ATTACHMENT 1
Description and Assessment

Subject: Application for Revision to TS 5.5.9, "Steam Generator (SG) Program," for a One-Time Deferral of Steam Generator Tube Inspections

ATTACHMENT 1
Description and Assessment

1.0 SUMMARY DESCRIPTION

In accordance with 10 CFR 50.90, "Application for amendment of license, construction permit, or early site permit," Exelon Generation Company, LLC (EGC) requests amendments to the Technical Specifications (TS) for Renewed Facility License Nos. NPF-37 and NPF-66 for Byron Station, Units 1 and 2 (Byron).

This proposed amendment request revises TS 5.5.9, "Steam Generator (SG) Program," for a one-time revision to the frequency for SG tube inspections. The requested TS amendments support deferral of the TS required inspections until the next Unit 2 refueling outage, which is scheduled in spring 2022 (B2R23).

2.0 DETAILED DESCRIPTION

2.1 Reason for the Proposed Change

On January 27, as renewed on April 21, 2020 a Public Health Emergency (PHE) was declared for the entire United States in responding to the coronavirus (i.e., COVID-19 Virus). On March 9, 2020, the State of Illinois declared a disaster proclamation over the coronavirus outbreak. The Centers for Disease Control and Prevention (CDC) issued recommendations advising "social distancing" or sequestering individuals to prevent the spread of the COVID-19 virus.

On May 5, 2020, the Governor of Illinois announced that the State of Illinois would use health statistics and health care capacity to implement a five-phase plan to reopen the state. As of June 26, 2020, Byron is in a region that is in Phase 4 of this plan, which limits gatherings to 50 or fewer people and requires face coverings and social distancing. In Phase 5, the final phase, the economy fully reopens with safety precautions continuing. To reach Phase 5, a vaccine, highly effective treatment, or herd immunity would need to be established.

To support the specific SG inspections during the Byron Unit 2 fall 2020 refueling outage, there will be an estimated 190 people onsite, many of whom travel from other areas of the country. As such, this request is being made to support Byron's proactive efforts to follow the CDC recommendations (e.g., social distancing, group size limitations, self-quarantining, etc.) by limiting the number of people onsite and in our neighboring communities.

EGC has implemented practices beyond the CDC recommendations. These include self-screening questions of all workers prior to reporting to work, temperature monitoring and questioning of all people prior to entering a company site or property and maximizing remote enabled employees. As of June 26, 2020, 38 percent of Byron's work force is remote enabled. Byron has performed a line-by-line review of all items for the fall 2020 refueling outage to minimize the number of people who have to travel to the site. All items that are not necessary for nuclear safety or reliable generation are being deferred from the scope of the fall 2020 refueling outage.

The nature of the SG inspections conflicts with the CDC recommendations since it requires workers to be in constant proximity to each other in a hot and radiological environment, increasing the likelihood of individuals contracting COVID-19 and potentially inducing a rapid spread (e.g., craft support for closure assembly/disassembly, platform construction, robot manipulations). The personal protective equipment (PPE), consisting of masks issued to all individuals onsite, are required to be used in situations where social distancing cannot be maintained, adds time and individual effort to activities, which in turn can potentially increase human performance and safety risk. Additionally, these inspections require a specialty vendor that maintains unique and complex qualifications. Losing people due to a spread of the COVID-19 virus would cause a situation where the proper technical knowledge would not be available to satisfactorily complete this work (e.g., minimal 14-day isolation and likely to be more than one individual based on having to work in close proximity for the work). This could result in not meeting the TS requirement for tube integrity and examination scope and limit the ability to reassemble the SGs.

EGC evaluated potential mitigation strategies, including moving personnel to either a building external to the Protected Area (i.e., Byron Training Building) or to the vendor's location. Mitigation challenges have been identified with both options. The fiber running from Byron Containment to the Training Building (greater than 3000 ft. in length) had been severed and required repair. Once repaired, the fiber required testing to validate the quality of the data transfer. In evaluating the potential to move personnel, the number of people that could potentially be relocated would only offset the total of 190 individuals supporting the B2R22 SG inspections by approximately 35 individuals.

Discussions with the vendor identified no additional or new technology to improve data transmission or to conduct the SG inspections. Based on the nature of the SG inspections and the CDC requirements to prevent the spread of the COVID-19 virus, these potential mitigation measures do not preclude the need for the amendments for B2R22.

As a result of the current and ongoing pandemic situation, an Operational Assessment (OA) has been developed to justify deferral of the SG inspections until the next Unit 2 refueling outage (approximately 52 effective full power months from the last inspection). Attachment 5 provides this OA, which addresses both existing and potential degradation mechanisms. EGC has determined this deferral to involve less risk than performing the inspections under the current situation.

2.2 Description of the Proposed Change

The proposed change to Byron TS 5.5.9, "Steam Generator (SG) Program," is being requested as described below (added text **underlined and bolded**).

TS 5.5.9.d.3 currently states (in part):

> For Unit 2, after the first refueling outage following SG installation, inspect each SG at least every 48 effective full power months or at least every other refueling outage (whichever results in more frequent inspections). In addition, the minimum number of tubes inspected at each scheduled inspection shall be the number of tubes in all SGs divided by the number of SG inspection outages scheduled in each inspection period as

> defined in a, b, and c below. If a degradation assessment indicates the potential for a type of degradation to occur at a location not previously inspected with a technique capable of detecting this type of degradation at this location and that may satisfy the applicable tube plugging criteria, the minimum number of locations inspected with such a capable inspection technique during the remainder of the inspection period may be prorated. The fraction of locations to be inspected for this potential type of degradation at this location at the end of the inspection period shall be no less than the ratio of the number of times the SG is scheduled to be inspected in the inspection period after the determination that a new form of degradation could potentially be occurring at this location divided by the total number of times the SG is scheduled to be inspected in the inspection period. Each inspection period defined below may be extended up to 3 effective full power months to include a SG inspection outage in an inspection period and the subsequent inspection period begins at the conclusion of the included SG inspection outage.

The revised TS 5.5.9.d.3 (in part) will state:

> For Unit 2, after the first refueling outage following SG installation, inspect each SG at least every 48 effective full power months or at least every other refueling outage (whichever results in more frequent inspections)**, with the exception that each SG is to be inspected during the third refueling outage in B2R23 following inspections completed in refueling outage B2R20.** In addition, the minimum number of tubes inspected at each scheduled inspection shall be the number of tubes in all SGs divided by the number of SG inspection outages scheduled in each inspection period as defined in a, b, and c below. If a degradation assessment indicates the potential for a type of degradation to occur at a location not previously inspected with a technique capable of detecting this type of degradation at this location and that may satisfy the applicable tube plugging criteria, the minimum number of locations inspected with such a capable inspection technique during the remainder of the inspection period may be prorated. The fraction of locations to be inspected for this potential type of degradation at this location at the end of the inspection period shall be no less than the ratio of the number of times the SG is scheduled to be inspected in the inspection period after the determination that a new form of degradation could potentially be occurring at this location divided by the total number of times the SG is scheduled to be inspected in the inspection period. Each inspection period defined below may be extended up to 3 effective full power months to include a SG inspection outage in an inspection period and the subsequent inspection period begins at the conclusion of the included SG inspection outage.

Attachment 2 provides the existing TS page for Byron Station, Units 1 and 2, marked up to show the proposed change. To assist the NRC's review of the proposed change, Attachment 3 provides the revised (i.e., camera-ready) TS pages.

Although the proposed change only affects Byron Station, Unit 2, this submittal is being docketed for Byron Station, Units 1 and 2, since the TS are common to Units 1 and 2 for the Byron Station.

3.0 TECHNICAL EVALUATION

3.1 System Description

The Byron SGs are vertical shell and U-tube heat exchangers with integral moisture separating equipment. Byron Unit 2 has Westinghouse Model D-5 SGs equipped with 4,570 Alloy 600 thermally treated (Alloy 600TT) tubes. The tubes have an outer diameter of 0.750" and nominal wall thickness of 0.043". The tube support plates are made of stainless steel. The tubes were hydraulically expanded to the full length of the tube sheet. At the time of the Byron Unit 2 fall 2020 refueling outage (B2R22), the Byron Unit 2 SG will have been operating for approximately 29.9 effective full power years.

On the primary side, the reactor coolant flows through the inverted U-tubes, entering and leaving through nozzles located in the hemispherical bottom head of the SG. The head is divided into inlet and outlet chambers by a vertical divider plate extending from the head to the tube sheet.

Steam is generated on the shell side, flows upward and exits through the outlet nozzle at the top of the vessel. During normal operation for Byron Unit 2, feedwater flows through a flow restrictor, directly into the counter flow preheat section and is heated almost to saturation temperature before entering the boiler section. Subsequently, the water-steam mixture flows upward through the tube bundle and into the steam drum section, where individual centrifugal moisture separators remove most of the entrained water from the steam. The steam continues to the secondary separators for further moisture removal, increasing its quality to a minimum of 99.75% for Unit 2. The moisture separators recirculate the separated water through the annulus between the shell and tube bundle wrapper via the space formed by the distribution plate. The returning flow then combines with the already preheated water-steam mixture for another passage through the SG. Dry steam exits through the outlet nozzle, which is provided with a steam flow restrictor.

