UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

May 25, 2018

Mr. Ernest J. Kapopoulos, Jr.
Site Vice President
H. B. Robinson Steam Electric Plant
Duke Energy Progress, LLC
3581 West Entrance Road, RNPA01
Hartsville, SC 29550

SUBJECT: H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2 – ISSUANCE OF AMENDMENT 258 REGARDING REQUEST TO REVISE TECHNICAL SPECIFICATION SURVEILLANCE REQUIREMENT FREQUENCIES TO SUPPORT 24-MONTH FUEL CYCLES (CAC NO. MF9544; EPID L-2017-LLA-0206)

Dear Mr. Kapopoulos:

The U.S. Nuclear Regulatory Commission (the Commission) has issued the enclosed Amendment No. 258 to Renewed Facility Operating License No. DPR-23 for the H. B. Robinson Steam Electric Plant, Unit No. 2 (HBRSEP). This amendment consists of changes to the Technical Specifications (TSs) in response to your application dated April 3, 2017, as supplemented by letters dated April 3, May 2, and September 28, 2017 and January 8, 2018.

The amendment revises the TSs for HBRSEP to support operation with 24-month fuel cycles. Specifically, the change would revise the frequency of certain TS Surveillance Requirements from "18 months" to "24 months," in accordance with the guidance of Generic Letter 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle." The amendment reflects the list of TSs to be revised in the April 3, 2017, letter as modified by the May 2, 2017, letter.

A copy of the related Safety Evaluation is enclosed. Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,

Dennis J. Galvin

Dennis J. Galvin, Project Manager
Plant Licensing Branch II-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-261

Enclosures:
1. Amendment No. 258 to DPR-23
2. Safety Evaluation

cc: Listserv

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

DUKE ENERGY PROGRESS, LLC

DOCKET NO. 50-261

H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 258
Renewed License No. DPR-23

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by Duke Energy Progress, LLC (the licensee) (previously Duke Energy Progress, Inc.), dated April 3, 2017, as supplemented by letters dated April 3, May 2, and September 28, 2017, and January 8, 2018, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications, as indicated in the attachment to this license amendment. Paragraph 3.B. of Renewed Facility Operating License No. DPR-23 is hereby amended to read as follows:

   B. Technical Specifications

   The Technical Specifications contained in Appendix A, as revised through Amendment No. 258 are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of its date of issuance and shall be implemented within 120 days from the end of the next refueling outage. Implementation shall include the replacement of the pressure switches as stated in Attachment 5 of the application for the amendment, as supplemented.

FOR THE NUCLEAR REGULATORY COMMISSION

Brian W. Tindell

Brian W. Tindell, Acting Chief
Plant Licensing Branch II-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Renewed License
and the Technical Specifications

Date of Issuance: May 25, 2018

ATTACHMENT TO LICENSE AMENDMENT NO. 258

H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2

RENEWED FACILITY OPERATING LICENSE NO. DPR-23

DOCKET NO. 50-261

Replace page 3 of Renewed Facility Operating License No. DPR-23 with the attached page 3.

Replace the following pages of the Appendix A Technical Specifications with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Remove Pages	Insert Pages	Remove Pages	Insert Pages
3.1-18	3.1-18	3.6-21	3.6-21
3.3-11	3.3-11	3.7-12	3.7-12
3.3-12	3.3-12	3.7-13	3.7-13
3.3-24	3.3-24	3.7-17	3.7-17
3.3-31	3.3-31	3.7-19	3.7-19
3.3-34	3.3-34	3.7-20	3.7-20
3.3-36	3.3-36	3.7-24	3.7-24
3.3-38	3.3-38	3.7-27	3.7-27
3.3-46	3.3-46	3.7-29	3.7-29
3.4-2	3.4-2	3.8-6	3.8-6
3.4-22	3.4-22	3.8-7	3.8-7
3.4-28	3.4-28	3.8-8	3.8-8
3.4-34	3.4-34	3.8-9	3.8-9
3.4-39	3.4-39	3.8-10	3.8-10
3.4-40	3.4-40	3.8-11	3.8-11
3.4-44	3.4-44	3.8-12	3.8-12
3.4-51	3.4-51	3.8-20	3.8-20
3.5-6	3.5-6	3.8-34	3.8-34
3.6-11	3.6-11	3.9-3a	3.9-3a
3.6-12	3.6-12	3.9-5	3.9-5
3.6-17	3.6-17	5.0-15	5.0-15
3.6-19	3.6-19	5.0-22a	5.0-22a

D. Pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess, and use in amounts as required any byproduct, source, or special nuclear material without restriction to chemical or physical form for sample analysis or instrument and equipment calibration or associated with radioactive apparatus or components;

E. Pursuant to the Act and 10 CFR Parts 30 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by operation of the facility.

3. This renewed license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations: 10 CFR Part 20, Section 30.34 of 10 CFR Part 30, Section 40.41 of 10 CFR Part 40, Section 50.54 and 50.59 of 10 CFR Part 50, and Section 70.32 of 10 CFR Part 70; and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

A. Maximum Power Level

The licensee is authorized to operate the facility at a steady state reactor core power level not in excess of 2339 megawatts thermal.

B. Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 258 are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

(1) For Surveillance Requirements (SRs) that are new in Amendment 176 to Final Operating License DPR-23, the first performance is due at the end of the first surveillance interval that begins at implementation of Amendment 176. For SRs that existed prior to Amendment 176, including SRs with modified acceptance criteria and SRs whose frequency of performance is being extended, the first performance is due at the end of the first surveillance interval that begins on the date the Surveillance was last performed prior to implementation of Amendment 176.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.7.1	Perform CHANNEL CALIBRATION of the ARPI System.	24 months

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.9	----------NOTE---------- Verification of setpoint is not required. ---------- Perform TADOT.	92 days
SR 3.3.1.10	----------NOTE---------- This Surveillance shall include verification that the time constants are adjusted to the prescribed values where applicable. ---------- Perform CHANNEL CALIBRATION.	24 months
SR 3.3.1.11	----------NOTE---------- Neutron detectors are excluded from CHANNEL CALIBRATION. ---------- Perform CHANNEL CALIBRATION.	24 months
SR 3.3.1.12	----------NOTE---------- This Surveillance shall include verification that the electronic dynamic compensation time constants are set at the required values, and verification of RTD response time constants. ---------- Perform CHANNEL CALIBRATION.	24 months
SR 3.3.1.13	Perform COT.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.14	----------NOTE---------- Verification of setpoint is not required. ---------- Perform TADOT.	 24 months
SR 3.3.1.15	----------NOTE---------- Verification of setpoint is not required. ---------- Perform TADOT.	-------NOTE-------- Only required when not performed within previous 31 days ---------- Prior to reactor startup

SURVEILLANCE REQUIREMENTS

----------NOTES----------

1. Refer to Table 3.3.2-1 to determine which SRs apply for each ESFAS Function.

2. When a channel or train is placed in an inoperable status solely for the performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the redundant train is OPERABLE.

SURVEILLANCE		FREQUENCY
SR 3.3.2.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.2.2	Perform ACTUATION LOGIC TEST.	31 days on a STAGGERED TEST BASIS
SR 3.3.2.3	Perform MASTER RELAY TEST.	24 months
SR 3.3.2.4	Perform COT.	92 days
SR 3.3.2.5	Perform SLAVE RELAY TEST.	24 months
SR 3.3.2.6	----------NOTE---------- Verification of setpoint not required for manual initiation functions. ---------- Perform TADOT.	 24 months
SR 3.3.2.7	Perform CHANNEL CALIBRATION.	24 months

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
G. As required by Required Action E.1 and referenced in Table 3.3.3-1.	G.1 Initiate action in accordance with Specification 5.6.6.	Immediately

SURVEILLANCE REQUIREMENTS

----------NOTE----------
SR 3.3.3.1 and SR 3.3.3.2 apply to each PAM instrumentation Function in Table 3.3.3-1; except Functions 9, 22, 23, and 24. SR 3.3.3.3 applies only to Functions 9, 22, 23, and 24.

