serial No. 09-455A).

On September 2, 2009, during a teleconference between NRC and industry personnel, the NRC Staff indicated that Staff concerns with eccentricity of the tube sheet tube bore in normal and accident conditions (RAI Question 4) have not been adequately resolved to justify a permanent, generic application of the WCAP. The Staff further indicated that there was insufficient time to resolve their concerns to support approval of the permanent amendment request for plants with fall 2009 refueling outages. As such, Dominion is proposing to revise the proposed permanent change contained in the July 28, 2009 LAR to be a one-time change to TS 4.13, TS 6.4.Q and TS 6.6.A.3 for Surry Unit 2 during the fall 2009 Refueling Outage 22 and the subsequent operating

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cycle and to TS 3.1.C, TS 4.13, TS 6.4.Q and TS 6.6.A.3 for Unit 1 during the fall 2010 Refueling Outage 23 and the subsequent operating cycle. The justification for this one time alternate repair criteria license amendment using the permanent H* value is provided in Attachment 1. The marked-up TS and Bases pages are provided in Attachment 2, and the proposed TS and Bases pages are provided in Attachments 3 and 4 for Surry Units 2 and 1, respectively, due to their differing implementation dates.

The requested one-time change does not expand the scope of the request originally transmitted. The one-time change also does not affect the conclusion of the no significant hazards consideration discussion provided in our July 28, 2009 letter and as published by the NRC in the Federal Register (Accession No. ML092020471).

Dominion requests approval of the proposed license amendments contained herein by October 16, 2009 with a 30-day implementation period to support the Surry Unit 2 Refueling Outage (fall 2009). The one-time change will be implemented on Unit 2 prior to the startup following the fall 2009 Unit 2 Refueling Outage 22 and on Unit 1 prior to the startup following the fall 2010 Unit 1 Refueling Outage 23.

Dominion also requests that the NRC Staff provide the specific questions remaining to be resolved with respect to the eccentricity of the tube sheet tube bore in normal and accident conditions (RAI Question 4) and that the review of the permanent alternate repair criteria license amendment request continue.

If you have any questions or require additional information, please contact Mr. Gary D. Miller at (804) 273-2771.

Sincerely,

J. Alan Price
Vice President – Nuclear Engineering

COMMONWEALTH OF VIRGINIA)
)
COUNTY OF HENRICO)

The foregoing document was acknowledged before me, in and for the County and Commonwealth aforesaid, today by J. Alan Price, who is Vice President – Nuclear Engineering, of Virginia Electric and Power Company. He has affirmed before me that he is duly authorized to execute and file the foregoing document in behalf of that Company, and that the statements in the document are true to the best of his knowledge and belief.

Acknowledged before me this 30th day of September, 2009.

My Commission Expires: January 31, 2012

Notary Public

Reg # 341589

Commitments made in this letter: See Attachment 5 – List of Regulatory Commitments

Attachments:
1. Justification for One-Time Alternate Repair Criteria Using the Permanent H* Value
2. Marked-up of Technical Specifications and Bases Pages
3. Proposed Unit 2 Technical Specifications Pages (Implement Fall 2009)
4. Proposed Unit 1 Technical Specifications and Bases Pages (Implement Fall 2010)
5. List of Regulatory Commitments

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ATTACHMENT 1

JUSTIFICATION FOR ONE-TIME ALTERNATE REPAIR CRITERIA USING THE PERMANENT H* VALUE

VIRGINIA ELECTRIC AND POWER COMPANY
(DOMINION)
SURRY POWER STATION UNITS 1 AND 2

JUSTIFICATION FOR ONE-TIME ALTERNATE REPAIR CRITERIA USING THE PERMANENT H* VALUE

The permanent H* submittal in Dominion's July 28, 2009 letter (Serial No. 09-455) is based on maintaining structural and leakage integrity in the event of an accident.

From a structural perspective, the 16.7 inch value of H* ensures that tube rupture or tube pull out from the tube sheet will not occur in the event of an accident over the life of the plant. Even in the event that all tubes in the steam generator have a 360 degree sever at 16.7 inches, structural integrity of the steam generator tube bundle will be maintained. This assumption bounds the current status of the Surry Units 1 and 2 steam generators with significant margin.

At Surry, tube flaw indications within the tube sheet have only been found at the hot leg tube ends. Approximately 24,725 tube ends have been recently inspected at Surry. Two hundred sixteen (216) flaw indications have been reported. These indications were located within 1 inch of the tube end and are associated with residual stress conditions at the tube ends. Twelve (12) tubes in Unit 1 and six (6) tubes in Unit 2 were plugged for tube end cracks.

In addition, over 50% of the overexpansion/bulge indications within the tubesheet have been inspected in both Unit 1 and Unit 2 with no degradation found.

Based on these inspections, no indications of a 360 degree sever have been detected in any steam generator at Surry. Consequently, the level of degradation in the Surry steam generators is very limited compared to the assumption of "all tubes severed" that was utilized in the development of the permanent H* value. Thus, structural integrity will be assured for this one-time interim alternate repair criteria for the operating period between inspections allowed by TS 6.4.Q, "Steam Generator (SG) Program."

From a leakage perspective, projections of accident induced steam generator tube leakage are based on leakage rate factors applied to leakage detected during normal operation. The multiplication factor used for Surry bounds the expected increased leakage in the event of an accident at Surry. The projected accident induced leakage remains the same for both this one-time request and the permanent H* amendment request. No primary to secondary steam generator tube leakage has been detected during the current operating cycles at Surry.

For Surry, the number of tubes identified with flaws within the tubesheet is small in comparison to the input assumptions used in the development of the permanent H* value. Consequently, significant margin exists between the current state of the Surry steam generators and the conservative assumptions used as the basis for the permanent H* value. Structural and leakage integrity will continue to be assured for the operating period between inspections allowed by TS 6.4.Q, "Steam Generator (SG) Program," with the implementation of this proposed one-time alternate repair criteria using the permanent H* value.