3.2 Technical Analysis

The current TS requirement is to inspect each SG at least every 48 effective full power months (EFPM) or at least every other refueling outage (whichever results in more frequent inspections). The proposed one-time revision allows the inspection deferral of each SG to after three operating cycles following refueling outage B2R20 performed in October 2017.

Significant operating experience has been gained over the course of 17 years since the current TS inspection frequency was established and provides justification for deferring the inspection by one operating cycle.

The susceptibility to stress corrosion cracking (SCC) in Alloy 600TT has limited the maximum SG inspection frequency allowed by TS to every other refueling outage. However, operating experience for nearly forty years has generally shown no propensity for rapidly increasing crack initiation rates in Alloy 600TT SG tubes. Byron Unit 2 has successfully operated for 21 full cycles and performed 18 inspections without detection of any SCC outside of the H* region. The proposed change of one-time revision to allow three operating cycles between inspections has been evaluated to meet the structural integrity and accident induced leakage performance

criteria even if SCC initiation is assumed to have occurred prior to the last SG inspections. Based on this operating experience and a supporting OA, the proposed TS change to require inspection of the tubing after three operating cycles is acceptable.

To justify the deferral of the inspections to after a third operating cycle, the SG Program requires assessments to ensure safe SG inspection intervals that are based on measurable parameters that monitor SG performance, such as results of SG tube inspections and operational leakage. Objective criteria to assess performance are established based on deterministic and probabilistic analyses and performance history. In addition, the TS requirements on operational leakage require a plant shutdown if the limits are exceeded. During the extended operating cycle from B2R22 to B2R23, Byron Unit 2 will decrease its normal 100 gallons per day (gpd) shutdown criteria for primary-to-secondary leakage (required by the EPRI Steam Generator Management Program: PWR Primary-to-Secondary Leak Guidelines, Revision 4, Report 1022832, November 2011 (Reference 10)) down to 30 gpd for confirmed and sustained leakage at or above that level. This ensures that the failure to meet a performance criterion, while undesirable, will not result in an immediate safety concern. Therefore, the proposed one-time extension of the existing SG inspection frequency is acceptable.

3.2.1 Recent Operational Experience Summary

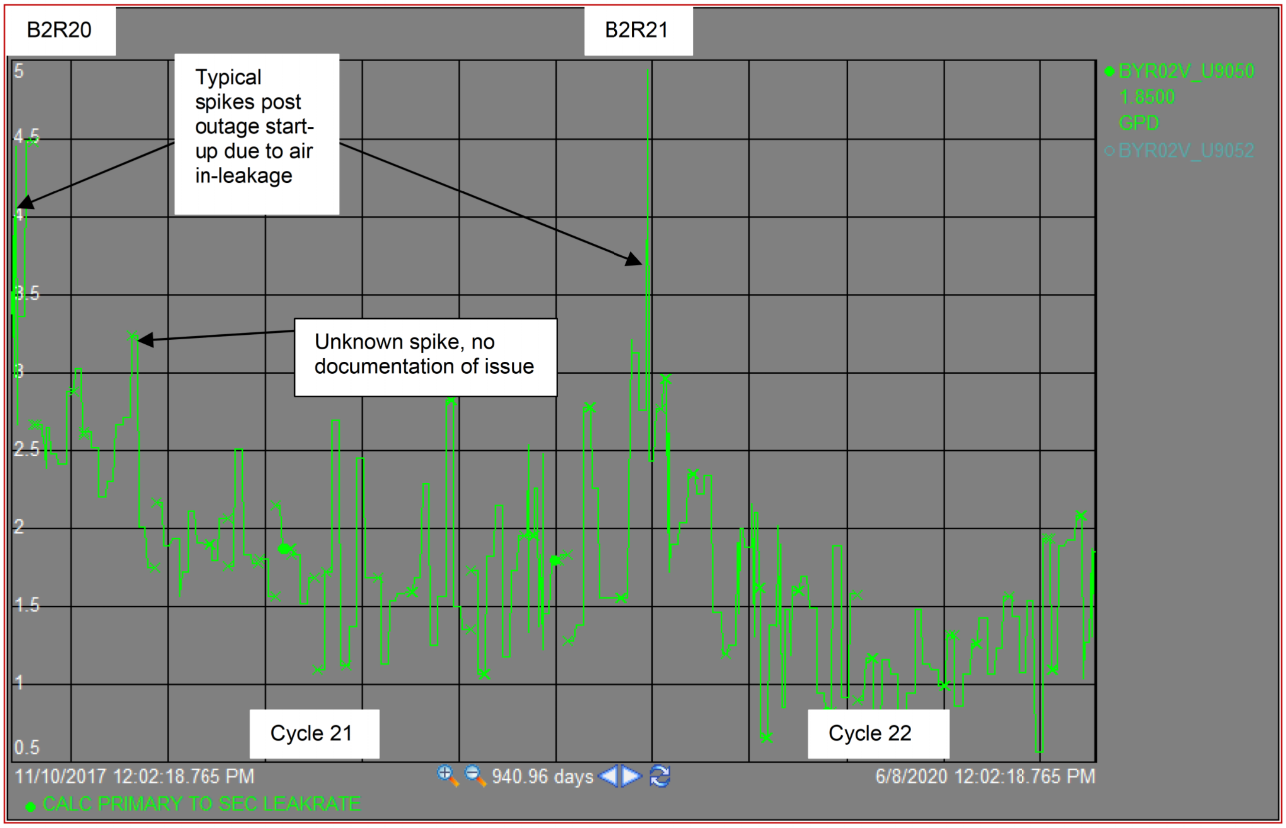
3.2.1.a Trends of Primary to Secondary Leakage

No primary to secondary side leakage has been noted for operating Cycles 21 and 22. As seen in Figure 1, all trends are below 3 gallons per day (gpd), except for a spike occurring around February 23, 2018, possible due to computer point error since no issue was documented. Other typical spikes which occurred post refueling outages were due to air in-leakage issues and not related to primary to secondary leakage. The primary to secondary leak rate determination utilizes the Condenser Offgas method, which uses steam jet air ejector (SJAE) flow. During unit start-ups, these flows are normally higher due to systems being returned to service. The high SJAE flow causes a higher apparent primary to secondary leak rate during start-up and post outage which are not related to actual primary to secondary leakage.

Primary to secondary leak rates are quantified through periodic sampling of the primary coolant system and the condenser off gas/air ejectors, with leak rate calculated based on mass-balance of noble gas isotopes. Leak rates are continuously monitored using on-line radiation monitors and supporting software available in the control room.

Section 3.2.4 discusses the threshold for actions due to confirmed primary-to-secondary leakage and planned mitigating strategy that will be implemented during the extended operating cycle from B2R22 to B2R23.

Figure 1: Primary to Secondary Leak Rate for Operating Cycles 21 and 22



3.2.1.b Main Steam Pressure Trending and T-ave Impact

Chemical cleaning (soft cleaning) of the secondary side of all 4 SGs was performed during B2R20 (Fall 2017) and recovered approximately 8-10 psi of main steam pressure. Although Advanced Scale Conditioning Agent (ASCA) provided a short-term main steam pressure recovery, a decline in pressure started 8 months post ASCA. Late in 2019, the station investigated a main steam (MS) pressure loss and provided the following recommendations to Byron's Site Leadership Team in January 2020:

Recommendation 1: Increase T-ave by 1 degree, considered short term, as needed.
Recommendation 2: Chemical Cleaning to mitigate MS pressure loss.
Recommendation 3: Review and determine appropriate chemistry changes to recover MS pressure, long term.

Based on discussions with the Byron Site Leadership Team, no de-plugging is planned for the near future outages.

Note: Presently, Byron Unit 2 MS pressure is expected to hit Valves Wide Open (VWO) some time prior to B2R23.

An increase of T-ave of up to 1 degree for less than two operating cycles is not expected to adversely impact SCC initiation in the SG tubes as other Alloy 600TT units have operated at this and higher T-ave values for many years.

3.2.1.c Summary of Most Recent Primary and Secondary (e.g., FOSAR) Inspections, Detected Degradation and Its Location

The Byron Unit 2 (B2R20) report, "Byron Station, Unit 2 Steam Generator Tube Inspection Report for Refueling Outage 20," dated April 5, 2018 (Reference 4) contains the high-level summary of the most recent primary and secondary inspections, including degradation detected and location of the degradation.

3.2.1.d Number of Tubes Plugged and Reason for Plugging

The number of tubes plugged for Byron Unit 2 and plugging percentage are noted in Table 1. Table 2 represents the reasons for tube plugging during each SG inspection outage.