SURVEILLANCE		FREQUENCY
SR 3.3.3.1	Perform CHANNEL CHECK for each required instrumentation channel that is normally energized.	31 days
SR 3.3.3.2	----------NOTE---------- Neutron detectors are excluded from CHANNEL CALIBRATION. --- Perform CHANNEL CALIBRATION.	24 months
SR 3.3.3.3	----------NOTE---------- Verification of setpoint not required. --- Perform TADOT.	24 months

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.4.1	Perform CHANNEL CHECK for each required instrumentation channel that is normally energized.	31 days
SR 3.3.4.2	Verify each required control circuit and transfer switch is capable of performing the intended function.	18 months
SR 3.3.4.3	----------NOTE---------- Neutron detectors are excluded from CHANNEL CALIBRATION. ---------- Perform CHANNEL CALIBRATION for each required instrumentation channel.	24 months
SR 3.3.4.4	Perform TADOT of the reactor trip breaker open/closed indication.	18 months

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time not met.	D.1 Enter applicable Condition(s) and Required Action(s) for the associated DG made inoperable by LOP DG start instrumentation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.5.1	----------NOTE---------- Verification of setpoint not required. ---------- Perform TADOT.	24 months
SR 3.3.5.2	Perform CHANNEL CALIBRATION with Trip Setpoints as follows: a. Loss of voltage Trip Setpoint of 328 V ± 10% with a time delay of ≤1 second (at zero voltage). b. Degraded voltage Trip Setpoint of 430 V ± 4 V with a time delay of 10 ± 0.5 seconds.	24 months

SURVEILLANCE REQUIREMENTS

----------NOTE----------
Refer to Table 3.3.6-1 to determine which SRs apply for each Containment Ventilation Isolation Function.

SURVEILLANCE		FREQUENCY
SR 3.3.6.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.6.2	Perform ACTUATION LOGIC TEST.	31 days on a STAGGERED TEST BASIS
SR 3.3.6.3	Perform MASTER RELAY TEST.	24 months
SR 3.3.6.4	Perform COT.	92 days
SR 3.3.6.5	Perform SLAVE RELAY TEST.	24 months
SR 3.3.6.6	----------NOTE---------- Verification of setpoint is not required. ---------- Perform TADOT.	24 months
SR 3.3.6.7	Perform CHANNEL CALIBRATION.	24 months

SURVEILLANCE REQUIREMENTS

----------NOTE----------
Refer to Table 3.3.8-1 to determine which SRs apply for each AFW Function.

SURVEILLANCE		FREQUENCY
SR 3.3.8.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.8.2	Perform COT.	92 days
SR 3.3.8.3	----------NOTE---------- For Function 5, the TADOT shall include injection of a simulated or actual signal to verify channel OPERABILITY. --- Perform TADOT.	24 months
SR 3.3.8.4	Perform CHANNEL CALIBRATION.	24 months

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.1.1	Verify pressurizer pressure is greater than or equal to the limit specified in the COLR.	12 hours
SR 3.4.1.2	Verify RCS average temperature is less than or equal to the limit specified in the COLR.	12 hours
SR 3.4.1.3	Verify RCS total flow rate is ≥ 97.3 x 10^6 lbm/hr and greater than or equal to the limit specified in the COLR.	12 hours
SR 3.4.1.4	----------NOTE---------- Not required to be performed until 24 hours after ≥ 90% RTP. ---------- Verify by precision heat balance that RCS total flow rate is ≥ 97.3 x 10^6 lbm/hr and greater than or equal to the limit specified in the COLR.	24 months

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time of Condition B or C not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.9.1	Verify pressurizer water level is within limits.	12 hours
SR 3.4.9.2	Verify capacity of required pressurizer heaters is ≥ 125 kW.	24 months
SR 3.4.9.3	Verify required pressurizer heaters are capable of being powered from an emergency power supply.	24 months

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.11.2	----------NOTE---------- Not required to be performed until 12 hours after entry into MODE 3. ---------- Perform a complete cycle of each PORV.	24 months
SR 3.4.11.3	Perform a complete cycle of each solenoid air control valve and check valve on the nitrogen accumulators in PORV control systems.	24 months
SR 3.4.11.4	Verify accumulators are capable of operating PORVs through a complete cycle.	24 months

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.12.6	---------- NOTE---------- Not required to be performed until 12 hours after decreasing RCS cold leg temperature to ≤ 350°F. ---------- Perform a COT on each required PORV, excluding actuation.	31 days
SR 3.4.12.7	Perform CHANNEL CALIBRATION for each required PORV actuation channel.	24 months

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.14.1	----------NOTES---------- 1. Not required to be performed in MODES 3 and 4. 2. Not required to be performed on the RCS PIVs located in the RHR flow path when in the shutdown cooling mode of operation. 3. RCS PIVs actuated during the performance of this Surveillance are not required to be tested more than once if a repetitive testing loop cannot be avoided. ----------	
	Verify leakage from each RCS PIV is less than or equal to an equivalent of 5 gpm at an RCS pressure ≥ 2235 psig, and verify the margin between the results of the previous leak rate test and the 5 gpm limit has not been reduced by ≥ 50% for valves with leakage rates > 1.0 gpm.	In accordance with the Inservice Testing Program and 24 months AND Prior to entering MODE 2 whenever the unit has been in MODE 5 for 7 days or more, if leakage testing has not been performed in the previous 9 months AND (continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.14.1 (continued)		Within 24 hours following valve actuation due to automatic or manual action or flow through the valve
SR 3.4.14.2	Verify RHR System interlock prevents the valves from being opened with a simulated or actual RCS pressure signal > 474 psig.	24 months

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.15.2	Perform COT of the required containment atmosphere radioactivity monitor.	92 days
SR 3.4.15.3	Perform CHANNEL CALIBRATION of the required containment sump monitor.	24 months
SR 3.4.15.4	Perform CHANNEL CALIBRATION of the required containment atmosphere radioactivity monitor.	24 months
SR 3.4.15.5	Perform CHANNEL CALIBRATION of the required containment fan cooler condensate flow rate monitor.	24 months

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.17.1	Verify seal injection flow of ≥ 6 gpm to each RCP.	12 hours
SR 3.4.17.2	Verify seal injection flow of ≥ 6 gpm to each RCP from each Makeup Water Pathway from the RWST.	24 months
SR 3.4.17.3	For Makeup Water Pathways from the RWST to be OPERABLE, SR 3.5.4.2 is applicable.	In accordance with SR 3.5.4.2

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.2.3	Verify each ECCS pump's developed head at the test flow point is greater than or equal to the required developed head.	In accordance with the Inservice Testing Program
SR 3.5.2.4	Verify each ECCS automatic valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	24 months
SR 3.5.2.5	Verify each ECCS pump starts automatically on an actual or simulated actuation signal.	24 months
SR 3.5.2.6	Verify, by visual inspection, the ECCS containment sump suction inlet is not restricted by debris and the suction inlet strainers show no evidence of structural distress or abnormal corrosion.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.3.2	----------NOTE---------- Valves and blind flanges in high radiation areas may be verified by use of administrative controls. ---------- Verify each containment isolation manual valve and blind flange that is located outside containment and not locked, sealed or otherwise secured and required to be closed during accident conditions is closed, except for containment isolation valves that are open under administrative controls.	31 days for containment isolation manual valves (except Penetration Pressurization System valves with a diameter ≤ 3/8 inch) and blind flanges AND 24 months for Penetration Pressurization System valves with a diameter ≤ 3/8 inch
SR 3.6.3.3	----------NOTE---------- Valves and blind flanges in high radiation areas may be verified by use of administrative means. ---------- Verify each containment isolation manual valve and blind flange that is located inside containment and not locked, sealed or otherwise secured and required to be closed during accident conditions is closed, except for containment isolation valves that are open under administrative controls.	Prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.3.4	Verify the isolation time of each automatic power operated containment isolation valve is within limits.	In accordance with the Inservice Testing Program
SR 3.6.3.5	Verify each automatic containment isolation valve that is not locked, sealed or otherwise secured in position, actuates to the isolation position on an actual or simulated actuation signal.	24 months
SR 3.6.3.6	Verify each 42 inch inboard containment purge valve is blocked to restrict the valve from opening > 70°.	24 months