ATTACHMENT 2

MARKED-UP TECHNICAL SPECIFICATIONS AND BASES PAGES

VIRGINIA ELECTRIC AND POWER COMPANY
(DOMINION)
SURRY POWER STATION UNITS 1 AND 2

C. RCS Operational LEAKAGE

Applicability

The following specifications are applicable to RCS operational LEAKAGE whenever Tavg (average RCS temperature) exceeds 200°F (200 degrees Fahrenheit).

Specifications

1. RCS operational LEAKAGE shall be limited to:

a. No pressure boundary LEAKAGE,

b. 1 gpm unidentified LEAKAGE,

c. 10 gpm identified LEAKAGE, and

d. 150 gallons per day primary to secondary LEAKAGE through any one steam generator (SG)~~, with the following exception. The primary to secondary LEAKAGE for the Unit 1 B steam generator will be limited to 20 gallons per day during Operating Cycle 23.~~

2.a. If RCS operational LEAKAGE is not within the limits of 3.1.C.1 for reasons other than pressure boundary LEAKAGE or primary to secondary LEAKAGE, reduce LEAKAGE to within the specified limits within 4 hours.

b. If the LEAKAGE is not reduced to within the specified limits within 4 hours, the unit shall be brought to HOT SHUTDOWN within the next 6 hours and COLD SHUTDOWN within the following 30 hours.

3. If RCS pressure boundary LEAKAGE exists, or primary to secondary LEAKAGE is not within the limit specified in 3.1.C.1.d, the unit shall be brought to HOT SHUTDOWN within 6 hours and COLD SHUTDOWN within the following 30 hours.

This LCO deals with protection of the reactor coolant pressure boundary (RCPB) from degradation and the core from inadequate cooling, in addition to preventing the accident analyses radiation release assumptions from being exceeded. The consequences of violating this LCO include the possibility of a loss of coolant accident (LOCA).

APPLICABLE SAFETY ANALYSES - Except for primary to secondary LEAKAGE, the safety analyses do not address operational LEAKAGE. However, other operational LEAKAGE is related to the safety analyses for LOCA; the amount of leakage can affect the probability of such an event. The safety analysis for an event resulting in steam discharge to the atmosphere assumes that primary to secondary LEAKAGE from all steam generators (SGs) is 1 gpm or increases to 1 gpm as a result of accident induced conditions. The LCO requirement to limit primary to secondary LEAKAGE through any one SG to less than or equal to 150 gallons per day is significantly less than the conditions assumed in the safety analysis. ~~Due to the permeability variation indications in the Unit 1B steam generator found during Refueling Outage 22, the primary to secondary leak rate for that steam generator is limited to 20 gallons per day for Operating Cycle 23.~~

Primary to secondary LEAKAGE is a factor in the dose releases outside containment resulting from a main steam line break (MSLB) accident. Other accidents or transients involve secondary steam release to the atmosphere, such as a steam generator tube rupture (SGTR). The leakage contaminates the secondary fluid.

The UFSAR (Ref. 2) analysis for SGTR assumes the contaminated secondary fluid is released via power operated relief valves or safety valves. The source term in the primary system coolant is transported to the affected (ruptured) steam generator by the break flow. The affected steam generator discharges steam to the environment for 30 minutes until the generator is manually isolated. The 1 gpm primary to secondary LEAKAGE transports the source term to the unaffected steam generators. Releases continue through the unaffected steam generators until the Residual Heat Removal System is placed in service.

The MSLB is less limiting for site radiation releases than the SGTR. The safety analysis for the MSLB accident assumes 1 gpm total primary to secondary LEAKAGE, including 500 gpd leakage into the faulted generator. The dose consequences resulting from the MSLB and the SGTR accidents are within the limits defined in the plant licensing basis.

The RCS operational LEAKAGE satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LIMITING CONDITIONS FOR OPERATION - RCS operational LEAKAGE shall be limited to:

a. Pressure Boundary LEAKAGE

No pressure boundary LEAKAGE is allowed, being indicative of material deterioration. LEAKAGE of this type is unacceptable as the leak itself could cause further deterioration, resulting in higher LEAKAGE. Violation of this LCO could result in continued degradation of the RCPB. LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE.

b. Unidentified LEAKAGE

One gallon per minute (gpm) of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the containment air monitoring and containment sump level monitoring equipment can detect within a reasonable time period. Violation of this LCO could result in continued degradation of the RCPB, if the LEAKAGE is from the pressure boundary.

c. Identified LEAKAGE

Up to 10 gpm of identified LEAKAGE is considered allowable because LEAKAGE is from known sources that do not interfere with detection of unidentified LEAKAGE and is well within the capability of the RCS Makeup System. Identified LEAKAGE includes LEAKAGE to the containment from specifically known and located sources, but does not include pressure boundary LEAKAGE or controlled reactor coolant pump (RCP) seal leakoff (a normal function not considered LEAKAGE). Violation of this LCO could result in continued degradation of a component or system.

d. Primary to Secondary LEAKAGE through Any One SG

The limit of 150 gallons per day per SG is based on the operational LEAKAGE performance criterion in NEI 97-06, Steam Generator Program Guidelines (Ref. 3). The Steam Generator Program operational LEAKAGE performance criterion in NEI 97-06 states, "The RCS operational primary to secondary leakage through any one SG shall be limited to 150 gallons per day." The limit is based on operating experience with SG tube degradation mechanisms that result in tube leakage. The operational leakage rate criterion in conjunction with the implementation of the Steam Generator Program is an effective measure for minimizing the frequency of steam generator tube ruptures. ~~Due to the permeability variation indications in the Unit 1 B steam generator found during Refueling Outage 22, the primary to secondary leak rate for that steam generator is limited to 20 gallons per day for Operating Cycle 23.~~

APPLICABILITY - In REACTOR OPERATION conditions where T_{avg} exceeds 200°F, the potential for RCPB LEAKAGE is greatest when the RCS is pressurized.

In COLD SHUTDOWN and REFUELING SHUTDOWN, LEAKAGE limits are not required because the reactor coolant pressure is far lower, resulting in lower stresses and reduced potentials for LEAKAGE.