Table 1: Byron Unit 2 Plugging Status

Plugging Summary (Post B2R20)	SG 2A	SG 2B	SG 2C	SG 2D	TOTAL
Total Tubes Plugged	159	142	166	42	509
Total PCT Plugged	3.48%	3.11%	3.63%	0.92%	2.78%
Plugging Limit	5%	5%	5%	5%	5%

Table 2: Byron Unit 2 Plugging History by Degradation Mechanism

Date	Outage	Plant EFPY (1)	TSP / TTS / U-Bend / Dent SCC	TTS OD Mech Groove	TSP Wear	Pre-Htr Wear	AVB Wear	OD Vol Near TSPs	Foreign Object Wear	Other	Prevent	Total
	PSI	0	0	0	0	0	0	0	0	11	0	11
1/7/1989	B2R01	1.192	0	0	0	0	2	0	7	2	0	11
9/1/1990	B2R02	2.354	0	0	0	0	19	1	0	1	0	21
2/28/1992	B2R03 (2)	3.484	0	0	0	0	25	0	0	4	0	29
9/3/1993	B2R04	4.674	0	0	0	0	33	0	3	0	0	36
2/11/1995	B2R05	5.902	0	0	0	0	21	0	8	0	0	29
	B2F17		0	0	0	0	0	0	4	0	0	4
8/8/1996	B2R06	7.217	0	0	0	0	19	0	2	5	0	26
4/11/1998	B2R07	8.629	0	29	0	0	1	2	5	1	0	38
10/23/1999	B2R08	10.038	0	0	0	1	9	1	3	0	0	14
4/7/2001	B2R09 (3)	11.426	0	0	0	0	0	1	3	0	0	4
	B2F23		0	0	0	0	0	0	3	0	0	3
9/17/2002	B2R10	12.823	0	0	0	1	2	0	11	0	0	14
3/23/2004	B2R11	14.285	0	0	0	0	1	0	1	0	90 (4)	92
9/27/2005	B2R12	15.739	0	0	0	6	1	0	7	1	2	17
4/1/2007	B2R13	17.191	0	0	0	0	3	0	3	0	11	17
10/6/2008	B2R14	18.578	0	0	0	3	1	0	3	0	6	13
4/19/2010	B2R15	20.052	0	0	0	0	0	0	1	0	0	1
9/26/2011	B2R16	21.397	0	0	0	7	1	0	4	0	16	28
4/8/2013	B2R17	22.832	No Inspections performed									
9/29/2014	B2R18	24.234	0	0	0	0	4	0	1	0	0	5
4/18/2016	B2R19	25.694	No Inspections performed									
10/2/2017	B2R20	27.054	0	0	1	0	2	2	0	0	91 (5)	96
4/8/2019	B2R21	28.504	No Inspections performed									
10/5/2020	B2R22	29.954	-	-	-	-	-	-	-	-	-	-
		Totals	0	29	1	18	144	7	69	25	216	509

Notes:

(1) Byron Unit 2 Cumulative Effective Full Power Years.

(2) Eight tie rod tube locations per SG, where stub tube plugs were installed, were plugged with mechanical roll plugs. These were in non-tube locations and are not included in the number of tubes plugged summation.

(3) SG inspections in SG B only.

(4) Preventatively plugged and stabilized 90 tubes in 2A SG due to waterbox cap plate degradation.

(5) Preventatively plugged and stabilized 91 tubes in 2C SG due to waterbox cap plate degradation.

3.2.1.e Relevant Operating Experience that Could Impact Tube Integrity

Deposit Loading

Based on the deposit loading amounts for Byron Unit 2, as shown below, the deposits do not impose an adverse impact to tube integrity. During B2R20 in October 2017, the total inventory of deposits was reduced by 3,208 lbs, or 21%, using "soft" chemical cleaning application plus sludge lancing. The SG water level has trended steady and visual inspections of the uppermost tube support quatrefoil broach openings during B2R20 did not show any significant blockage.

Table 3: Byron Unit 2 Historical Deposits Since Cycle 8

RFO	Iron (as Fe3O4) Transported (4 SG Total)	Lbs Removed via Blowdown (cycle) (4 SG Total)	Lbs Removed via SL and ASCA (4 SG Total)	Lbs Sludge Remaining (cycle net) (4 SG Total)	Cumulative Lbs Sludge Remaining (4 SG Total)**
2R08	356	17.8	269.5	68.7	14,356
2R09	386	19.3	185.0	181.7	14,538
2R10	385	19.3	207.0	158.8	14,696
2R11	600	30	192.5	377.5	15,074
2R12	349	17.5	204.5	1271	15,201
2R13	286	14.3	284.5	-12.5	15,188
2R14	448	22.4	292.0	133.6	15,322
2R15	163	5.8	139.5	17.5	15,340
2R16	193	277.3	146.5	-231.1	15,109
2R17	228	187	N/A	41	15,150
2R18	156	231	73.5	-148.5	15,002
2R19	145	188	N/A	-43	14,959
2R20	180	68	295 (+2913 removed via ASCA*)	-3096	11,863**
2R21	182	151	N/A	31	11,894

*Advanced Scale Conditioning Agent (ASCA) cleaning performed during B2R20
**Based on discussions with DEI regarding Byron's Unit 2 deposits, Byron Unit 2 changed from heavy loaded SGs to light-medium loaded SGs.

Chemistry (Operating Cycles 21 and 22)

There were no adverse changes to SG Chemistry in Cycle 21 or Cycle 22.

Cycle 21 SG Chemistry:

- No CEI-R points were accrued this cycle, indicating excellent chemistry control and practices.

- A total of 131.5 pounds of iron (181.5 lbs iron oxide) was transported to the 4 SGs this cycle and a total of 109.5 pounds of iron (151.1 lbs as iron oxide) was removed from the SGs via blowdown.

Cycle 22 SG Chemistry (as of June 2020):

- A small CEI impacts were taken in May 2019 (0.02) and November 2019 (0.01) due to SG sodium excursions (max 2.26 ppB and 0.98 ppB, respectively).

- Molar Ratio control on Unit 2 was on average 0.31 (control band limits are 0.15 to 0.45).

Steam Drum

The only Steam Drum component where active degradation has been observed is in the Primary Moisture Separators. Ultrasonic data has been taken shortly after discovery in 2005 and during SG inspections ultrasonic testing is performed on one to two SGs and the data from each inspection outage is used for developing wear rates, which are used for predicting through wall penetration. Based on review of ultrasonic thickness reading data on all four Byron Unit 2 SG Primary Moisture Separators, that includes the orifice ring assemblies, riser barrels, swirl vane blades, downcomer barrels, and tangential nozzles, the earliest prediction that a through-wall penetration could appear would be no sooner than 2027.

The spacer tab is the only component that could become a loose part if the tab thinned and broke off. During B2R20, six of thirty-two spacer tabs in SG 2A and nine of thirty-two spacer tabs inspected in the 2C SG were visually observed to possess degradation (i.e., missing material), but no through-wall holes. Given that the visual estimates of all spacer plates' remaining thicknesses in SG 2A and SG 2C were greater than the 0.10-inch acceptance criteria, the as-found conditions of the spacer tabs are acceptable. Though the wear rate is not known, for the spacer tab, due to only one data set, these spacer tabs have been in operation since start-up and would not be expected to degrade enough to cause a loose part within the SGs for one additional cycle.

Therefore, based on the operating experience summary described above, it was concluded that one additional operating cycle is justified with no adverse consequences to extend the planned SG inspection until the next Unit 2 refueling outage in April 2022 (B2R23).

Foreign Object Review

Existing Foreign Object Remaining in SGs – Top of Tubesheet, Pre-heater, and Upper bundle: The visual inspections conducted during B2R20 identified six (6) foreign objects that remain within the SGs. These are identified in Table 4.

Table 4: Byron B2R20 Foreign Objects Remaining in SGs Based on Visual Inspection

SG	Object ID	Elev	Row	Col	Object Description	Object Dimensions (inch)	Legacy? Yes/No Outage Found	Priority (Att. 5)	Fixity
2A	2A001	TTS	28 29	105 105	Weld Slag	0.75x0.6x0.312	Yes B2R11	1[(1)]	Fixed. Wedged
2A	2A002	TTS	48 49	48 48	Weld Slag	0.5x0.312x0.312	Yes B2R15	2[(1)]	Fixed. Wedged
2A	2A003	TTS	38 39	41 41	Screw	0.6x0.312x0.312	Yes B2R18	2[(1)]	Fixed. Wedged
2B	2B002	TSP 02C	26	64	Wire	0.1x0.01 diam	No	3	Fixed. Stuck in
2B	2B003	TSP 02C	27	89	Wire	0.375x0.01 diam	No	3	Fixed. Stuck in
2C	2C002	TTS	12 13	111 111	Sludge Cluster	0.32x0.312x0.312	Yes B2R18	2[(1)]	Fixed. Wedged

Note:
(1) Can be reclassified to Priority 3. Has not caused tube wear over several cycles of operation.