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.6.2	Operate each containment cooling train fan unit for ≥ 15 minutes.	31 days
SR 3.6.6.3	Verify cooling water flow rate to each cooling unit is ≥ 750 gpm.	31 days
SR 3.6.6.4	Verify each containment spray pump's developed head at the flow test point is greater than or equal to the required developed head.	In accordance with the Inservice Testing Program
SR 3.6.6.5	Verify each automatic containment spray valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	24 months
SR 3.6.6.6	Verify each containment spray pump starts automatically on an actual or simulated actuation signal.	24 months
SR 3.6.6.7	Verify each containment cooling train starts automatically on an actual or simulated actuation signal.	24 months
SR 3.6.6.8	Verify each spray nozzle is unobstructed.	Following activities which could result in nozzle blockage

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.7.1	Verify each spray additive manual, power operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position.	31 days
SR 3.6.7.2	Verify spray additive tank solution volume is ≥ 2505 gal.	184 days
SR 3.6.7.3	Verify spray additive tank NaOH solution concentration is ≥ 30% by weight.	184 days
SR 3.6.7.4	Verify each spray additive automatic valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	24 months

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.8.3	Verify the opening time of each air operated header injection valve is within limits.	In accordance with the Inservice Testing Program
SR 3.6.8.4	Verify each automatic valve in the IVSW System actuates to the correct position on an actual or simulated actuation signal.	24 months
SR 3.6.8.5	Verify the IVSW dedicated nitrogen bottles will pressurize the IVSW tank to ≥ 46.2 psig.	24 months
SR 3.6.8.6	Verify total IVSW seal header flow rate is ≤ 124 cc/minute	24 months

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.4.1	Verify each AFW manual, power operated, and automatic valve in each water flow path, and in the steam supply flow path to the steam driven AFW pump, that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days
SR 3.7.4.2	----------NOTE---------- Not required to be performed for the steam driven AFW pump until 24 hours after ≥ 1000 psig in the steam generator. ---------- Verify the developed head of each AFW pump at the flow test point is greater than or equal to the required developed head.	31 days on a STAGGERED TEST BASIS
SR 3.7.4.3	----------NOTE---------- Not applicable in MODE 4 when steam generator is being used for heat removal. ---------- Verify each AFW automatic valve that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.7.4.4	----------NOTES---------- 1. Not required to be performed for the steam driven AFW pump until 24 hours after ≥ 1000 psig in the steam generator. 2. Not applicable in MODE 4 when steam generator is being used for heat removal. ---------- Verify each AFW pump starts automatically on an actual or simulated actuation signal.	24 months
SR 3.7.4.5	----------NOTE---------- Not required to be performed for the steam driven AFW pump until prior to entering MODE 1. ---------- Verify proper alignment of the required AFW flow paths by verifying flow from the condensate storage tank to each steam generator.	Prior to entering MODE 2, whenever unit has been in MODE 5 or 6 for > 30 days
SR 3.7.4.6	Verify the AFW automatic bus transfer switch associated with discharge valve V2-16A operates automatically on an actual or simulated actuation signal.	24 months

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.6.1	----------NOTE---------- Isolation of CCW flow to individual components does not render the CCW System inoperable. ---------- Verify each required CCW manual, power operated, and automatic valve in the flow path servicing safety related equipment, that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days
SR 3.7.6.2	Verify each required CCW pump starts automatically on an actual or simulated LOP DG Start undervoltage signal.	24 months

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. Two Turbine Building loop isolation valves inoperable.	C.1	Close and deactivate one inoperable Turbine Building loop isolation valve.	2 hours
D. Required Actions and associated Completion Times of Conditions A, B, or C not met.	D.1	Be in MODE 3.	6 hours
	AND		
	D.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.7.1	----------NOTE---------- Isolation of SWS flow to individual components does not render the SWS inoperable. ---------- Verify each SWS manual, power operated, and automatic valve in the flow path servicing safety related equipment, that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days
SR 3.7.7.2	Verify each SWS automatic valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.7.7.3	Verify each SWS pump and SWS booster pump starts automatically on an actual or simulated actuation signal.	24 months
SR 3.7.7.4	Verify the SWS automatic bus transfer switch associated with Turbine Building loop isolation valve V6-16C operates automatically on an actual or simulated actuation signal.	24 months

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
H. Required Action and associated Completion Time of Condition G not met in MODE 1, 2, 3, or 4.	H.1 Be in MODE 3. AND H.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.9.1	Operate each CREFS train for ≥ 15 minutes.	31 days
SR 3.7.9.2	Perform required CREFS filter testing in accordance with the Ventilation Filter Testing Program (VFTP).	In accordance with VFTP
SR 3.7.9.3	Verify each CREFS train actuates on an actual or simulated actuation signal.	24 months
SR 3.7.9.4	Perform required CRE maintenance and testing in accordance with the CRE Habitability Program.	In accordance with the CRE Habitability Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.10.1	Verify each CREATC WCCU train has the capability to remove the assumed heat load.	24 months

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.7.11.3	----------NOTE---------- Not required to be met when the only movement of irradiated fuel is movement of the spent fuel shipping cask containing irradiated fuel. ---------- Verify the FBACS can maintain a negative pressure with respect to atmospheric pressure.	24 months

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.6	Verify the fuel oil transfer system operates to automatically transfer fuel oil from storage tank to the day tank.	31 days
SR 3.8.1.7	----------NOTES---------- All DG starts may be preceded by an engine prelube period. ---------- Verify each DG starts from standby condition and achieves in ≤ 10 seconds, voltage ≥ 467 V and frequency ≥ 58.8 Hz, and after steady state conditions are reached, maintains voltage ≥ 467 V and ≤ 493 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	184 days
SR 3.8.1.8	----------NOTES---------- 1. This Surveillance shall not be performed in MODE 1 or 2. 2. If performed with the DG synchronized with offsite power, it shall be performed at a power factor ≤ 0.9. ---------- Verify each DG rejects a load greater than or equal to its associated single largest post-accident load and does not trip on overspeed.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.9	----------NOTES---------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1, 2, 3, or 4. 3. During periods when a diesel generator is being operated for testing purposes, its protective trips need not be bypassed after the diesel generator has properly assumed the load on its bus. ----------	
	Verify on an actual or simulated loss of offsite power signal: a. De-energization of emergency buses; b. Load shedding from emergency buses; c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in ≤ 10 seconds, 2. energizes auto-connected shutdown loads through automatic load sequencer, 3. maintains steady state voltage ≥ 467 V and ≤ 493 V, 4. maintains steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz, and 5. supplies permanently connected and auto-connected shutdown loads for ≥ 5 minutes.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.10	----------NOTES---------- 1 All DG starts may be preceded by prelube period. 2. This Surveillance shall not be performed in MODE 1 or 2. 3. During periods when a diesel generator is being operated for testing purposes, its protective trips need not be bypassed after the diesel generator has properly assumed the load on its bus. ---------- Verify on an actual or simulated Engineered Safety Feature (ESF) actuation signal each DG auto-starts from standby condition and: a. In ≤ 10 seconds after auto-start achieves voltage ≥ 467 V, and after steady state conditions are reached, maintains voltage ≥ 467 V and ≤ 493 V; b. In ≤ 10 seconds after auto-start achieves frequency ≥ 58.8 Hz, and after steady state conditions are reached, maintains frequency ≥ 58.8 Hz and ≤ 61.2 Hz; c. Operates for ≥ 5 minutes; d. Permanently connected loads remain energized from the offsite power system; and e. Emergency loads are energized through the automatic load sequencer from the offsite power system.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.11	Verify each DG's automatic trips are bypassed except engine overspeed.	24 months
SR 3.8.1.12	----------NOTES---------- 1. Momentary transients outside the load and power factor ranges do not invalidate this test. 2. This Surveillance shall not be performed in MODE 1 or 2. 3. During periods when a diesel generator is being operated for testing purposes, its protective trips need not be bypassed after the diesel generator has properly assumed the load on its bus. ---------- Verify each DG operating at a power factor ≤ 0.9 operates for ≥ 24 hours: a. For ≥ 1.75 hours loaded ≥ 2650 kW and ≤ 2750 kW; and b. For the remaining hours of the test loaded ≥ 2400 kW and ≤ 2500 kW.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.13	----------NOTES---------- 1. This Surveillance shall be performed within 5 minutes of shutting down the DG after the DG has operated ≥ 2 hours loaded ≥ 2400 kW and ≤ 2500 kW. Momentary transients outside of load range do not invalidate this test. 2. All DG starts may be preceded by an engine prelube period. ---------- Verify each DG starts and achieves, in ≤ 10 seconds, voltage ≥ 467 V, and frequency ≥ 58.8 Hz, and after steady state conditions are reached, maintains voltage ≥ 467 V and ≤ 493 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	24 months
SR 3.8.1.14	----------NOTE---------- This Surveillance shall not be performed in MODE 1, 2, 3, or 4. ---------- Verify actuation of each sequenced load block is within ± 0.5 seconds of design setpoint for each emergency load sequencer.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.15	----------NOTES---------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1, 2, 3, or 4. 3. During periods when a diesel generator is being operated for testing purposes, its protective trips need not be bypassed after the diesel generator has properly assumed the load on its bus. ----------	
	Verify on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated ESF actuation signal: a. De-energization of emergency buses; b. Load shedding from emergency buses; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in ≤ 10 seconds, 2. energizes auto-connected emergency loads through load sequencer, 3. achieves steady state voltage ≥ 467 V and ≤ 493 V, 4. achieves steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz, and	24 months (continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.15 (continued)	5. supplies permanently connected and auto connected emergency loads for ≥ 5 minutes.	
SR 3.8.1.16	----------NOTE---------- 1. This Surveillance shall not be performed in MODE 1 or 2. 2. SR 3.8.1.16 is not required to be met if 4.160 kV bus 2 and 480 V Emergency Bus 1 power supply is from the start up transformer. ---------- Verify automatic transfer capability of the 4.160 kV bus 2 and the 480 V Emergency bus 1 loads from the Unit auxiliary transformer to the start up transformer.	24 months
SR 3.8.1.17	----------NOTE---------- All DG starts may be preceded by an engine prelube period. ---------- Verify when started simultaneously from standby condition, each DG achieves, in ≤ 10 seconds, voltage ≥ 467 V and frequency ≥ 58.8 Hz, and after steady state conditions are reached, maintains voltage ≥ 467 V and ≤ 493 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	10 years