LCO 3.1.C.5 measures leakage through each individual pressure isolation valve (PIV) and can impact this LCO. Of the two PIVs in series in each isolated line, leakage measured through one PIV does not result in RCS LEAKAGE when the other is leaktight. If both valves leak and result in a loss of mass from the RCS, the loss must be included in the allowable identified LEAKAGE.

4.13 RCS OPERATIONAL LEAKAGE

Applicability

The following specifications are applicable to RCS operational LEAKAGE whenever T_{avg} (average RCS temperature) exceeds 200°F (200 degrees Fahrenheit).

Objective

To verify that RCS operational LEAKAGE is maintained within the allowable limits.

Specifications

A. Verify RCS operational LEAKAGE is within the limits specified in TS 3.1.C by performance of RCS water inventory balance once every 24 hours[1,2]

B. Verify primary to secondary LEAKAGE is ≤ 150 gallons per day through any one SG once every 72 hours[1]~~, with the following exception. The primary to secondary LEAKAGE for the Unit 1 B steam generator will be verified to be ≤ 20 gallons per day during Operating Cycle 23.~~ If it is not practical to assign the LEAKAGE to an individual SG, all the primary to secondary LEAKAGE should be conservatively assumed to be from one SG.

Notes:

1. Not required to be completed until 12 hours after establishment of steady state operation.

2. Not applicable to primary to secondary LEAKAGE.

BASES

SURVEILLANCE REQUIREMENTS (SR)

SR 4.13.A

Verifying RCS LEAKAGE to be within the Limiting Condition for Operation (LCO) limits ensures the integrity of the reactor coolant pressure boundary (RCPB) is maintained. Pressure boundary LEAKAGE would at first appear as unidentified LEAKAGE and can only be positively identified by inspection. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. Unidentified LEAKAGE and identified LEAKAGE are determined by performance of an RCS water inventory balance.

The RCS water inventory balance must be performed with the reactor at steady state operating conditions (stable pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows). The surveillance is modified by two notes. Note 1 states that this SR is not required to be completed until 12 hours after establishing steady state operation. The 12 hour allowance provides sufficient time to collect and process all necessary data after stable unit conditions are established.

Steady state operation is required to perform a proper inventory balance since calculations during maneuvering are not useful. For RCS operational LEAKAGE determination by water inventory balance, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows.

An early warning of pressure boundary LEAKAGE or unidentified LEAKAGE is provided by the automatic systems that monitor the containment atmosphere radioactivity and the containment sump level. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. These leakage detection systems are specified in the TS 3.1.C Bases.

Note 2 states that this SR is not applicable to primary to secondary LEAKAGE because LEAKAGE of 150 gallons per day cannot be measured accurately by an RCS water inventory balance.

The 24 hour frequency is a reasonable interval to trend LEAKAGE and recognizes the importance of early leakage detection in the prevention of accidents.

SR 4.13.B

This SR verifies that primary to secondary LEAKAGE is less than or equal to 150 gallons per day through any one SG~~, with the following exception. The primary to secondary LEAKAGE for the Unit 1 B steam generator will be limited to 20 gallons per day during Operating Cycle 23.~~ Satisfying the primary to secondary LEAKAGE limit ensures that the operational LEAKAGE performance criterion in the Steam Generator Program is met. If this SR is not met, compliance with LCO 3.1.H, "Steam Generator Tube Integrity," should be evaluated. The 150 gallons per day limit is measured at room temperature as described in Reference 4. The operational LEAKAGE rate limit applies to LEAKAGE through any one SG.

If it is not practical to assign the LEAKAGE to an individual SG, all the primary to secondary LEAKAGE should be conservatively assumed to be from one SG~~; for Unit 1 that leakage should be assumed to be through the B steam generator for Operating Cycle 23.~~ The surveillance is modified by a Note, which states that the Surveillance is not required to be performed until 12 hours after establishment of steady state operation. For RCS primary to secondary LEAKAGE determination, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows.

The surveillance frequency of 72 hours is a reasonable interval to trend primary to secondary LEAKAGE and recognizes the importance of early leakage detection in the prevention of accidents. The primary to secondary LEAKAGE is determined using continuous process radiation monitors or radiochemical grab sampling in accordance with the EPRI guidelines (Ref. 4).

c. The operational LEAKAGE performance criterion is specified in TS 3.1.C and 4.13, "RCS Operational LEAKAGE."

3. Provisions for SG tube repair criteria. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged.

The following alternate tube repair criteria shall be applied as an alternative to the 40% depth-based criteria:

INSERT 1

~~a. For Unit 2 Refueling Outage 21 and the subsequent operating cycle, tubes with flaws having a circumferential component less than or equal to 203 degrees found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet do not require plugging. Tubes with flaws having a circumferential component greater than 203 degrees found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet shall be removed from service.~~

~~Tubes with service-induced flaws located within the region from the top of the tubesheet to 17 inches below the top of the tubesheet shall be removed from service. Tubes with service-induced axial cracks found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging.~~

~~When more than one flaw with circumferential components is found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet with the total of the circumferential components greater than 203 degrees and an axial separation distance of less than 1 inch, then the tube shall be removed from service. When the circumferential components of each of the flaws are added, it is acceptable to count the overlapped portions only once in the total of circumferential components.~~

~~When one or more flaws with circumferential components are found in the portion of the tube within 1 inch from the bottom of the tubesheet, and the total of these circumferential components exceeds 94 degrees, then the tube shall be removed from service. When one or more flaws with circumferential components are found in the portion of the tube within 1 inch from the bottom of the tubesheet and within 1 inch axial separation distance of a flaw above 1 inch from the bottom of the tubesheet, and the total of these circumferential~~

INSERT 1

For Unit 2 during Refueling Outage 22 and the subsequent operating cycle and for Unit 1 during Refueling Outage 23 and the subsequent operating cycle, tubes with service-induced flaws located greater than 16.7 inches below the top of the tubesheet do not require plugging. Tubes with service-induced flaws located in the portion of the tube from the top of the tubesheet to 16.7 inches below the top of the tubesheet shall be plugged upon detection.

components exceeds 94 degrees, then the tube shall be removed from service. When the circumferential components of each of the flaws are added, it is acceptable to count the overlapped portions only once in the total of circumferential components.

b. For Unit 1 Refueling Outage 22 and the subsequent operating cycle, tubes with flaws having a circumferential component less than or equal to 203 degrees found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet do not require plugging. Tubes with flaws having a circumferential component greater than 203 degrees found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet shall be removed from service.