During B2R20, objects 2A001, 2A002, 2A003, and 2C002 were again classified as Priority 1 or Priority 2 objects. However, these objects are firmly wedged between tubes and are unable to vibrate to cause tube wear. The affected tubes remain in service and examined by eddy current each SG inspection. No tube wear has been detected by eddy current inspections from these objects in the B2R20 outage or in previous outages.

Note: The one potential Priority 1 object (2A001) has remained in place since B2R11 (spring 2004) even after eight (8) sludge lancings and an ASCA cleaning in B2R20. This experience shows that it is unlikely to become detached during future cycles.

Backing Bars from SG 2C Waterbox Cap Plate

The SG 2C waterbox cap plate contains two cut out plates that were welded back into place during vessel manufacturing. The cut outs were used to gain temporary access to the waterbox. Six backing bars were used on the bottom side of the cap plate to facilitate the welding process. During the B2R20 visual inspection, one of the six backing bars was found missing from the cap plate and was located within the tube bundle on top of TSP 02C, the lowest elevation tube support in the pre-heater section of the SG. The backing bar was subsequently removed from the SG. No tube degradation was caused by this object. Consequently, 91 tubes along the periphery and T-slot were preventatively plugged and stabilized to assure that tube integrity is not compromised should any of the remaining backing bars detach and cause degradation to these tubes.

Note: The Byron Unit 2 (B2R20) NRC Report (Reference 4), "Byron Station, Unit 2 Steam Generator Tube Inspection Report for Refueling Outage 20," dated April 5, 2018 (ML18095A116) contains the high-level summary of the 2C backing bar issue.

Foreign Material

A search of issue reports related to Foreign material was performed for Byron Unit 2 operating Cycles 21 and 22, and no indications of ingress of foreign material into the Unit 2 SGs occurred from other systems during that time frame.

3.2.2 Condition Monitoring (CM) During Refueling Outage B2R20 (October 2017)

A summary of the Condition Monitoring (CM) results for B2R20 was submitted to the NRC on April 5, 2018, "Byron Station, Unit 2 Steam Generator Tube Inspections Report for Refueling Outage 20," (ML18095A116). The detailed inspection results and inputs used to perform the CM assessment are provided in the CM and OA developed for B2R20 (EC 620886, "Final Condition Monitoring and Operational Assessment, Including Foreign Object Evaluation," dated October 2017 (Reference 5)).

3.2.2.a For Each Degradation Mechanism Detected, the Most Limiting As Found Condition Compared to the Tube Performance Criteria

For each degradation mechanism detected at the last Byron Unit 2 SG inspection in B2R20 (October 2017), the most limiting as found condition was compared to the tube performance criteria and is provided in Table 5 below.

The limiting case degraded condition detected at B2R20 for each degradation mechanism was less than the condition monitoring limit; therefore, Structural Integrity Performance Criteria (SIPC) were satisfied. The severity of the limiting degraded condition for each degradation mechanism is expressed as a percent through wall (%TW) depth and compared to the CM limit calculated for a given bounding axial extent. The SIPC is met if the as found worst case depth ("Maximum Depth Recorded" in Table 5) is less than the allowable depth ("CM Limit Depth" in Table 5). As can be seen for all degradation mechanisms detected in B2R20, the smallest margin, was for single land wear at a quatrefoil support and was approximately 12.3%TW, if uniform depth "flat" wear is assumed and 18.1%TW if tapered wear is assumed.

Table 5: Summary of Condition Monitoring performance for Existing Degradation Mechanism during B2R20 (October 2017) (Reference 5)

Degradation Mechanism Detected at B2R20	Maximum Depth Recorded (%TW)	Projected Max Depth at B2R20 from B2R18 OA (%TW)	CM Limit Depth (%TW) (1)	Margin to CM Limit (%TW)	Bounding Axial Extent (inch)	ETSS
Cracking Mechanisms (ODSCC/ PWSCC)	None Detected	N/A	N/A	N/A	N/A	N/A
AVB Wear	42	53.8	63.0	21.0	0.5 (3)	96004.3
TSP Single Land Wear	39	52.3	51.3 (Flat) 57.1 (Tapered)	12.3 (F) 18.1 (T)	1.125 (3)	96910.1
Baffle Plate Wear	26 (4)	22.5 (5)	53.6 (Flat) 57.1 (Tapered)	27.6 (F) 31.1 (T)	0.75 (3)	96910.1
Foreign Object Wear	35	New (2)	52.0	17.0	0.55" Axial (Measured: 0.19" Ax 0.31" Circ)	21998.1

Notes:

(1) CM Limit based on bounding case Secondary Side pressure of 812 psig and 3ΔP of 4248 psid at the bounding axial extent. The tapered CM limits are based on effective (i.e., structural) depth and axial extent rather than max depth and axial extent.

(2) Existing Foreign Object (FO) Wear is not predicted to grow due to FOs removed at B2R18 or earlier outage.

(3) Limiting size, based on dimension of support structure.

(4) Inspection transient, this flaw was sized with +Point™ probe in B2R20 where it had been previously sized by bobbin in B2R18. A comparison of B2R18 and B2R20 bobbin sizing saw no change. The +Point™ sizing is believed to be a more accurate representation.

(5) Projected growth was based on B2R18 bobbin size of 17%TW and prior bobbin growth rates rather than +Point™.

3.2.2.b Discuss any tubes that required flaw profiling to demonstrate condition monitoring was met

No tubes required flaw profiling to demonstrate that the CM limit was not exceeded.

3.2.3 Operational Assessment (OA) Supporting an Additional Operating Cycle

3.2.3.a The existing degradation mechanisms observed at Byron Unit 2 that require an OA are as follows:

- Mechanical wear from Anti-Vibration Bar (AVB) support structures
- Mechanical wear from quatrefoil Tube Support Plate (TSP) structures
- Mechanical wear from drilled hole baffle plate structures
- Mechanical wear from foreign objects

In addition to the existing degradation mechanisms above, several potential degradation mechanisms were considered in light of Byron Unit 2's request to operate for 3-cycles between SG inspections. An OA for potential degradation mechanisms predicts the behavior of postulated flaws that could have been present at or prior to the last SG inspection in B2R20 and those that could have initiated during the 3-cycle operating period. The potential degradation mechanisms for which an OA was performed are as follows:

- Axial Outer Diameter Stress Corrosion Cracking (ODSCC) at TSP intersections on known high residual stress tubes
- Circumferential ODSCC at the hot leg TTS expansion transition
- Axial ODSCC at tube dings and dents (both high stress and non-high stress tubes)
- Axial ODSCC at TSP intersections on non-high residual stress tubes
- Axial ODSCC at the hot leg TTS expansion transition
- Axial ODSCC in the freespan, immediately above TSPs[1]
- Axial Primary Water Stress Corrosion Cracking (PWSCC) in small radius U-bends
- Axial and circumferential PWSCC at the TTS (generally bounded by ODSCC analyses)
- OD Pitting on the cold leg in the sludge pile region

[1] *This mechanism was reported for the first time in the A600TT fleet during the fall of 2019. The indication was reported on a non-high stress tube. Characterizing probe data suggests the presence of significant deposits both within the TSP flow lobes and above/below the TSP. During B2R20 in October 2017, a "soft" chemical cleaning process was applied at Byron Unit 2. This maintenance activity should proactively address this mechanism by removing contaminants which could affect ODSCC initiation.*

3.2.3.b Inspection Strategy Details During B2R20 Inspection for the Degradation Mechanisms Described Above are as Follows:

- All mechanical wear mechanisms – Full-length bobbin inspections of 100% of in-service tubes using qualified techniques were used to detect mechanical wear. In addition, at the TTS where the bobbin probe's detection capabilities are challenged, supplemental array probe testing was used. These exams included full coverage of the tube periphery where the flow velocities and operating experience have shown a greater susceptibility to foreign object wear. The top of tubesheet array (X-Probe™) scope was approximately 55% of all tubes on the hot leg and approximately 8% of all tubes on the cold leg. Bobbin or +Point™[2] probe was used to depth size all detected wear at structures. The +Point™ probe was used to depth and length size all foreign object wear.

- Axial ODSCC at TSP intersections on known high residual stress tubes locations - In addition to a full-length bobbin probe inspection, each of the 39 tubes identified as high residual stress received augmented inspections. Specifically, all hot and cold leg TSP intersections were tested with an X-Probe™.

- Axial ODSCC at tubing dents and dings – Full-length bobbin inspections of 100% of in-service tubes using qualified techniques were used to detect Axial ODSCC at tubing dents and dings up to 5 Volts. In addition, a 50% sample of dents and dings greater than 5 Volts in the hot leg, U-bend and outside the preheater were tested with the +Point™ probe. In the preheater and flow distribution baffle on the hot leg, a 50% sample of dents and dings greater than 2 Volts were tested with the +Point™ probe. Note, the remaining 50% of the population were tested during the prior inspection performed in refueling outage B2R18 (October 2014). In addition, all dents and dings greater than 2 Volts in known high residual stress tubes locations were tested with a +Point™ probe in both B2R20 and B2R18.