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.4.2	Verify battery cells, cell plates, and racks show no visual indication of physical damage or abnormal deterioration that could degrade battery performance.	18 months
SR 3.8.4.3	Remove visible terminal corrosion, verify battery cell to cell and terminal connections are clean and tight, and are coated with anti-corrosion material.	24 months
SR 3.8.4.4	Verify each battery charger supplies ≥ 300 amps at ≥ 125 V for ≥ 4 hours.	24 months
SR 3.8.4.5	----------NOTES---------- 1. The modified performance discharge test in SR 3.8.4.6 may be performed in lieu of the service test in SR 3.8.4.5. 2. This Surveillance shall not be performed in MODE 1, 2, 3, or 4. ---------- Verify battery capacity is adequate to supply, and maintain in OPERABLE status, the required emergency loads for the design duty cycle when subjected to a battery service test.	24 months

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
G. Two trains with inoperable distribution subsystems that result in a loss of safety function.	G.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.9.1	----------NOTE---------- Actual voltage measurement is not required for the AC vital buses supplied from the constant voltage transformers. ---------- Verify correct breaker alignments and voltage to AC, DC, and AC instrument bus electrical power distribution subsystems.	7 days
SR 3.8.9.2	Verify capability of the two molded case circuit breakers for AFW Header Discharge Valve to S/G "A", V2-16A to trip on overcurrent.	24 months
SR 3.8.9.3	Verify capability of the two molded case circuit breakers for Service Water System Turbine Building Supply Valve (emergency supply), V6-16C to trip on overcurrent.	24 months

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.2.1	Perform CHANNEL CHECK.	12 hours
SR 3.9.2.2	----------NOTE---------- Neutron detectors are excluded from CHANNEL CALIBRATION. ---------- Perform CHANNEL CALIBRATION.	24 months

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.3.1	Verify each required containment penetration is in the required status.	7 days
SR 3.9.3.2	Verify each required containment ventilation valve actuates to the isolation position on an actual or simulated actuation signal.	24 months

5.5 Programs and Manuals

5.5.10 Secondary Water Chemistry Program (continued)

b. Procedures used to measure the critical parameters;

c. Requirements for the documentation and review of sample results;

d. Procedures which identify the administrative events and corrective actions required to return the secondary chemistry to its normal control band following an out of control band condition; and

e. Identification of the authority responsible for the interpretation of the sample results.

5.5.11 Ventilation Filter Testing Program (VFTP)

This program provides controls for implementation of the following required testing of Engineered Safety Feature (ESF) ventilation filter systems at the frequencies specified in Positions C.5 and C.6 of Regulatory Guide 1.52, Revision 2, March 1978, except that the testing specified at a frequency of 18 months is required at a frequency of 24 months, and conducted in general conformance with ANSI N510-1975 or N510-1980.

a. Demonstrate for each of the ESF systems that an inplace test of the high efficiency particulate air (HEPA) filters shows the specified penetration and system bypass leakage when tested in accordance with the referenced standard at the system flowrate specified below.

ESF Ventilation System	Penetration /Bypass	Flowrate	Reference Std
Control Room Emergency	<0.05%	3300 - 4150 ACFM	Regulatory Guide 1.52, Revision 2, March 1978, C.5.a, C.5.c, C.5.d (using ANSI N510-1980)
Spent Fuel Building	≤1%	11070- 13530 CFM	ANSI N510-1975
Containment Purge	≤1%	31500- 38500 CFM	ANSI N510-1975

(continued)

5.5 Programs and Manuals

5.5.17 Control Room Envelope Habitability Program (continued)

a. The definition of the CRE and the CRE boundary.
b. Requirements for maintaining the CRE boundary in its design condition, including configuration control and preventive maintenance.
c. Requirements for: (i) determining the unfiltered air inleakage past the CRE boundary into the CRE in accordance with the testing methods and at the frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, "Demonstrating Control Room Envelope Integrity at Nuclear Power Reactors," Revision 0, May 2003, and (ii) assessing CRE habitability at the frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, Revision 0.
The following exception is taken to Sections C.1 and C.2 of Regulatory Guide 1.197, Revision 0:
1. Unfiltered air inleakage testing shall include the ability to deviate from the test methodology of ASTM-E741. These exceptions shall be documented in the test report.
d. Measurement, at designated locations, of the CRE pressure relative to external areas adjacent to the CRE boundary during the pressurization mode of operation by one train of the CREFS, operating at the flow rate required by the VFTP, at a frequency of 24 months on a STAGGERED TEST BASIS. The results shall be trended and used as part of the assessment of the CRE boundary.
e. The quantitative limits on unfiltered air inleakage into the CRE. These limits shall be stated in a manner to allow direct comparison to the unfiltered air inleakage measured by the testing described in paragraph c. The unfiltered air inleakage limit for radiological challenges is the inleakage flow rate assumed in the licensing basis analyses of DBA consequences. For hazardous chemicals, inleakage rates shall be less than assumed in the licensing bases.
f. The provisions of SR 3.0.2 are applicable to the frequencies for assessing CRE habitability, determining CRE unfiltered inleakage, and measuring CRE pressure and assessing the CRE boundary as required by paragraphs c and d, respectively.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 258 TO

RENEWED FACILITY OPERATING LICENSE NO. DPR-23

DUKE ENERGY PROGRESS, LLC

H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2

DOCKET NO. 50-261

1.0 INTRODUCTION

By application dated April 3, 2017, as supplemented by letters dated April 3, May 2, and September 28, 2017, and January 8, 2018 (References 1-5), Duke Energy Progress, LLC (Duke Energy or the licensee), requested changes to the Technical Specifications (TSs) for H. B. Robinson Steam Electric Plant Unit No. 2 (HBRSEP). The proposed changes will revise the TSs for the HBRSEP to support operation with 24-month fuel cycles. Specifically, the change would revise certain TS Surveillance Requirements (SRs) and administrative controls program frequencies from 18 months to 24 months, in accordance with the guidance of Generic Letter (GL) 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle" (Reference 6).