Tubes with service-induced flaws located within the region from the top of the tubesheet to 17 inches below the top of the tubesheet shall be removed from service. Tubes with service-induced axial cracks found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging.

When more than one flaw with circumferential components is found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet with the total of the circumferential components greater than 203 degrees and an axial separation distance of less than 1 inch, then the tube shall be removed from service. When the circumferential components of each of the flaws are added, it is acceptable to count the overlapped portions only once in the total of circumferential components.

When one or more flaws with circumferential components are found in the portion of the tube within 1 inch from the bottom of the tubesheet, and the total of these circumferential components exceeds 94 degrees, then the tube shall be removed from service. When one or more flaws with circumferential components are found in the portion of the tube within 1 inch from the bottom of the tubesheet and within 1 inch axial separation distance of a flaw above 1 inch from the bottom of the tubesheet, and the total of these circumferential components exceeds 94 degrees, then the tube shall be removed from service. When the circumferential components of each of the flaws are added, it is acceptable to count the overlapped portions only once in the total of circumferential components.

c. For Unit 1 Refueling Outage 22 and the subsequent operating cycle, tubes in the B steam generator with permeability variation indications that may mask flaws in the bottom one inch of the tubesheet do not require plugging.

4. 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 4.a, 4.b, and 4.c 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.

INSERT 2

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

   b. Inspect 100% of the tubes at sequential periods of 120, 90, and, thereafter, 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the SGs. In addition, inspect 50% of the tubes by the refueling outage nearest the midpoint of the period and the remaining 50% by the refueling outage nearest the end of the period. No SG shall operate for more than 48 effective full power months or two refueling outages (whichever is less) without being inspected.

   c. 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.

the portions of the SG tube not excluded above,

5. Provisions for monitoring operational primary to secondary LEAKAGE.

INSERT 2

For Unit 2 during Refueling Outage 22 and the subsequent operating cycle and for Unit 1 during Refueling Outage 23 and the subsequent operating cycle, portions of the tube greater than 16.7 inches below the top of the tubesheet are excluded from this requirement.

b. The results of specific activity analysis in which the primary coolant exceeded the limits of Specification 3.1.D.4. In addition, the information itemized in Specification 3.1.D.4 shall be included in this report.

3. Steam Generator Tube Inspection Report

A report shall be submitted within 180 days after T_{avg} exceeds 200°F following completion of an inspection performed in accordance with the Specification 6.4.Q, Steam Generator (SG) Program. The report shall include:

a. The scope of inspections performed on each SG,

b. Active degradation mechanisms found,

c. Nondestructive examination techniques utilized for each degradation mechanism,

d. Location, orientation (if linear), and measured sizes (if available) of service induced indications,

e. Number of tubes plugged during the inspection outage for each active degradation mechanism,

f. Total number and percentage of tubes plugged to date,

g. The results of condition monitoring, including the results of tube pulls and in-situ testing, ~~and~~

h. The effective plugging percentage for all plugging in each SG,

INSERT 3

i. ~~Following completion of a Unit 2 inspection performed in Refueling Outage 21 (and any inspections performed in the subsequent operating cycle), the number of indications and location, size, orientation, whether initiated on primary or secondary side for each service-induced flaw within the thickness of the tubesheet, and the total of the circumferential components and any circumferential overlap below 17 inches from the top of the tubesheet as determined in accordance with TS 6.4.Q.3.a,~~

INSERT 3

i. For Unit 2 during Refueling Outage 22 and the subsequent operating cycle and for Unit 1 during Refueling Outage 23 and the subsequent operating cycle, the primary to secondary LEAKAGE rate observed in each SG (if it is not practical to assign the LEAKAGE to an individual SG, the entire primary to secondary LEAKAGE should be conservatively assumed to be from one SG) during the cycle preceding the inspection which is the subject of the report, and
j. For Unit 2 during Refueling Outage 22 and the subsequent operating cycle and for Unit 1 during Refueling Outage 23 and the subsequent operating cycle, the calculated accident induced LEAKAGE rate from the portion of the tubes below 16.7 inches from the top of the tubesheet for the most limiting accident in the most limiting SG. In addition, if the calculated accident induced LEAKAGE rate from the most limiting accident is less than 2.03 times the maximum operational primary to secondary LEAKAGE rate, the report should describe how it was determined.
k. For Unit 2 during Refueling Outage 22 and the subsequent operating cycle and for Unit 1 during Refueling Outage 23 and the subsequent operating cycle, the results of the monitoring for tube axial displacement (slippage). If slippage is discovered, the implications of the discovery and corrective action shall be provided.

j. Following completion of a Unit 2 inspection performed in Refueling Outage 21 (and any inspections performed in the subsequent operating cycle), the primary to secondary LEAKAGE rate observed in each steam generator (if it is not practical to assign leakage to an individual SG, the entire primary to secondary LEAKAGE should be conservatively assumed to be from one steam generator) during the cycle preceding the inspection which is the subject of the report, and

k. Following completion of a Unit 2 inspection performed in Refueling Outage 21 (and any inspections performed in the subsequent operating cycle), the calculated accident leakage rate from the portion of the tube below 17 inches below the top of the tubesheet for the most limiting accident in the most limiting steam generator.

l. Following completion of a Unit 1 inspection performed in Refueling Outage 22 (and any inspections performed in the subsequent operating cycle), the number of indications and location, size, orientation, whether initiated on primary or secondary side for each service-induced flaw within the thickness of the tubesheet, and the total of the circumferential components and any circumferential overlap below 17 inches from the top of the tubesheet as determined in accordance with TS 6.4.Q.3,

m. Following completion of a Unit 1 inspection performed in Refueling Outage 22 (and any inspections performed in the subsequent operating cycle), the primary to secondary LEAKAGE rate observed in each steam generator (if it is not practical to assign leakage to an individual SG, the entire primary to secondary LEAKAGE should be conservatively assumed to be from one steam generator) during the cycle preceding the inspection which is the subject of the report,

n. Following completion of a Unit 1 inspection performed in Refueling Outage 22 (and any inspections performed in the subsequent operating cycle), the calculated accident leakage rate from the portion of the tube 17 inches below the top of the tubesheet for the most limiting accident in the most limiting steam generator, and

o. ~~Following completion of a Unit 1 inspection performed in Refueling Outage 22 (and any other inspections performed in the subsequent operating cycle), for the B steam generator, the number of permeability variation indications including location and total circumferential extent.~~