- Circumferential and Axial ODSCC and PWSCC at the hot leg TTS expansion transition (including overexpansions) and inside the tubesheet (including bulges) – To detect all SCC mechanisms at the top of tubesheet and inside the tubesheet (to the H* depth) on the Hot leg, a 55% Array (X-Probe™) probe scope was performed (50% of bundle plus 2-3 tube periphery). Note, the same program was implemented at B2R18, thus, the remaining 45% of this population of tubes were tested during the prior inspection performed in refueling outage B2R18.

- Axial PWSCC in small radius U-bends - A 50% sample to detect PWSCC in the Row 1 and Row 2 U-bends with the +Point™ probe was performed. Note, the remaining 50% of the population were tested during the prior inspection performed in refueling outage B2R18.

---

[2] *+Point and X-Probe are trademarks or registered trademarks of Zetec, Inc., its subsidiaries and/or affiliates in the United States of America and may be registered in other countries through the world. All rights reserved. Unauthorized use is strictly prohibited. Other names may be trademarks of their respective owners.*

3.2.3.c Considerations Specific to Alloy 600TT Tubing

- Byron Unit 2 has 39 tubes identified as potentially having high residual stress (HRS) in service.

- Any potentially high residual stress tubes that were not identified by the screening process are tested in the 100% full-length bobbin program every inspection outage. An enhancement to improve the probability of detection for axial ODSCC was added to the inspection program in B2R18 (October 2014) and continued in B2R20 (October 2017) was to require any TSP with a mix residual of 0.4 Vm to be tested with the +Point™ probe. In addition, the possibility for other high stress tubes to be present is considered analytically in the OA. Specifically, for the high stress tube analysis, two OA models are used; an acute initiation model which closely mimics the prior Braidwood history by introducing a discrete quantity of flaws into the model in a short time period, and low Weibull slope model which introduces flaws on a more traditional basis (i.e., spread out over time). The susceptible population size applied for the low Weibull slope model is extremely conservative (i.e., it assumes there are significantly more high stress tubes than the 39, thus this OA model would cover any potential cases of high stress tubes not being in the identified know high stress tube population). An additional conservatism is that for both high stress tube models, the upper bound EPRI SG Integrity Assessment Guidelines (IAGL) (Reference 2) default growth rate was applied. The analysis of axial ODSCC at freespan dings on high residual stress tubes (Braidwood Unit 2 operating experience) is addressed by the low Weibull slope analysis model.

- As discussed previously, in addition to a full-length bobbin probe inspection, each of the 39 tubes identified as high residual stress received augmented inspections. Specifically, all hot and cold leg TSP intersections were tested with an X-Probe™. This combination of bobbin and X-Probe™ testing greatly improves the overall detection performance of the applied inspection program. Furthermore, all dents and dings greater than 2 volts were tested with a +Point™ probe. No crack indications were noted during any inspections performed in B2R18 (October 2014) or in B2R20 (October 2017).

- Axial ODSCC at and just above TSP intersections on non-high residual stress tubes in the presence of heavy deposits and not at a ding or dent was reported for the first time in the A600TT fleet during the fall of 2019. The OA provided in Attachment 5 of this submittal addresses this mechanism and based on analyses using the data from the plant which experienced this degradation. The Byron Unit 2 analysis produces acceptable results for three-cycles of operation. This is based on using the low Weibull slope initiation model and the assumption that the non-high stress tubes would be expected to experience growth rates bounded by the EPRI SG IAGL (Reference 2) typical default value.

3.2.3.d Operational Assessment Summary for All Degradation Mechanisms; Including Predicted Margin to the Tube Integrity Performance Criteria at B2R23 (October 2021):

The technical justification for deferring the B2R22 SG tube examination by one operating cycle for SCC and mechanical wear at structures mechanisms is based on a new OA provided in

Attachment 5 that was performed in accordance with EPRI SG IAGL (Reference 2). This OA supplements the current OA (Reference 5) from the end of operating Cycle 22 condition to the end of operating Cycle 23, thus justifying operation of the SGs for three operating cycles between SG eddy current inspections. The OA provided Attachment 5 will fully support the deferral of the B2R22 SG inspections until the next Unit 2 refueling outage (B2R23) where, for the existing and potential degradation mechanisms:

(1) Structural integrity performance criterion (SIPC) margin requirement of three times normal operating pressure (3xNOPD) on tube burst will be satisfied at B2R23 for the existing and potential degradation, and
(2) Accident-induced leakage performance criteria (AILPC) for the limiting accident condition will be met for the end of Cycle 22 condition.

SG tubing is subject to two types of degradation; existing degradation, or degradation modes previously observed within the Byron Unit 2 SGs, and potential degradation, or degradation modes not yet observed within the Byron Unit 2 SGs but judged to have a meaningful likelihood of occurrence based on operation of similar units or laboratory testing.

To support provide the required technical justification for deferral of the planned SG examinations during B2R22, Attachment 5 provides the OA predictions for all existing structural wear degradation mechanisms and all the potential corrosion degradation mechanisms necessary to justify extended operation of Byron Unit 2 until B2R23 (October 2021). A summary of the methodology and results of the OA analysis are presented below.

<u>Methodology for SCC Mechanisms</u>

These SCC mechanisms were each evaluated by performing full-bundle probabilistic analyses to calculate the probability of tube burst and leakage potential in accordance with Section 8.3 of the EPRI SG IAGL (Reference 2). The probabilistic model included the important input distributions for; material strength properties of the tubing, probability of detection for the eddy current inspection technique, a lognormal crack growth rate model appropriate for each mechanism at T_{Hot}, and the use of a Weibull initiation function predicting when SCC flaws have developed over time. One important feature built into the model is its ability to predict and account for the cumulative effect of a population of newly initiated SCC indications and preexisting undetected SCC indications which were either missed or too small to be detected by the eddy current technique used.

The OA approach was developed based on Braidwood Unit 2 prior operating experience (for high stress tubes) and benchmarking of other Alloy 600TT units which have experienced these SCC mechanisms. Several conservatisms, such as the number of assumed SCC indications present, are factored into the analyses and when required, bounding cases are considered. Discussion of all the inputs, conservatisms and cases evaluated for potential SCC mechanisms for Byron Unit 2 are provided in Attachment 5.

<u>OA Results for SCC Mechanisms</u>

For all mechanisms evaluated in Attachment 5, the probability of burst is less than the limit of 0.05 and the probability of leakage at steam line break conditions exceeding the applied AILPC

limit for Byron Unit 2 of 0.5 gpm is less than the limit of 0.05. Therefore, extending the inspection interval to three-cycles will satisfy the tube integrity requirements of NEI 97-06 (Reference 1) and justifies deferring the B2R22 inspections to B2R23 in October 2021. Table 6, for potential SCC mechanisms for Byron Unit 2, provides a summary of the probabilistic analysis results (i.e., probability of burst and probability of exceeding accident induced leakage criteria) and margin to the tube integrity performance criteria at the next inspection at B2R23 in October 2021, accounting for flaw growth over the 3-cycle operating period.

The following provides additional details about the results provided in Table 6:

- The probability of burst and leakage was computed for two axial ODSCC initiation models in high residual stress (HRS) tubes at tube supports; acute and low slope Weibull, with the acute model being more conservative and providing larger, but still acceptable, POB and POL values. The low slope model also accommodates the potential axial ODSCC cases in non-HRS tubes at tube supports and in the free span at heavy deposits as reported for the first time in the A600TT fleet during the fall of 2019. The OA provided in Attachment 5 addresses this mechanism and based on analyses using the data from the plant which experienced this degradation, the Byron Unit 2 analysis produces acceptable results for three-cycles of operation. This is based on using the low Weibull slope initiation model and the assumption that the non-high stress tubes would be expected to experience growth rates bounded by the EPRI SG IAGL (Reference 2) typical default value.

- For the circumferential and axial ODSCC at TTS expansion cases, the B2R18 probabilities and B2R20 probabilities were combined using a Boolean Sum process.

- The POB and POL probabilities for dings (all voltages) and dents (all voltages) would normally be combined. However, in light of recent operating experience at another Alloy 600TT unit which experienced a large number of axial ODSCC detections at tube supports with dents, it was noted that the frequency of occurrence of short axial OD stress corrosion cracks initiating at larger dents (i.e., those above 9 volts, was significantly higher than at dent locations less than 9 volts in amplitude and at all ding locations). To model this potential condition in the 3-cycle Byron Unit 2 OA, dents in Byron Unit 2 tubes greater than 9 volts were treated as a separate mechanism using the acute (rapid) initiation model. The POB and POL probabilities for the remaining population of dents and dings (i.e., all dings and dents less than 9 volts, were combined using a Boolean Sum process).

- Prior experience has indicated that PWSCC growth rates and length distributions are bounded by the ODSCC growth and length distributions, therefore, the POB and POL for the PWSCC mechanisms on Table 6 are shown as less than the ODSCC at TTS expansion transitions values.