The supplements dated September 28, 2017, and January 8, 2018, provided additional information that clarified the application, did not expand the scope of the application as originally noticed, and did not change the Nuclear Regulatory Commission (NRC or the Commission) staff's original proposed no significant hazards consideration determination as published in the *Federal Register* on July 5, 2017 (82 FR 31092).

2.0 REGULATORY EVALUATION

2.1 Background

Improved reactor fuels allow licensees to consider an increase in the duration of the fuel cycle for their facilities. The NRC staff has reviewed requests for individual plants to modify TS surveillance intervals to be compatible with a 24-month fuel cycle. The NRC staff issued GL 91-04 to provide generic guidance to licensees for preparing such license amendment requests (LARs).

The LAR divided the proposed TS changes into the following two categories consistent with GL 91-04: (1) changes to surveillance frequencies not involving channel calibrations, identified as "Non-Calibration Changes," and (2) changes to surveillance frequencies involving channel calibrations, identified as "Channel Calibration Changes." Guidance for non-calibration changes

is provided in GL 91-04, Enclosure 1, "Guidance on Preparation of a License Amendment Request for Changes in Surveillance Intervals to Accommodate a 24-Month Fuel Cycle." Guidance for calibration changes is provided in GL 91-04, Enclosure 2, "Guidance for Addressing the Effect of Increased Surveillance Intervals on Instrument Drift and Safety Analysis Assumptions."

GL 91-04, Enclosure 1 also acknowledges that the bounding time interval for the 24-month surveillances is 30 months due to the provision of TS SR 3.0.2 that allows a surveillance to be extended by 25% of the specified interval. Accordingly, the licensees are to evaluate the changed surveillances for 30 months consistent with GL 91-04, Enclosure 1.

2.2 Proposed Changes

The LAR Enclosure, Section 3, "Detailed Description of Proposed Changes," lists the SR and administrative program frequencies the licensee proposed to change to 24 months. The LAR Attachment 6, "Review of Historical Surveillance Records for Instrumentation," provides the licensee evaluation of surveillance data associated with calibration data. The LAR Attachment 8, "Non-Calibration Surveillance Failure Analysis," provides the licensee evaluation of surveillance data associated with non-calibration data. During the NRC staff acceptance review, the NRC staff identified that there were five SRs included in the LAR Enclosure, Section 3 that were not evaluated in the LAR Attachments 6 and 8. By letter dated May 2, 2017 (Reference 3), the licensee clarified that the five SRs will remain at an 18-month frequency and thus, should be omitted from the list of requested SR changes in LAR Enclosure, Section 3. With this correction, the SR and administrative program frequencies the licensee proposed to change to 24 months are listed below.

TS 3.1.7 Rod Position Indication

SR 3.1.7.1	Perform CHANNEL CALIBRATION of the ARPI [Analog Rod Position Indication] System (This was previously SR 3.1.7.4; however it was revised by HBRSEP Amendment 241, issued May 27, 2015 (Reference 7)).

TS 3.3.1 Reactor Protection System (RPS) Instrumentation

SR 3.3.1.10	Perform CHANNEL CALIBRATION Table 3.3.1-1 Functions 7.a, 7.b, 8, 9.a, 9.b, 11, 12, 13, 15.a, 17.e
SR 3.3.1.11	Perform CHANNEL CALIBRATION Table 3.3.1-1 Functions 2.a, 2.b, 3, 4, 17.a, 17.c, 17.d
SR 3.3.1.12	Perform CHANNEL CALIBRATION Table 3.3.1-1 Functions 5, 6
SR 3.3.1.13	Perform COT [Channel Operational Test] Table 3.3.1-1 Functions 17.a, 17.b, 17.c, 17.d, 17.e
SR 3.3.1.14	Perform TADOT [Trip Actuating Device Operational Test] Table 3.3.1-1 Functions 1, 10.a, 10.b, 12, 16, 17.b

TS 3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

SR 3.3.2.3	Perform MASTER RELAY TEST Table 3.3.2-1 Functions 1.b, 2.b, 3.a.2, 3.b.2, 4.b, 5.a
SR 3.3.2.5	Perform SLAVE RELAY TEST Table 3.3.2-1 Functions 1.b, 2.b, 3.a.2, 3.b.2, 4.b, 5.a
SR 3.3.2.6	Perform TADOT Table 3.3.2-1 Functions 1.a, 2.a, 3.a.1, 3.b.1, 4.a

SR 3.3.2.7 Perform CHANNEL CALIBRATION
Table 3.3.2-1 Functions 1.c, 1.d, 1.e, 1.f, 1.g, 2.c, 3.b.3, 4.c, 4.d, 4.e, 6.a, 6.b

TS 3.3.3 Post Accident Monitoring (PAM) Instrumentation

SR 3.3.3.2 Perform CHANNEL CALIBRATION
Table 3.3.3-1 Functions 1-8, 10-21

SR 3.3.3.3 Perform TADOT
Table 3.3.3-1 Functions 9, 22-24

TS 3.3.4 Remote Shutdown System

SR 3.3.4.3 Perform CHANNEL CALIBRATION for each required instrumentation channel
Table B 3.3.4-1 Functions 1.a, 2.a, 3.a, 3.b, 3.d, 3.e, 3.f, 4.a, 4.c

TS 3.3.5 Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

SR 3.3.5.1 Perform TADOT

SR 3.3.5.2 Perform CHANNEL Calibration with Trip Setpoints as follows:

a. Loss of voltage Trip Setpoint of 328 V [volts] +/- 10% with a time delay of ≤ 1 second (at zero voltage)

b. Degraded voltage Trip Setpoint of 430 V +/- 4V with a time delay of 10 +/- 0.5 seconds

TS 3.3.6 Containment Ventilation Isolation Instrumentation

SR 3.3.6.3 Perform MASTER RELAY TEST
Table 3.3.6-1 Function 2

SR 3.3.6.5 Perform SLAVE RELAY TEST
Table 3.3.6-1 Function 2

SR 3.3.6.6 Perform TADOT
Table 3.3.6-1 Function 1

SR 3.3.6.7 Perform CHANNEL CALIBRATION
Table 3.3.6-1 Functions 3.a and 3.b

TS 3.3.8 Auxiliary Feedwater (AFW) System Instrumentation

SR 3.3.8.3 Perform TADOT
Table 3.3.8-1 Functions 3, 4, 5

SR 3.3.8.4 Perform CHANNEL CALIBRATION
Table 3.3.8-1 Functions 1, 3, 4

TS 3.4.1 RCS [Reactor Coolant System] Pressure, Temperature and Flow Departure from Nucleate Boiling (DNB) Limits

SR 3.4.1.4 Verify by precision heat balance that RCS total flow rate is ≥ 97.3×10^6 lbm/hr [pound-mass per hour]

TS 3.4.9 Pressurizer

SR 3.4.9.2 Verify capacity of required pressurizer heaters is ≥ 125kW [kilowatts]

SR 3.4.9.3 Verify required pressurizer heaters are capable of being powered from an emergency supply

TS 3.4.11 Pressurizer Power Operated Relief Valves (PORVs)

SR 3.4.11.2 Perform a complete cycle of each PORV

SR 3.4.11.3 Perform a complete cycle of each solenoid air control valve and check valve on the nitrogen accumulators in PORV control system

SR 3.4.11.4 Verify accumulators are capable of operating PORVs through a complete cycle

TS 3.4.12 Low Temperature Overpressure Protection (LTOP) System

SR 3.4.12.7 Perform CHANNEL CALIBRATION for each required PORV actuation channel

TS 3.4.14 RCS Pressure Isolation Valves (PIVs)

SR 3.4.14.1 Verify leakage from each RCS PIV is less than or equal to an equivalent of 5 gpm [gallon per minute] at an RCS pressure ≥ 2235 psig [pounds per square inch gauge], and verify the margin between the results of the previous leak rate test and the 5 gpm limit has not been reduced by ≥ 50% for valves with leakage rate > 1.0 gpm

SR 3.4.14.2 Verify RHR [Residual Heat Removal] System interlock prevents the valves from being opened with a simulated or actual RCS pressure signal > 474 psig