ATTACHMENT 3

PROPOSED UNIT 2 TECHNICAL SPECIFICATIONS PAGES (IMPLEMENT FALL 2009)

**VIRGINIA ELECTRIC AND POWER COMPANY
(DOMINION)
SURRY POWER STATION UNITS 1 AND 2**

4.13 RCS OPERATIONAL LEAKAGE

Applicability

The following specifications are applicable to RCS operational LEAKAGE whenever T_{avg} (average RCS temperature) exceeds 200°F (200 degrees Fahrenheit).

Objective

To verify that RCS operational LEAKAGE is maintained within the allowable limits.

Specifications

A. Verify RCS operational LEAKAGE is within the limits specified in TS 3.1.C by performance of RCS water inventory balance once every 24 hours[1, 2]

B. Verify primary to secondary LEAKAGE is ≤ 150 gallons per day through any one SG once every 72 hours, with the following exception. The primary to secondary LEAKAGE for the Unit 1 B steam generator will be verified to be ≤ 20 gallons per day during Operating Cycle 23.[1] If it is not practical to assign the LEAKAGE to an individual SG, all the primary to secondary LEAKAGE should be conservatively assumed to be from one SG.

Notes:

1. Not required to be completed until 12 hours after establishment of steady state operation.
2. Not applicable to primary to secondary LEAKAGE.

BASES

SURVEILLANCE REQUIREMENTS (SR)

SR 4.13.A

Verifying RCS LEAKAGE to be within the Limiting Condition for Operation (LCO) limits ensures the integrity of the reactor coolant pressure boundary (RCPB) is maintained. Pressure boundary LEAKAGE would at first appear as unidentified LEAKAGE and can only be positively identified by inspection. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. Unidentified LEAKAGE and identified LEAKAGE are determined by performance of an RCS water inventory balance.

The RCS water inventory balance must be performed with the reactor at steady state operating conditions (stable pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows). The surveillance is modified by two notes. Note 1 states that this SR is not required to be completed until 12 hours after establishing steady state operation. The 12 hour allowance provides sufficient time to collect and process all necessary data after stable unit conditions are established.

c. The operational LEAKAGE performance criterion is specified in TS 3.1.C and 4.13, "RCS Operational LEAKAGE."

3. Provisions for SG tube repair criteria. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged.

   The following alternate tube repair criteria shall be applied as an alternative to the 40% depth-based criteria:

   a. For Unit 2 during Refueling Outage 22 and the subsequent operating cycle and for Unit 1 during Refueling Outage 23 and the subsequent operating cycle, tubes with service-induced flaws located greater than 16.7 inches below the top of the tubesheet do not require plugging. Tubes with service-induced flaws located in the portion of the tube from the top of the tubesheet to 16.7 inches below the top of the tubesheet shall be plugged upon detection.

b. For Unit 1 Refueling Outage 22 and the subsequent operating cycle, tubes with flaws having a circumferential component less than or equal to 203 degrees found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet do not require plugging. Tubes with flaws having a circumferential component greater than 203 degrees found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet shall be removed from service.

   Tubes with service-induced flaws located within the region from the top of the tubesheet to 17 inches below the top of the tubesheet shall be removed from service. Tubes with service-induced axial cracks found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging.

   When more than one flaw with circumferential components is found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet with the total of the circumferential components greater than 203 degrees and an axial separation distance of less than 1 inch, then the tube shall be removed from service. When the circumferential components of each of the flaws are added, it is acceptable to count the overlapped portions only once in the total of circumferential components.

   When one or more flaws with circumferential components are found in the portion of the tube within 1 inch from the bottom of the tubesheet, and the total of these circumferential components exceeds 94 degrees, then the tube shall be removed from service. When one or more flaws with circumferential components are found in the portion of the tube within 1 inch from the bottom of the tubesheet and within 1 inch axial separation distance of a flaw above 1 inch from the bottom of the tubesheet, and the total of these circumferential components exceeds 94 degrees, then the tube shall be removed from service. When the circumferential components of each of the flaws are added, it is acceptable to count the overlapped portions only once in the total of circumferential components.

c. For Unit 1 Refueling Outage 22 and the subsequent operating cycle, tubes in the B steam generator with permeability variation indications that may mask flaws in the bottom one inch of the tubesheet do not require plugging.

4. 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. For Unit 2 during Refueling Outage 22 and the subsequent operating cycle and for Unit 1 during Refueling Outage 23 and the subsequent operating cycle, portions of the tube greater than 16.7 inches below the top of the tubesheet are excluded from this requirement. The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements of 4.a, 4.b, and 4.c 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.
    a. Inspect 100% of the tubes in each SG during the first refueling outage following SG replacement.
    b. Inspect 100% of the tubes at sequential periods of 120, 90, and, thereafter, 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the SGs. In addition, inspect 50% of the tubes by the refueling outage nearest the midpoint of the period and the remaining 50% by the refueling outage nearest the end of the period. No SG shall operate for more than 48 effective full power months or two refueling outages (whichever is less) without being inspected.
    c. If crack indications are found in the portions of the SG tube not excluded above, 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.
5. Provisions for monitoring operational primary to secondary LEAKAGE.

b. The results of specific activity analysis in which the primary coolant exceeded the limits of Specification 3.1.D.4. In addition, the information itemized in Specification 3.1.D.4 shall be included in this report.