Table 6: Summary of Operational Assessment (Exam Scope, Results, and Margins) for Potential SCC Degradation Mechanisms for 3 Cycle Operation to B2R23 (October 2021)

Mechanism	Probe Type	B2R20 Exam Scope	Probability of Burst	Margin to SIPC	Probability of Leakage Exceeding Accident-Induced Leak Limit	Margin to AILPC Limit	Calculated 95/50 Leakage (gpm)
Axial ODSCC at TSP Intersections: HRS Tubes – Acute Model (5)	Bobbin and X-Probe™	100%	3.74%	1.26%	1.20%	3.8%	0.0100
Axial ODSCC at TSP Intersections: HRS Tubes – Low Weibull Slope Model (Includes Non-HRS Tubes) (5)	Bobbin and X-Probe™	100%	3.18%	1.82%	1.87%	3.13%	0.0427
Circ ODSCC at TTS Expansion Transitions (4)	X-Probe™	55%	0.34%	4.64%	0.03%	4.97%	0.0146
Axial ODSCC at <5V Dings/Dents (4) Axial ODSCC at >5V Dings (4) Axial ODSCC at >5V but <9V Dents (4)	Bobbin +Point™ +Point™	100% 50% 50%	0.76%	4.24%	0.43%	4.57%	0.0082
Axial ODSCC at >9V Dents	+Point™	50%	1.10%	3.90%	0.5%	4.50%	0.0102
Axial ODSCC at TTS Expansion Transitions	X-Probe™	50%	0.30%	4.70%	0.18%	4.82%	~0
Circ PWSCC at TTS Exp. Transitions (1)	X-Probe™	50%	<0.34%	>4.64%	~0%	~5%	~0
Axial PWSCC at TTS Exp. Transitions (1)	X-Probe™	50%	<0.30%	>4.70%	~0%	~5%	~0
PWSCC in Small Radius U-Bends	+Point™	50%	<0.30%	>4.70%	~0%	~5%	~0
Total Summed Leak Rate for All Mechanisms: AILPC Limit = 0.5 gpm							0.0757 (2, 3)

Notes:

(1) PWSCC at TTS is bounded by ODSCC at TTS cases.
(2) Leak rate from axial ODSCC at TSP intersections on high residual stress tubes is taken from the maximum of the two cases. These cases are independent and are not combined.
(3) No primary-to-secondary leakage was reported during Cycle 21 and is not expected for Cycle 22. Therefore, there is no contribution from indications below H*.
(4) Identified probability of burst and leakage and combined by Boolean sum of all contributing sub populations.
(5) Conservative upper bound IAGL default growth rate used; however, the lower typical IAGL default growth rate is believed to be bounding at this location.

Methodology for Mechanical Wear Mechanisms

Fretting wear at tube supports, has also been evaluated in Attachment 5. The number, location and size of these indication was previously reported to the NRC for B2R20 via "Byron Station, Unit 2 Steam Generator Tube Inspections Report for Refueling Outage 20," dated April 5, 2018 (ML18095A116). For all structural wear mechanisms, a deterministic OA strategy was applied using an arithmetic treatment of uncertainties.

Table 7 presents a summary of the analysis parameters and OA results using the largest remaining structural wear flaw left in service for each wear location. A sufficiently large data base for antivibration bar (AVB) wear growth rates indicates that the 95th percentile depth growth rate can be applied. Accounting for 3-cycles of growth, there is still approximately 20% TW of margin before the condition monitoring limit is reached for the deepest AVB wear left in service at B2R20.

For quatrefoil tube support (TSP) and drilled support plate (DSP) wear, the available quantity of growth rate data is not sufficient for development of a depth growth distribution; therefore, the maximum observed growth rate is applied. There are 12 TSP wear indications in the Byron Unit 2 SGs. Accounting for 3-cycles of growth, there is still approximately 4%TW of margin before the condition monitoring limit is reached for the deepest TSP wear left in service at B2R20 if uniform depth (i.e., flat, TSP wear is assumed). Typically, TSP wear is tapered, which provides a larger margin to reaching the CM limit (i.e., ~20%TW). The largest of the 5 DSP wear indications is 26%TW, therefore, accounting for 3-cycles of growth, there is still approximately 16%TW of margin before the condition monitoring limit is reached for the deepest DSP wear left in service at B2R20.

In summary, using the deterministic method, which is considered to be the most conservative OA approach, tubes with any of the three existing structural support mechanical wear mechanisms can safely operate for three cycles (approximately 52 EFPM) until October 2021 without challenging the tube integrity limits for each type of wear.

Table 7: Summary of Input Parameters and OA Results for Mechanical Wear at Structures

	AVB	TSP	DSP
OA Methodology	Deterministic	Deterministic	Deterministic
Uncertainty treatment	Arithmetic	Arithmetic	Arithmetic
Largest indication returned to service after B2R20 (%TW, NDE)	39%TW	34%TW	26%TW
Applicable ETSS	96004.3 r13	96910.1r11	96910.1r11
Bounding degradation growth rate (%TW/EFPY)	2.1	3.2	2.5
Basis for growth rate selection	(Note 1)	(Note 2)	(Note 2)
Projected size at B2R23, 52 EFPM (%TW, NDE)	48%TW	48%TW	37%TW
Bounding degradation geometry	(Note 3)	(Note 3)	(Note 4)
Burst pressure at projected actual B2R23 size (psi)	5741	4545	5773
Condition Monitoring limit at 3xNOPD, 4155 psi (%TW, NDE)	68%TW	52%TW (Flat) 68%TW (Tapered) (Note 5)	53%TW
Approximate margin (%TW)	~20%TW	~4%TW (Flat) ~ 20%TW (Tapered)	~16%TW

Notes:

(1) Basis for selection: 95th percentile of paired AVB wear indications at B2R18 and B2R20 for limiting steam generator.

(2) Basis for selection: largest observed growth rate for paired wear indications at TSP (or DSP). Total population of thirteen TSP paired indications and ten DSP paired indications, for both outages combined.

(3) Volumetric with limited circumferential and axial extent.

(4) Volumetric uniform thinning with limited axial extent.

(5) CM Limit calculated using uniformly deep (i.e., flat, flaw profile. Experience suggests TSP wear will exhibit a tapered profile. For assumed taper angle of 1 degree, the CM limit is 68%TW.

Methodology and OA Results for Mechanical Wear Due to Foreign Objects

During the fall 2017 refueling outage at Byron Unit 2 (B2R20), Foreign Object Search and Retrieval (FOSAR) was performed at the top of the secondary tubesheet in all four SGs and within the preheater region of SG 2B and SG 2C. These inspections identified a small variety of foreign objects and material in the preheater region and at the top of tubesheet. In addition to the foreign objects identified by visual inspections, eddy current inspection identified volumetric wear and possible loose part signal indications near the tube support plates (TSPs) in the upper tube bundle. All new and previous foreign object wear indications including their location and size were previously reported to the NRC for B2R20 via "Byron Station, Unit 2 Steam Generator Tube Inspections Report for Refueling Outage 20," dated April 5, 2018 (ML18095A116).

Before returning from B2R20, a 2-cycle OA covering the potential for future Foreign Object (FO) wear was developed (Reference 5). This assessment addressed the foreign objects identified during the B2R20 FOSAR inspections as well as the newly reported volumetric wear indications in the upper tube bundle. This assessment also addressed foreign objects and upper bundle wear indications known to be remaining in the Byron Unit 2 SGs from previous operating cycles. To support a third operating cycle, this OA was recently revised (Reference 11) using the foreign object evaluation and disposition methodology provided in Attachment 10.

It should be noted that during B2R20, and prior outages, all foreign objects deemed have the potential for causing foreign object wear or that have caused wear were removed from the SGs, when possible. When foreign object removal is not possible, in order to prevent further tube wear, tubes in contact with the foreign object causing active tube wear are preventatively plugged.

To support the deferral of B2R22 SG Inspections, Westinghouse re-assessed the potential for backing bars in the waterbox of the 2C SG to cause tube wear over 3 operating cycles under LTR-CECO-20-043-P, Revision 0, "Engineering Re-Evaluation of Byron Unit 2 Steam Generator 2C Waterbox Cap Plate and Potential Loose Parts in Support of Steam Generator Inspection Deferral for B2R22 (Fall 2020) Outage," (provided in Attachment 8 of this submittal) and determined that all calculated wear times for tubes remaining in-service were shown to be in excess of four full operational cycles following B2R20 should the backing bars become lodged anywhere within the tube bundle. Therefore, no inspection or remedial actions is recommended by Westinghouse for the B2R22 outage.

In summary, the result of the revised foreign object OAs (Reference 11 and Attachment 8), which are based on the evaluation of the remaining foreign objects identified in B2R20 and potential new ones, including the possible release of waterbox backing bars in SG 2C, concludes that they will not cause tube wear sufficient to degrade tube structural or leakage integrity to below acceptance criteria for at least three cycles at current operating conditions. Since the SG inspection in B2R20, there have been no documented foreign object intrusions into the SGs or Feedwater system at Byron Unit 2.