TS 3.4.15 RCS Leakage Detection Instrumentation

SR 3.4.15.3 Perform CHANNEL CALIBRATION of the required containment sump monitor

SR 3.4.15.4 Perform CHANNEL CALIBRATION of the required containment atmosphere radioactivity monitor

SR 3.4.15.5 Perform CHANNEL CALIBRATION of the required containment fan cooler condensate flow rate monitor

TS 3.4.17 Chemical and Volume Control System (CVCS)

SR 3.4.17.2 Verify seal injection flow of ≥ 6 gpm to each RCP [Reactor Coolant Pump] from each Makeup Water Pathway from the RWST [Refueling Water Storage Tank]

TS 3.5.2 ECCS [Emergency Core Cooling Systems] – Operating

SR 3.5.2.4 Verify each ECCS automatic valve in the flow path that is locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal

SR 3.5.2.5 Verify each ECCS pump starts automatically on an actual or simulated actuation signal

SR 3.5.2.6 Verify, by visual inspection, the ECCS train containment sump suction inlet is not restricted by debris and the suction inlet trash strainers show no evidence of structural distress or abnormal corrosion

TS 3.6.3 Containment Isolation Valves

SR 3.6.3.2 Verify each containment isolation manual valve and blind flange that is located outside containment and not locked, sealed or otherwise secured and required to be closed during accident conditions is closed, except for containment isolation valves that are open under administrative controls.

SR 3.6.3.5 Verify each automatic containment isolation valve that is not locked, sealed or otherwise secured in position, actuates to the isolation position on an actual or simulated actuation signal

SR 3.6.3.6 Verify each 42 inch inboard containment purge valve is blocked to restrict the valve from opening > 70 degrees

TS 3.6.6 Containment Spray and Cooling Systems

SR 3.6.6.5 Verify each automatic containment spray valve in the flow path that is not locked, sealed or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal

SR 3.6.6.6 Verify each containment spray pump starts automatically on an actual or simulated actuation signal

SR 3.6.6.7 Verify each containment cooling train starts automatically on an actual or simulated actuation signal

TS 3.6.7 Spray Additive System

SR 3.6.7.4 Verify each spray additive automatic valve in the flow path that is not locked, sealed or otherwise secured in position, actuates to the correct position on an actual or simulated signal

TS 3.6.8 Isolation Valve Seal Water (IVSW) System

SR 3.6.8.4 Verify each automatic valve in the IVSW System actuates to the correct position on an actual or simulated actuation signal

SR 3.6.8.5 Verify the IVSW dedicated nitrogen bottles will pressurize the IVSW tank to ≥ 46.2 psig

SR 3.6.8.6 Verify total IVSW seal header flow rate is ≤ 124 cc/minute

TS 3.7.4 Auxiliary Feedwater (AFW) System

SR 3.7.4.3 Verify each AFW automatic valve that is not locked, sealed or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal

SR 3.7.4.4 Verify each AFW pump starts automatically on an actual or simulated actuation signal

SR 3.7.4.6 Verify the AFW automatic bus transfer switch associated with discharge valve V2-16A operates automatically on an actual or simulated actuation signal

TS 3.7.6 Component Cooling Water (CCW) System

SR 3.7.6.2 Verify each required CCW pump starts automatically on an actual or simulated LOP DG Start undervoltage signal

TS 3.7.7 Service Water System (SWS)

SR 3.7.7.2 Verify each SWS automatic valve in the flow path that is not locked, sealed or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal

SR 3.7.7.3 Verify each SWS pump and SWS booster pump starts automatically on an actual or simulated actuation signal

SR 3.7.7.4 Verify the SWS automatic bus transfer switch associated with the Turbine Building loop isolation valve V6-16C operates automatically on an actual or simulated actuation signal

TS 3.7.9 Control Room Emergency Filtration System (CREFS)

SR 3.7.9.3 Verify each CREFS train actuates on an actual or simulated actuation signal

TS 3.7.10 Control Room Emergency Air Temperature Control (CREATC)

SR 3.7.10.1 Verify each CREATC WCCU [Water Cooled Condensing Unit] train has the capability to remove the assumed heat load

TS 3.7.11 Fuel Building Air Cleanup System (FBACS)

SR 3.7.11.3 Verify the FBACS can maintain a negative pressure with respect to atmospheric pressure

TS 3.8.1 AC [alternating current] Sources – Operating

SR 3.8.1.8 Verify each DG rejects a load greater than or equal to its associated single largest post-accident load and does not trip on overspeed

SR 3.8.1.9 Verify on an actual or simulated loss of offsite power signal: Deenergizing of the emergency buses; load shedding from the emergency buses; and DG auto-starts from standby condition

SR 3.8.1.10 Verify on an actual or simulated ESF [engineered safety feature] actuation signal each DG auto-starts from standby condition

SR 3.8.1.12 Verify each DG operating at a power factor ≤ 0.9 operates for ≥ 24 hours

SR 3.8.1.13 Verify each DG starts and achieves, in ≤ 10 seconds, voltage ≥ 467 V, and frequency ≥ 58.8 Hz [hertz], and after steady state conditions are reached, maintains voltage ≥ 467 V and ≤ 493 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz

SR 3.8.1.14 Verify actuation of each sequenced load block is within +/- 0.5 seconds of design setpoint for each emergency load sequencer

SR 3.8.1.15 Verify on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated ESF actuation signal: De-energizing of the emergency buses; load shedding from the emergency buses; and DG auto-starts from standby condition

SR 3.8.1.16 Verify automatic transfer capability of the 4.16kV [kilovolt] bus 2 and the 480V Emergency bus 1 loads from the Unit auxiliary transformer to the start up transformer

TS 3.8.4 DC [direct current] Sources – Operating

SR 3.8.4.3 Remove visible terminal corrosion, verify battery cell to cell and terminal connections are clean and tight, and are coated with anti-corrosion material

SR 3.8.4.4 Verify each battery charger supplies ≥ 300 amps at ≥ 125 V for ≥ 4 hours

SR 3.8.4.5 Verify battery capacity is adequate to supply, and maintain in OPERABLE status, the required emergency loads for the design duty cycle when subjected to a battery service test

TS 3.8.9 Distribution Systems – Operating

SR 3.8.9.2 Verify capability of the two molded case circuit breakers for AFW Header Discharge Valve to S/G [Steam Generator] "A", V2-16A to trip on overcurrent

SR 3.8.9.3 Verify capability of the two molded case circuit breakers for Service Water System Turbine Building Supply Valve (emergency supply), V6-16C to trip on overcurrent

TS 3.9.2 Nuclear Instrumentation

SR 3.9.2.2 Perform CHANNEL CALIBRATION

TS 3.9.3 Containment Penetrations

SR 3.9.3.2 Verify each required containment ventilation valve actuates to the isolation position on an actual or simulated signal

TS 5.5.11 Ventilation Filter Testing Program

Ventilation Filter Testing Program (VFTP) - This program provides controls for implementation of the following required testing of Engineered Safety Feature (ESF) ventilation filter systems at the frequencies specified in Positions C.5 and C.6 of Regulatory Guide 1.52, Revision 2, March 1978, and conducted in general conformance with ANSI [American National Standards Institute] N510-1975 or N510-1980

TS 5.5.17 Control Room Envelope Habitability Program

5.5.17(d) Measurement, at designated locations, of the CRE [Control Room Envelope] pressure relative to external areas adjacent to the CRE boundary during the pressurization mode of operation by one train of the CREFS, operating at the flow rate required by the VFTP [Ventilation Filter Testing Program], at a frequency of 18 months on a STAGGERED TEST BASIS. The results shall be trended and used as part of the assessment of the CRE boundary.

The NRC staff reviewed the proposed TS changes against the regulatory requirements listed in Section 2.3.1 and guidance listed in Section 2.3.2 of this safety evaluation (SE) to ensure that there is reasonable assurance that the systems and components affected by the proposed TS changes will continue to perform their safety functions.

The licensee evaluated the steam generator (SG) inservice inspections in regard to a 24-month fuel cycle and determined the existing inspection interval is compatible with an extended fuel cycle; therefore, the licensee did not request a change to the inspection interval. The SG Program in TS 5.5.9, "Steam Generator (SG) Program," supports a 24-month fuel cycle; therefore, the NRC staff agrees that a change to SG Program is not required.