3. Steam Generator Tube Inspection Report

A report shall be submitted within 180 days after T_{avg} exceeds 200°F following completion of an inspection performed in accordance with the Specification 6.4.Q, Steam Generator (SG) Program. The report shall include:

a. The scope of inspections performed on each SG,
b. Active degradation mechanisms found,
c. Nondestructive examination techniques utilized for each degradation mechanism,
d. Location, orientation (if linear), and measured sizes (if available) of service induced indications,
e. Number of tubes plugged during the inspection outage for each active degradation mechanism,
f. Total number and percentage of tubes plugged to date,
g. The results of condition monitoring, including the results of tube pulls and in-situ testing,
h. The effective plugging percentage for all plugging in each SG,
i. For Unit 2 during Refueling Outage 22 and the subsequent operating cycle and for Unit 1 during Refueling Outage 23 and the subsequent operating cycle, the primary to secondary LEAKAGE rate observed in each SG (if it is not practical to assign the LEAKAGE to an individual SG, the entire primary to secondary LEAKAGE should be conservatively assumed to be from one SG) during the cycle preceding the inspection which is the subject of the report, and
j. For Unit 2 during Refueling Outage 22 and the subsequent operating cycle and for Unit 1 during Refueling Outage 23 and the subsequent operating cycle, the calculated accident induced LEAKAGE rate from the portion of the tubes below 16.7 inches from the top of the tubesheet for the most limiting accident

in the most limiting SG. In addition, if the calculated accident induced LEAKAGE rate from the most limiting accident is less than 2.03 times the maximum operational primary to secondary LEAKAGE rate, the report should describe how it was determined.

k. For Unit 2 during Refueling Outage 22 and the subsequent operating cycle and for Unit 1 during Refueling Outage 23 and the subsequent operating cycle, the results of the monitoring for tube axial displacement (slippage). If slippage is discovered, the implications of the discovery and corrective action shall be provided.

l. Following completion of a Unit 1 inspection performed in Refueling Outage 22 (and any inspections performed in the subsequent operating cycle), the number of indications and location, size, orientation, whether initiated on primary or secondary side for each service-induced flaw within the thickness of the tubesheet, and the total of the circumferential components and any circumferential overlap below 17 inches from the top of the tubesheet as determined in accordance with TS 6.4.Q.3,

m. Following completion of a Unit 1 inspection performed in Refueling Outage 22 (and any inspections performed in the subsequent operating cycle), the primary to secondary LEAKAGE rate observed in each steam generator (if it is not practical to assign leakage to an individual SG, the entire primary to secondary LEAKAGE should be conservatively assumed to be from one steam generator) during the cycle preceding the inspection which is the subject of the report,

n. Following completion of a Unit 1 inspection performed in Refueling Outage 22 (and any inspections performed in the subsequent operating cycle), the calculated accident leakage rate from the portion of the tube 17 inches below the top of the tubesheet for the most limiting accident in the most limiting steam generator, and

o. Following completion of a Unit 1 inspection performed in Refueling Outage 22 (and any other inspections performed in the subsequent operating cycle), for the B steam generator, the number of permeability variation indications including location and total circumferential extent.

ATTACHMENT 4

PROPOSED UNIT 1 TECHNICAL SPECIFICATIONS AND BASES PAGES
(IMPLEMENT FALL 2010)

**VIRGINIA ELECTRIC AND POWER COMPANY
(DOMINION)
SURRY POWER STATION UNITS 1 AND 2**

C. RCS Operational LEAKAGE

Applicability

The following specifications are applicable to RCS operational LEAKAGE whenever Tavg (average RCS temperature) exceeds 200°F (200 degrees Fahrenheit).

Specifications

1. RCS operational LEAKAGE shall be limited to:

   a. No pressure boundary LEAKAGE,

   b. 1 gpm unidentified LEAKAGE,

   c. 10 gpm identified LEAKAGE, and

   d. 150 gallons per day primary to secondary LEAKAGE through any one steam generator (SG).

2.a. If RCS operational LEAKAGE is not within the limits of 3.1.C.1 for reasons other than pressure boundary LEAKAGE or primary to secondary LEAKAGE, reduce LEAKAGE to within the specified limits within 4 hours.

   b. If the LEAKAGE is not reduced to within the specified limits within 4 hours, the unit shall be brought to HOT SHUTDOWN within the next 6 hours and COLD SHUTDOWN within the following 30 hours.

3. If RCS pressure boundary LEAKAGE exists, or primary to secondary LEAKAGE is not within the limit specified in 3.1.C.1.d, the unit shall be brought to HOT SHUTDOWN within 6 hours and COLD SHUTDOWN within the following 30 hours.

This LCO deals with protection of the reactor coolant pressure boundary (RCPB) from degradation and the core from inadequate cooling, in addition to preventing the accident analyses radiation release assumptions from being exceeded. The consequences of violating this LCO include the possibility of a loss of coolant accident (LOCA).

APPLICABLE SAFETY ANALYSES - Except for primary to secondary LEAKAGE, the safety analyses do not address operational LEAKAGE. However, other operational LEAKAGE is related to the safety analyses for LOCA; the amount of leakage can affect the probability of such an event. The safety analysis for an event resulting in steam discharge to the atmosphere assumes that primary to secondary LEAKAGE from all steam generators (SGs) is 1 gpm or increases to 1 gpm as a result of accident induced conditions. The LCO requirement to limit primary to secondary LEAKAGE through any one SG to less than or equal to 150 gallons per day is significantly less than the conditions assumed in the safety analysis.

Primary to secondary LEAKAGE is a factor in the dose releases outside containment resulting from a main steam line break (MSLB) accident. Other accidents or transients involve secondary steam release to the atmosphere, such as a steam generator tube rupture (SGTR). The leakage contaminates the secondary fluid.

The UFSAR (Ref. 2) analysis for SGTR assumes the contaminated secondary fluid is released via power operated relief valves or safety valves. The source term in the primary system coolant is transported to the affected (ruptured) steam generator by the break flow. The affected steam generator discharges steam to the environment for 30 minutes until the generator is manually isolated. The 1 gpm primary to secondary LEAKAGE transports the source term to the unaffected steam generators. Releases continue through the unaffected steam generators until the Residual Heat Removal System is placed in service.