3.2.4 Mitigating Strategies

The normal Mode 1 (Power Operation) requirement under the EPRI Steam Generator PWR Primary-to-Secondary Leak Guidelines (Reference 10) state that Action Level 1 is reached at a leakage rate of 30 gallons per day (gpd.) However, the guidelines require a site to enter an "Increased Monitoring" condition when total primary-to-secondary leakage is detected to be equal to or greater than 5 gpd. After entering the increased monitoring condition, radiation monitors alert/alarm set points are reset, as necessary, to above their existing baseline reading (but not over 30 gpd) to permit detection of rapidly increasing leakage.

EGC procedure CY-AP-120-340, "Primary-to-Secondary Leak Program," (Reference 6) currently in effect has lower administrative limits on Primary-to-Secondary leakage in order to ensure Byron Unit 2 is prepared to quickly respond should the leakage rate increase. Steam Generator Management Program Monitoring condition is entered when normal radiochemical grab sampling and process radiation monitors indicate leakage of greater than or equal to 3 gpd. This describes the condition in which leakage has been detected and quantified and is greater than or equal to 3 gpd but is not in a range that can be accurately monitored by most radiation monitors. When this occurs, Engineering is notified, and the appropriate Corrective Action Processes are initiated to document and track the excursion. The activities when this condition is entered are described in EGC procedure ER-AP-420-0051, "Conduct of Steam Generator Management Program Activities." (Reference 7)

When operational leakage is equal to or greater than 3 gpd is confirmed during the operating period between inspections, at the next outage, in situ pressure testing, tube pull, or analysis should be performed to quantify the expected accident leak rate to assess compliance with accident leakage performance criteria. In addition, prior to entering an outage, an action plan is developed to address means of identifying the defective tube(s), flowchart sampling methods to bound the defect and provide reasonable assurance that unit restart is prudent.

During the extended operating cycle from B2R22 to B2R23, Byron Unit 2 will lower its normal 100 gpd shutdown criteria for primary-to-secondary leakage down to 30 gpd for confirmed and sustained leakage at or above that level. This action will provide more margin by requiring shutdown at a lower leakage level, thereby lowering the likelihood of a steam generator tube burst.

Byron Unit 2 maintains a Loose Parts Detection System on the Steam Generators that monitors for activity on the primary side of the Hot Leg and Cold Leg. Currently, all 8 monitoring channels are operating. Should a loose part be present in the hot leg or cold leg primary bowl during operating Cycle 22, Byron Unit 2 will take appropriate action to minimize any damage to the Steam Generators.

4.0 REGULATORY ANALYSIS

4.1 Applicable Regulatory Requirements/Criteria

Section 182a of the Atomic Energy Act requires applicants for nuclear power plant operating licenses to include technical specifications as part of the license. The Commission's regulatory requirements related to the content of the technical specifications are contained in Title 10, Code of Federal Regulations (10 CFR), Section 50.36, "Technical Specifications," of 10 CFR Part 50 "Domestic Licensing of Production and Utilization Facilities." The Technical Specification requirements in 10 CFR 50.36 include the following categories: (1) safety limits, limiting safety systems settings and control settings, (2) limiting conditions for operation, (3) surveillance requirements, (4) design features, and (5) administrative controls. As required by 10 CFR 50.36(c)(5), administrative controls are the provisions relating to organization and management, procedure, recordkeeping, review and audit, and reporting necessary to assure operation of the facility in a safe manner.

For Byron Unit 2, SG integrity is maintained by meeting the performance criteria specified in Byron TS 5.5.9, "Steam Generator (SG) Program," for structural and leakage integrity, consistent with the Byron Updated Final Safety Analysis Report (UFSAR), Section 5.4.2. In addition, Byron TS 3.4.13, "RCS Operational LEAKAGE," requires a limit on operational primary-to-secondary leakage, beyond which the plant must be shut down. Byron TS 3.4.19, "Steam Generator (SG) Tube Integrity," requires that SG tube integrity be maintained and all SG tubes satisfying the tube plugging criteria shall be plugged in accordance with the SG Program. Should an existing flaw that exceeds the tube integrity repair limit not be detected during the periodic tube surveillance required by the plant TS, the operational leakage limit provides added assurance of timely plant shutdown before tube structural and leakage integrity are impaired.

The proposed one-time revision to TS 5.5.9 to defer the SG inspection to be performed after three operating cycles following refueling outage B2R20 does not alter Byron Unit 2 compliance with the referenced TS LCOs or the requirements of 10 CFR 50.36.

As stated in 10 CFR 50.59(c)(1)(i), a licensee is required to submit a license amendment pursuant to 10 CFR 50.90 if a change to the technical specifications is required. Furthermore, the requirements of 10 CFR 50.59 necessitate that the NRC approve technical specification changes before the changes are implemented. EGC's submittal meets the requirements of 10 CFR 50.59(c)(1)(i) and 10 CFR 50.90.

General Design Criterion (GDC) 14, "Reactor Coolant Pressure Boundary (RCPB)," of Appendix A "General Design Criteria for Nuclear Power Plants," to 10 CFR Part 50 requires, among other things, that 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 of gross rupture. The proposed change continues to provide steam generator tube inspections that will contribute to a robust RCPB.

GDC 15, "Reactor Coolant System (RCS) 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. The proposed

change does not negatively impact steam generator tube integrity during normal operation or anticipated operational occurrences.

GDC 30, "Quality of reactor coolant pressure boundary," requires that components which are part of the RCPB shall be designed, fabricated, erected, and tested to the highest quality standards practical. The proposed change does not reduce quality standards for steam generator design, fabrication, or testing.

GDC 31, "Fracture prevention of reactor coolant pressure boundary," requires the RCPB 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 proposed change does not alter the fracture prevention design of the steam generator tubes.

GDC 32, "Inspection of reactor coolant pressure boundary," the steam generator tubes are designed to permit periodic inspection and testing to assess their structural and leaktight integrity. The proposed change does not eliminate periodic inspection or testing of the steam generator tubes.

EGC also analyzed the consequences of postulated design basis accidents (DBAs), such as a SG tube rupture and a steam line break. These analyses consider primary-to-secondary leakage that may occur during these events and must show that the offsite radiological consequences do not exceed the applicable limits of 10 CFR 50.67, "Accident source term," or 10 CFR 100.11, "Determination of exclusion area, low population zone, and population center distance," for offsite doses; GDC 19 for control room operator doses (or some fraction thereof as appropriate to the accident); or the NRC-approved licensing basis (e.g., a small fraction of these limits). No accident analyses for Byron are being changed because of the proposed amendments, and therefore, no radiological consequences of any accident analysis are being changed. The proposed change maintains the accident analyses and consequences that the NRC has reviewed and approved for the postulated DBAs for SG tubes.

EGC has reviewed the basis for conformance to these GDC, as described in the Byron Station UFSAR and has concluded that the proposed one-time revision to defer the Byron Unit 2 Steam Generator inspection to be performed after three operating cycles following refueling outage B2R20 remains in conformance with all requirements.

4.2 <u>No Significant Hazards Consideration</u>

Exelon Generation Company, LLC (EGC) requests amendments to the Technical Specifications (TS) for Renewed Facility License Nos. NPF-37 and NPF-66 for Byron Station, Units 1 and 2 (Byron).

This proposed amendment request revises TS 5.5.9, "Steam Generator (SG) Program," for a one-time revision to the frequency for SG tube inspections. The requested TS amendments support deferral of the TS required inspections until the next Unit 2 refueling outage, which is scheduled in spring 2022 (B2R23).

EGC has evaluated the proposed change against the criteria of 10 CFR 50.92(c) criteria to determine if the proposed change results in any significant hazards. The following is the evaluation of each of the 10 CFR 50.92(c) criteria:

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

   Response: No.

   The proposed one-time change will defer the SG inspection to be performed after three operating cycles. This change does not physically change the SGs, the plant, or the way the SGs or plant are operated. This change also does not change the design of the SG. Inspection frequencies and inspection activities are not an initiator to a SG tube rupture accident, or any other accident previously evaluated. As a result, the probability of an accident previously evaluated is not significantly increased. The SG tubes inspected by the SG Program continue to be required to meet the SG Program performance criteria and to be capable of performing any functions assumed in the accident analysis. As a result, the consequences of any accident previously evaluated are not significantly increased.

   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.

   The proposed one-time change will defer the SG inspection to be performed after three operating cycles. The proposed change does not alter the design function or operation of the SGs or the ability of an SG to perform its design function. The SG tubes continue to be required to meet the SG Program performance criteria. An analysis has been performed which evaluates all credible failure modes. This analysis resulted in no new or different kind of accident then has been previously evaluated. The proposed change does not create the possibility of a new or different kind of accident due to credible new failure mechanisms, malfunctions, or accident initiators that not considered in the design and licensing bases.

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

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

   Response: No.