2.3 Regulatory Requirements and Guidance

2.3.1 Regulatory Requirements

The NRC staff considered the following regulatory requirements related to this application:

Title 10 of the *Code of Federal Regulations* (10 CFR) Section 50.36, "Technical specifications," details the content and information that must be included in a station's TSs. Specifically, 10 CFR 50.36 states, in part, that

> Each applicant for a license authorizing operation of a production or utilization facility shall include in his application proposed technical specifications in accordance with the requirements of this section.

In addition, 10 CFR 50.36(c)(3) states,

> Surveillance requirements are requirements relating to test, calibration, or inspection to assure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions for operation will be met.

The regulations in 10 CFR 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants," require that preventive maintenance activities must not reduce the overall availability of the systems, structures, and components.

Furthermore, the NRC staff used the guidance in Section 2.3.2 of this SE to review the proposed TS changes against these requirements to ensure that there is reasonable assurance that the systems affected by the proposed TS changes will perform their required safety functions.

2.3.2 Regulatory Guidance

The NRC staff considered the regulatory guidance provided in GL 91-04. GL 91-04, Enclosure 1, indicates that SRs with an 18-month frequency requirement that are not instrument calibration related should be evaluated for the effect on safety associated with an extension to a 24-month required interval. This evaluation should address the following.

- The licensee should analyze the effect on plant safety from the change in surveillance intervals to accommodate a 24-month fuel cycle. This evaluation should support a conclusion that the effect on safety is small,

- The licensee should confirm that historical maintenance and surveillance data do not invalidate this conclusion that the effect on safety is small, and

- The licensee should confirm that the performance of surveillance at the bounding surveillance interval limit would not invalidate any assumption in the plant licensing basis.

For those SRs where the evaluation accomplishes these goals, the licensees need not quantify the effect of the change in surveillance intervals on the availability of individual systems or components. No change in the existence, testability, or availability of plant systems and components is being requested, only the extension in the frequency of tests or inspections.

GL 91-04 Enclosure 2, stipulates that the licensee should evaluate the following for calibration-related frequency changes:

- Confirm that instrument drift as determined by as-found and as-left calibration data from surveillance and maintenance records has not, except on rare occasions, exceeded acceptable limits for a calibration interval.

- Confirm that the values of drift for each instrument type (make, model, and range) and application have been determined with a high probability and a high degree of confidence. Summarize the methodology and assumptions used to determine the rate of instrument drift with time based upon historical plant calibration data.

- Confirm that the magnitude of instrument drift has been determined with a high probability and a high degree of confidence for a bounding calibration interval of 30 months for each instrument type (make, model number, and range) and application that performs a safety function. Provide a list of the channels by TS section that identifies these instrument applications.

- Confirm that a comparison of the projected instrument drift errors has been made with the values of drift used in the setpoint analysis. If this results in revised setpoints to accommodate larger drift errors, provide proposed TS changes to update trip setpoints. If the drift errors result in a revised safety analysis to support existing setpoints, summarize the updated analysis conclusions to confirm that safety limits and safety analysis assumptions are not exceeded.

- Confirm that the projected instrument errors caused by drift are acceptable for the control of plant parameters to affect a safe shutdown with the associated instrumentation.

- Confirm that all conditions and assumptions of the setpoint and safety analyses have been checked and are appropriately reflected in the acceptance criteria of plant surveillance procedures for channel checks, channel functional tests, and channel calibrations.

- Provide a summary description of the program for monitoring and assessing the effects of increased calibration surveillance intervals on instrument drift and on safety.

NRC Regulatory Guide (RG) 1.105, Revision 3, "Setpoints for Safety-Related Instrumentation," December 1999 (Reference 8), describes a method that the NRC staff considers acceptable for complying with the agency's regulations for ensuring that setpoints for safety-related instrumentation are initially within and remain within the TS limits. RG 1.105 endorses Part 1 of Instrument Society of America (ISA) Standard 67.04-1994, "Setpoints for Nuclear Safety-Related Instrumentation," subject to NRC staff clarifications. The staff used this guide to review the adequacy of the licensee's setpoint calculation methodologies and the related plant surveillance procedures.

Regulatory Issue Summary (RIS) 2006-17, "NRC Staff Position on the Requirements of 10 CFR 50.36, 'Technical specifications', regarding Limiting Safety System Settings during Periodic Testing and Calibration of Instrument Channels," dated August 24, 2006 (Reference 9), addresses requirements on limiting safety system settings that are assessed during the periodic testing and calibration of instrumentation. RIS 2006-17 discusses issues that could occur during the testing of limiting safety system settings and that, therefore, may have an adverse effect on equipment operability.

The NRC has previously approved similar license amendments for Monticello Nuclear Generating Plant (September 30, 2005), Clinton Power Station, Unit 1 (October 21, 2005), Browns Ferry Nuclear Plant, Unit 1 (September 28, 2006), River Bend Station, Unit 1 (August 31, 2010), Oconee Nuclear Station, Units 1, 2, and 3 (April 20, 2012), Cooper Nuclear Station (September 28, 2012), and Grand Gulf Nuclear Station, Unit 1 (December 26, 2013) (References 10-16). These past amendments were used to inform the scope of this review and the acceptability of proposed approaches.

3.0 TECHNICAL EVALUATION

Consistent with the licensee's LAR and the guidance in GL 91-04, the NRC staff evaluation is divided into two categories, (1) noncalibration-related changes and (2) calibration-related changes. Noncalibration-related changes are addressed in the LAR Enclosure, Section 4.1, "Non-Calibration Changes," and the LAR Attachment 8. Calibration-related changes are addressed in LAR Enclosure, Section 4.2, "Channel Calibration Changes," and the LAR Attachment 6.

3.1 Noncalibration-Related Changes

The purpose of surveillance testing is to verify that the tested TS function/feature will perform as assumed in the associated safety analysis. By periodically testing the TS function/feature, the availability of the associated function/feature is confirmed. Section 4.1 of the LAR Enclosure

and the response to General Request for Additional Information (RAI)-1 (Reference 4) (further discussed below) describe the study the licensee performed to determine if the noncalibration related historical surveillance performances ensure that the availability and reliability of systems, components, and functions will not be significantly reduced by repetitive or time based failures and that the effect on safety is small. The licensee states that the study demonstrated that the surveillance test history does not indicate a history of repetitive failures that would go undetected if the current surveillance interval were extended to the proposed surveillance interval.

The licensee further stated that the study included an engineering analysis of the historical maintenance records for outage based surveillance and nonsurveillance preventive maintenance (PM) tasks to ascertain if any failure history of any components would preclude lengthening the surveillance frequency for these components to 24 months (maximum 30 months) versus 18 months. The study reviewed a minimum of five surveillance performances of each component's test history to provide 7 years of potential failure data. The licensee stated that in most cases seven surveillance performances were used to provide 10 years of potential failure data. The surveillance test history study is a qualitative review of the surveillance test performances to ensure there is no evidence of any repetitive failures associated with the SR that would invalidate the conclusion that the impact on system availability, if any, will be small as a result of the change to a 24-month surveillance interval. The five performances ensure that approximately three 30-month surveillance periods are reviewed to identify any repetitive problems. The licensee has concluded, based on engineering judgement and similar precedent applications accepted by the NRC, that three 30-month periods provide adequate surveillance test history. The licensee further stated that it has validated for all of the surveillances that there was no evidence of repetitive failures or failures caused by a time based failure mechanism that would invalidate the conclusion that the impact, if any, on system availability will be small as a result of changing to a 24-month performance interval.

The NRC staff reviewed the licensee's approach to the analysis of the historical surveillance and maintenance information and finds that the approach conforms to the guidelines of GL 91-04, Enclosure 1 regarding noncalibration changes. The NRC staff further evaluated the results of this analysis for each of the noncalibration-related proposed surveillance interval changes below.