The MSLB is less limiting for site radiation releases than the SGTR. The safety analysis for the MSLB accident assumes 1 gpm total primary to secondary LEAKAGE, including 500 gpd leakage into the faulted generator. The dose consequences resulting from the MSLB and the SGTR accidents are within the limits defined in the plant licensing basis.

The RCS operational LEAKAGE satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LIMITING CONDITIONS FOR OPERATION - RCS operational LEAKAGE shall be limited to:

a. Pressure Boundary LEAKAGE

   No pressure boundary LEAKAGE is allowed, being indicative of material deterioration. LEAKAGE of this type is unacceptable as the leak itself could cause further deterioration, resulting in higher LEAKAGE. Violation of this LCO could result in continued degradation of the RCPB. LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE.

b. Unidentified LEAKAGE

One gallon per minute (gpm) of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the containment air monitoring and containment sump level monitoring equipment can detect within a reasonable time period. Violation of this LCO could result in continued degradation of the RCPB, if the LEAKAGE is from the pressure boundary.

c. Identified LEAKAGE

Up to 10 gpm of identified LEAKAGE is considered allowable because LEAKAGE is from known sources that do not interfere with detection of unidentified LEAKAGE and is well within the capability of the RCS Makeup System. Identified LEAKAGE includes LEAKAGE to the containment from specifically known and located sources, but does not include pressure boundary LEAKAGE or controlled reactor coolant pump (RCP) seal leakoff (a normal function not considered LEAKAGE). Violation of this LCO could result in continued degradation of a component or system.

d. Primary to Secondary LEAKAGE through Any One SG

The limit of 150 gallons per day per SG is based on the operational LEAKAGE performance criterion in NEI 97-06, Steam Generator Program Guidelines (Ref. 3). The Steam Generator Program operational LEAKAGE performance criterion in NEI 97-06 states, "The RCS operational primary to secondary leakage through any one SG shall be limited to 150 gallons per day." The limit is based on operating experience with SG tube degradation mechanisms that result in tube leakage. The operational leakage rate criterion in conjunction with the implementation of the Steam Generator Program is an effective measure for minimizing the frequency of steam generator tube ruptures.

APPLICABILITY - In REACTOR OPERATION conditions where T_{avg} exceeds 200°F, the potential for RCPB LEAKAGE is greatest when the RCS is pressurized.

In COLD SHUTDOWN and REFUELING SHUTDOWN, LEAKAGE limits are not required because the reactor coolant pressure is far lower, resulting in lower stresses and reduced potentials for LEAKAGE.

LCO 3.1.C.5 measures leakage through each individual pressure isolation valve (PIV) and can impact this LCO. Of the two PIVs in series in each isolated line, leakage measured through one PIV does not result in RCS LEAKAGE when the other is leaktight. If both valves leak and result in a loss of mass from the RCS, the loss must be included in the allowable identified LEAKAGE.

4.13 RCS OPERATIONAL LEAKAGE

Applicability

The following specifications are applicable to RCS operational LEAKAGE whenever T_{avg} (average RCS temperature) exceeds 200°F (200 degrees Fahrenheit).

Objective

To verify that RCS operational LEAKAGE is maintained within the allowable limits.

Specifications

A. Verify RCS operational LEAKAGE is within the limits specified in TS 3.1.C by performance of RCS water inventory balance once every 24 hours.[1,2]

B. Verify primary to secondary LEAKAGE is ≤ 150 gallons per day through any one SG once every 72 hours. If it is not practical to assign the LEAKAGE to an individual SG, all the primary to secondary LEAKAGE should be conservatively assumed to be from one SG.

Notes:

1. Not required to be completed until 12 hours after establishment of steady state operation.
2. Not applicable to primary to secondary LEAKAGE.

BASES

SURVEILLANCE REQUIREMENTS (SR)

SR 4.13.A

Verifying RCS LEAKAGE to be within the Limiting Condition for Operation (LCO) limits ensures the integrity of the reactor coolant pressure boundary (RCPB) is maintained. Pressure boundary LEAKAGE would at first appear as unidentified LEAKAGE and can only be positively identified by inspection. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. Unidentified LEAKAGE and identified LEAKAGE are determined by performance of an RCS water inventory balance.

The RCS water inventory balance must be performed with the reactor at steady state operating conditions (stable pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows). The surveillance is modified by two notes. Note 1 states that this SR is not required to be completed until 12 hours after establishing steady state operation. The 12 hour allowance provides sufficient time to collect and process all necessary data after stable unit conditions are established.

Steady state operation is required to perform a proper inventory balance since calculations during maneuvering are not useful. For RCS operational LEAKAGE determination by water inventory balance, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows.

An early warning of pressure boundary LEAKAGE or unidentified LEAKAGE is provided by the automatic systems that monitor the containment atmosphere radioactivity and the containment sump level. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. These leakage detection systems are specified in the TS 3.1.C Bases.

Note 2 states that this SR is not applicable to primary to secondary LEAKAGE because LEAKAGE of 150 gallons per day cannot be measured accurately by an RCS water inventory balance.

The 24 hour frequency is a reasonable interval to trend LEAKAGE and recognizes the importance of early leakage detection in the prevention of accidents.

<u>SR 4.13.B</u>

This SR verifies that primary to secondary LEAKAGE is less than or equal to 150 gallons per day through any one SG. Satisfying the primary to secondary LEAKAGE limit ensures that the operational LEAKAGE performance criterion in the Steam Generator Program is met. If this SR is not met, compliance with LCO 3.1.H, "Steam Generator Tube Integrity," should be evaluated. The 150 gallons per day limit is measured at room temperature as described in Reference 4. The operational LEAKAGE rate limit applies to LEAKAGE through any one SG.

If it is not practical to assign the LEAKAGE to an individual SG, all the primary to secondary LEAKAGE should be conservatively assumed to be from one SG. The surveillance is modified by a Note, which states that the Surveillance is not required to be performed until 12 hours after establishment of steady state operation. For RCS primary to secondary LEAKAGE determination, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows.