   The proposed one-time change will defer the SG inspection to be performed after three operating cycles. The proposed change does not change any of the controlling values of parameters used to avoid exceeding regulatory or licensing limits. The proposed

change does not affect a design basis or safety limit, or any controlling value for a parameter established in the UFSAR or the license.

Therefore, the proposed change does not involve a significant reduction in a margin of safety.

Based on the above, EGC concludes that the proposed amendments do 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.

4.3 Precedent

The following precedent applies to the Byron Unit 2 application for a one-time deferral of the Steam Generator Inspections:

- Letter from J. S. Wiebe (U.S. Nuclear Regulatory Commission) to B. C. Hanson (Exelon Generation Company, LLC), "Braidwood Station, Unit 2 – Issuance of Amendment No. 209 RE: One-Time Extension of Steam Generator Inspections [COVID-19] (EPID L-2020-LLA-0069)," dated May 1, 2020 (ML20111A000) (Reference 8)

- Letter from D. J. Galvin (U.S. Nuclear Regulatory Commission) to K. J. Peters (Vistra Operations Company LLC), "Comanche Peak Nuclear Power Plant, Unit Nos. 1 and 2 – Issuance of Amendment Nos. 173 and 173 Regarding Revision to Technical Specification 5.5.9, 'Unit 1 Model D76 and Unit 2 Model Steam Generator (SG) Program' (Exigent Circumstances) (EPID L-2020-LLA-0072)," dated April 17, 2020 (ML20108E878) (Reference 9)

4.4 Conclusion

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 amendments will not be inimical to the common defense and security or to the health and safety of the public.

5.0 ENVIRONMENTAL CONSIDERATION

EGC has determined that the proposed amendments would change requirements 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 amendments do not involve (i) a significant hazards consideration, (ii) a significant change in the types or a 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 change 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 amendments.

6.0 REFERENCES

1. Nuclear Energy Institute (NEI) 97-06, Revision 3, "Steam Generator Program Guidelines," January 2011

2. Electric Power Research Institute (EPRI) Report 3002007571, "Steam Generator Management Program: Steam Generator Integrity Assessment Guidelines," Revision 4, June 2016

3. EC 619170, B2R20 Degradation Assessment dated September 29, 2017

4. B2R20 180 day report, "Byron Station, Unit 2 Steam Generator Tube Inspection Report for Refueling Outage 20," dated April 5, 2018 (ML18095A116)

5. EC 620886, "Final Condition Monitoring and Operational Assessment, Including Foreign Object Evaluation," dated October 2017

6. CY-AP-120-340, "Primary-to-Secondary Leak Program," Revision 10

7. ER-AP-420-0051, "Conduct of Steam Generator Management Program Activities," Revision 23

8. Letter from J. S. Wiebe (U.S. Nuclear Regulatory Commission) to B. C. Hanson (Exelon Generation Company, LLC), "Braidwood Station, Unit 2 – Issuance of Amendment No. 209 RE: One-Time Extension of Steam Generator Inspections [COVID-19] (EPID L-2020-LLA-0069)," dated May 1, 2020 (ML20111A000)

9. Letter from D. J. Galvin (U.S. Nuclear Regulatory Commission) to K. J. Peters (Vistra Operations Company LLC), "Comanche Peak Nuclear Power Plant, Unit Nos. 1 and 2 – Issuance of Amendment Nos. 173 and 173 Regarding Revision to Technical Specification 5.5.9, 'Unit 1 Model D76 and Unit 2 Model Steam Generator (SG) Program' (Exigent Circumstances) (EPID L-2020-LLA-0072)," dated April 17, 2020 (ML20108E878)

10. EPRI Steam Generator Management Program: PWR Primary-to-Secondary Leak Guidelines, Revision 4, Report 1022832, dated November 2011

11. EC 632009 Rev. 0, "Foreign Object Operational Assessment to Support B2R22 Deferral LAR," dated July 2020

ATTACHMENT 2

Byron Station, Units 1 and 2

NRC Docket Nos. STN 50-454 and STN 50-455

Proposed Technical Specifications Change (Mark-Up)

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

potentially be occurring at this location divided by the total number of times the SG is scheduled to be inspected in the inspection period. Each inspection period defined below may be extended up to 3 effective full power months to include a SG inspection outage in an inspection period and the subsequent inspection period begins at the conclusion of the included SG inspection outage.

a) After the first refueling outage following SG installation, inspect 100% of the tubes during the next 144 effective full power months. This constitutes the first inspection period;

b) During the next 120 effective full power months, inspect 100% of the tubes. This constitutes the second inspection period;

c) During the next 96 effective full power months, inspect 100% of the tubes. This constitutes the third inspection period; and

d) During the remaining life of the SGs, inspect 100% of the tubes every 72 effective full power months. This constitutes the fourth and subsequent inspection periods.

with the exception that each SG is to be inspected during the third refueling outage in B2R23 following inspections completed in refueling outage B2R20

3. For Unit 2, after the first refueling outage following SG installation, inspect each SG at least every 48 effective full power months or at least every other refueling outage (whichever results in more frequent inspections). In addition, the minimum number of tubes inspected at each scheduled inspection shall be the number of tubes in all SGs divided by the number of SG inspection outages scheduled in each inspection period as defined in a, b, and c below. If a degradation assessment indicates the potential for a type of degradation to occur at a location not previously inspected with a technique capable of detecting this type of degradation at this location and that may satisfy the applicable tube plugging criteria, the minimum number of locations inspected with such a capable inspection technique during the remainder of the inspection period may be prorated. The fraction of locations to be inspected for this potential type of degradation at this location at the end of the inspection period shall be no less than the ratio of the number of times the SG is scheduled to be

ATTACHMENT 3

Byron Station, Units 1 and 2

NRC Docket Nos. STN 50-454 and STN 50-455

Revised Technical Specifications Pages (Clean)

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

2. Accident induced leakage performance criterion: The primary to secondary accident induced leakage rate for any design basis accident, other than a SG tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all SGs and leakage rate for an individual SG. Leakage is not to exceed a total of 1 gpm for all SGs.

3. The operational LEAKAGE performance criteria is specified in LCO 3.4.13, "RCS Operational LEAKAGE."

c. Provisions for SG tube plugging criteria. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal wall thickness shall be plugged. The following alternate tube plugging criteria shall be applied as an alternative to the 40% depth based criteria:

For Unit 2, tubes with service-induced flaws located greater than 14.01 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 14.01 inches below the top of the tubesheet shall be plugged upon detection.

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 plugging criteria. For Unit 2, portions of the tube below 14.01 inches from the top of the tubesheet are excluded from this requirement.

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements of d.1, d.2, and d.3 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. A degradation assessment 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 installation.

2. For Unit 1, after the first refueling outage following SG installation, inspect each SG at least every 72 effective full power months or at least every third refueling outage (whichever results in more frequent inspections). In addition, the minimum number of tubes inspected at each scheduled inspection shall be the number of tubes in all SGs divided by the number of SG inspection outages scheduled in each inspection period as defined in a, b, c, and d below. If a degradation assessment indicates the potential for a type of degradation to occur at a location not previously inspected with a technique capable of detecting this type of degradation at this location and that may satisfy the applicable tube plugging criteria, the minimum number of locations inspected with such a capable inspection technique during the remainder of the inspection period may be prorated. The fraction of locations to be inspected for this potential type of degradation at this location at the end of the inspection period shall be no less than the ratio of the number of times the SG is scheduled to be inspected in the inspection period after the determination that a new form of degradation could potentially be occurring at this location divided by the total number of times the SG is scheduled to be inspected in the inspection period. Each inspection period defined below may be extended up to 3 effective full power months to include a SG inspection outage in an inspection period and the subsequent inspection period begins at the conclusion of the included SG inspection outage.

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

a) After the first refueling outage following SG installation, inspect 100% of the tubes during the next 144 effective full power months. This constitutes the first inspection period;

b) During the next 120 effective full power months, inspect 100% of the tubes. This constitutes the second inspection period;

c) During the next 96 effective full power months, inspect 100% of the tubes. This constitutes the third inspection period; and

d) During the remaining life of the SGs, inspect 100% of the tubes every 72 effective full power months. This constitutes the fourth and subsequent inspection periods.

3. For Unit 2, after the first refueling outage following SG installation, inspect each SG at least every 48 effective full power months or at least every other refueling outage (whichever results in more frequent inspections) with the exception that each SG is to be inspected during the third refueling outage in B2R23 following inspections completed in refueling outage B2R20. In addition, the minimum number of tubes inspected at each scheduled inspection shall be the number of tubes in all SGs divided by the number of SG inspection outages scheduled in each inspection period as defined in a, b, and c below. If a degradation assessment indicates the potential for a type of degradation to occur at a location not previously inspected with a technique capable of detecting this type of degradation at this location and that may satisfy the applicable tube plugging criteria, the minimum number of locations inspected with such a capable inspection technique during the remainder of the inspection period may be prorated. The fraction of locations to be inspected for this potential type of degradation at this location at the end of the inspection period shall be no less than the ratio of the number of times the SG is scheduled to be