The surveillance frequency of 72 hours is a reasonable interval to trend primary to secondary LEAKAGE and recognizes the importance of early leakage detection in the prevention of accidents. The primary to secondary LEAKAGE is determined using continuous process radiation monitors or radiochemical grab sampling in accordance with the EPRI guidelines (Ref. 4).

c. The operational LEAKAGE performance criterion is specified in TS 3.1.C and 4.13, "RCS Operational LEAKAGE."

3. Provisions for SG tube repair criteria. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged.

   The following alternate tube repair criteria shall be applied as an alternative to the 40% depth-based criteria:

   a. For Unit 2 during Refueling Outage 22 and the subsequent operating cycle and for Unit 1 during Refueling Outage 23 and the subsequent operating cycle, tubes with service-induced flaws located greater than 16.7 inches below the top of the tubesheet do not require plugging. Tubes with service-induced flaws located in the portion of the tube from the tubesheet to 16.7 inches below the top of the tubesheet shall be plugged upon detection.

4. 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. For Unit 2 during Refueling Outage 22 and the subsequent operating cycle and for Unit 1 for Refueling Outage 23 and the subsequent operating cycle, portions of the tube greater than 16.7 inches below the top of the tubesheet are excluded from this requirement. The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements of 4.a, 4.b, and 4.c 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.
   a. Inspect 100% of the tubes in each SG during the first refueling outage following SG replacement.
   b. Inspect 100% of the tubes at sequential periods of 120, 90, and, thereafter, 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the SGs. In addition, inspect 50% of the tubes by the refueling outage nearest the midpoint of the period and the remaining 50% by the refueling outage nearest the end of the period. No SG shall operate for more than 48 effective full power months or two refueling outages (whichever is less) without being inspected.
   c. If crack indications are found in the portions of the SG tube not excluded above, 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.
5. Provisions for monitoring operational primary to secondary LEAKAGE.

b. The results of specific activity analysis in which the primary coolant exceeded the limits of Specification 3.1.D.4. In addition, the information itemized in Specification 3.1.D.4 shall be included in this report.

3. <u>Steam Generator Tube Inspection Report</u>

A report shall be submitted within 180 days after T_{avg} exceeds 200°F following completion of an inspection performed in accordance with the Specification 6.4.Q, Steam Generator (SG) Program. The report shall include:

a. The scope of inspections performed on each SG,
b. Active degradation mechanisms found,
c. Nondestructive examination techniques utilized for each degradation mechanism,
d. Location, orientation (if linear), and measured sizes (if available) of service induced indications,
e. Number of tubes plugged during the inspection outage for each active degradation mechanism,
f. Total number and percentage of tubes plugged to date,
g. The results of condition monitoring, including the results of tube pulls and in-situ testing,
h. The effective plugging percentage for all plugging in each SG,
i. For Unit 2 during Refueling Outage 22 and the subsequent operating cycle and for Unit 1 during Refueling Outage 23 and the subsequent operating cycle, the primary to secondary LEAKAGE rate observed in each SG (if it is not practical to assign the LEAKAGE to an individual SG, the entire primary to secondary LEAKAGE should be conservatively assumed to be from one SG) during the cycle preceding the inspection which is the subject of the report, and

j. For Unit 2 during Refueling Outage 22 and the subsequent operating cycle and for Unit 1 during Refueling Outage 23 and the subsequent operating cycle, the calculated accident induced LEAKAGE rate from the portion of the tubes below 16.7 inches from the top of the tubesheet for the most limiting accident in the most limiting SG. In addition, if the calculated accident induced LEAKAGE rate from the most limiting accident is less than 2.03 times the maximum operational primary to secondary LEAKAGE rate, the report should describe how it was determined.

k. For Unit 2 during Refueling Outage 22 and the subsequent operating cycle and for Unit 1 during Refueling Outage 23 and the subsequent operating cycle, the results of the monitoring for tube axial displacement (slippage). If slippage is discovered, the implications of the discovery and corrective action shall be provided.

ATTACHMENT 5

LIST OF REGULATORY COMMITMENTS

**VIRGINIA ELECTRIC AND POWER COMPANY
(DOMINION)
SURRY POWER STATION UNITS 1 AND 2**

LIST OF REGULATORY COMMITMENTS

The following table identifies those actions committed by Dominion for Surry Power Station Units 1 and 2 with respect to the one-time alternate repair criteria for steam generator tube repair. These commitments, which supersede those in our July 28, 2009 permanent alternate repair criteria license amendment request letter (Serial No. 09-455), are a restatement of the commitments reflected in our September 16, 2009 permanent alternate repair criteria RAI response letter (Serial No. 09-455A).

Commitment	Due Date/Event
Dominion commits to monitor for tube slippage as part of the SG tube inspection program for Unit 1 and Unit 2.	Starting with Unit 2 Refueling Outage 22 and during subsequent Unit 1 and Unit 2 SG inspections
Dominion commits to perform a one-time verification of the tube expansion to locate any significant deviations in the distance from the top of tubesheet to the beginning of expansion transition. If any significant deviations are found, the condition will be entered into the plants corrective action program and dispositioned. Additionally, Dominion commits to notify the NRC of significant deviations.	Prior to the startup following Unit 2 Refueling Outage 22 and Unit 1 Refueling Outage 23
Dominion commits to plug eleven Unit 2 tubes that have been identified as not being expanded within the tubesheet in either the hot leg or cold leg.	During the Unit 2 Refueling Outage 22
Dominion commits to plug three Unit 1 tubes that have been identified as not being expanded within the tubesheet in either the hot leg or cold leg.	During the Unit 1 Refueling Outage 23
Dominion commits to the following: For the Condition Monitoring assessment, the component of operational leakage from the prior cycle from below the H* distance will be multiplied by a factor of 2.03 and added to the total accident leakage from any other source and compared to the allowable accident induced leakage limit. For the Operational Assessment, the difference between the allowable accident induced leakage and the accident induced leakage from sources other than the tubesheet expansion region will be divided by 2.03 and compared to the observed operational leakage. An administrative operational leakage limit will be established to not exceed the calculated value.	For every operating cycle following Unit 2 Refueling Outage 22 and Unit 1 Refueling Outage 23