The Licensee's Failure Categorization Process

The response to General RAI-1 (Reference 4) describes the licensee's categorization process. In particular, the RAI response included a flow chart designated, "Appendix A – Categorization Flow Chart," that classifies all 18-month surveillance failures into four categories. The flow chart is included as an appendix to this SE. For each of the four categories, the following identifies (1) the question for the category used in the flow chart, (2) the disposition of the category (i.e., category definition) based on either a "No" or "Yes" answer to question, and (3) the shorthand phrase used for the category in the LAR and this SE.

- Category A
  Question: Does the failure degrade or make inoperable the safety function?
  Disposition based on "No" Answer: Since the failure does not impact any safety function, the failure does not invalidate the conclusion that the increased surveillance interval will have a small, if any, impact on system availability.
  Shorthand Name in LAR and SE: The failure would not have impacted the safety function.

- Category B
  Question: Is the failure detectable by a test, maintenance activity, or plant monitoring which is performed on a more frequent basis than once per surveillance interval?
  Disposition based on a "Yes" Answer: Since the failure would be detected by a more frequent activity, there is no potential impact from an increase to the surveillance interval since the failure will not go undetected for a longer period of time.
  Shorthand Name in LAR and SE: The failure would been detected by other more frequent testing.

- Category C
  Question: Was the failure caused by a unique [specific][1] maintenance activity that was performed prior to the performance of the failed surveillance test?
  Disposition based on a "yes" Answer: Since the failure was caused by a specific activity, which if performed requires the performance of the corresponding test, the failure does not invalidate the conclusion that the impact, if any from the increased test interval on system availability is small.
  Shorthand Name in LAR and SE: The failure is event driven.

- Category D
  Question: Is the failure caused by a time based failure mechanism such as erosion, fatigue wear, etc. or is it not unique?
  Disposition based on a "No" Answer: If the failure mechanism can be proven not to be related to a time-based degradation [mechanism] and [to be] unique, then the failure does not invalidate the conclusion that the increased operating cycle will have a small, if any, impact on system availability. This conclusion should be supported by an additional review of the surveillance test history.[2]
  Shorthand Name in LAR and SE: Unique failure.

If the surveillance could not be placed into these four categories, the licensee would perform an additional evaluation to determine if the extended surveillance interval can be justified. Otherwise, the licensee would evaluate the possibility to perform the surveillance at power. The NRC staff notes that all surveillance interval changes proposed and evaluated by the licensee for this LAR have fallen into Categories A through D, or combinations thereof, with none requiring additional evaluations.

The licensee states that the disposition of Categories A, B, and C are generically justified in that they can be demonstrated to not change the conclusion that the impact on system availability, if any, will be small as a result of the change to a 24-month surveillance test interval based on justifications in the flow chart and reproduced above. The NRC staff agrees with this assessment. In addition, these types of failures have been excluded from previous similar licensing submittals. In the LAR, the licensee includes the number of surveillance history failures in Categories A, B, and C, and briefly describes the Category C (i.e., event driven) failures. As discussed further below, since the NRC staff agreed, the disposition of the

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[1] Category C uses the word "unique" in a different sense than Category D. As Category D is a significant part of the review, the different sense in Category C is clarified. In Category C, the word "unique" is understood to mean "specific."

[2] A "no" answer to the question in Category D means the failure is unique: (1) the failure was not caused by a time based failure mechanism such as erosion, fatigue wear, etc.; and (2) the failure was not "not unique" (i.e. the failure was unique).

surveillance history failures in these categories, the number of surveillance history failures in Categories A, B, and C will be identified in this SE for each surveillance, but not further discussed.

The licensee states that each Category D failure was evaluated individually and collectively to ensure that repetitive failures of similar components tested by different surveillance tests would be identified. The LAR includes summary of each Category D (i.e., unique) failure and its evaluation and disposition. The NRC staff reviewed each Category D failure and its disposition and briefly discusses each Category D failure in this SE. For those failures the licensee evaluated further, the licensee dispositioned the failures since there were no time based nor repetitive failures that would have a significant effect on system availability.

Safety Evaluation Documentation of Failures Identified by the Licensee

Based on the NRC staff's understanding of the licensee's categorization process, this SE will repeat the number of failures identified by the licensee in the first three categories (Category A: the failure would not have impacted the safety function, Category B: the failure would been detected by other more frequent testing, and Category C: the failure is event driven) but will not further discuss them. This approach is taken because these three categories of failures do not impact an extension to a 24-month surveillance interval and these types of failures typically have been excluded from previous similar licensing submittals. The SE will specifically discuss the failures identified by the licensee and designated as unique failures.

Resolution of General-RAI-1

The NRC staff noted that LAR Attachment 8 lists the same three unique failure histories for a significant number of SRs. The licensee also identified two common event driven failures and ten common failures that would not have impacted the safety function. The LAR states that the test procedure and preventive maintenance task implementing these SRs are very large and test a wide range of equipment. It was not clear to the NRC staff how these failures were representative enough to demonstrate the lack of impact of the change in SR frequency for the wide range of and diversity of the SRs. Therefore in General RAI-1, dated August 31, 2017 (Reference 17), the NRC staff requested the licensee (1) to clarify the shared characteristics of the SRs that allow them to be treated as a group and (2) to confirm that the same failure histories applies to all the SRs.

The licensee identified the test procedure that was the subject of General RAI-1 as OST-163, "Safety Injection Test and Emergency Diesel Generator Auto Start on Loss of Power and Safety Injection (Refueling)" and the engineering evaluation of the failures found in the test as EC 407942. The licensee also included an excerpt from Attachment C to EC 407942 that evaluated all failures found for OST-163 for the period between years 2005 and 2015. The licensee's review of the applicable HBRSEP surveillance history for the associated SRs determined that there were a total of 15 failures, with three of them being unique failures. Two of the three unique failures were related to battery chargers. Both failures were related to replacement of relays. The affected battery chargers were subsequently replaced. The third of three unique failures was related to the Westinghouse Model DB-50 breakers, which included a failed microswitch in a breaker, and one breaker was not closing as expected. The licensee determined that there was no time based mechanisms involved with the three failures. Therefore, the licensee concluded that as these failures are unique and any subsequent failure would not result in a significant impact on system/component availability, increasing the surveillance interval will only have a minimal, if any, impact on system availability.

The licensee explained that the apparent group was due to the broad scope of the test procedure and the licensee's failure categorization process. If a surveillance test procedure was failed, the licensee applied the failure to the failure history of all SRs that the test procedure credited, even when only one section of the test procedure was failed. Since the licensee was able to disposition the failures for the surveillance test procedure using the categorization process, the licensee determined that it was not necessary to further evaluate the failures based on the characteristics of specific SRs or to further refine the applicability of the failure histories. The NRC staff finds this approach acceptable and therefore, General RAI-1 is resolved.

Organization of SE Section 3.1

SRs with no unique failures share a similar evaluation and SE finding. Likewise SRs with the same unique failures also share a similar evaluation and SE finding. Therefore, to avoid unnecessary repetition, Section 3.1 is broken into three sub-sections:

3.1.1 Surveillance Requirements with No Unique Failures
3.1.2 Surveillance Requirements with the Same Three Unique Failures
3.1.3 Surveillance Requirements with Other Unique Failures or NRC Staff Requests for Additional Information

3.1.1 Surveillance Requirements with No Unique Failures

The SRs evaluated in this Section of the SE are those for which the licensee either identified no failures or a combination of failures that fall into Categories A, B, and C of the licensee's failure categorization process (see Section 3.1 of this SE). The SRs with unique failures (i.e., failures that fall into Category D of the licensee's failure categorization process) are not evaluated in this Section of the SE. The surveillance test intervals of these SRs are being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. While the SRs in this subsection may be otherwise unrelated, as the SRs have no unique failures to evaluate, the SRs share the same NRC staff evaluation.

TS 3.3.1 Reactor Protection System (RPS) Instrumentation

SR 3.3.1.14 Perform TADOT

Table 3.3.1-1, Function 1: Manual Reactor Trip

Table 3.3.1-1, Function 10.a: Reactor Coolant Pump (RCP) Breaker Position - Single Loop

Table 3.3.1-1, Function 10.b: Reactor Coolant Pump (RCP) Breaker Position - Two Loops

Table 3.3.1-1, Function 12: Underfrequency RCPs

Table 3.3.1-1, Function 17.b: Reactor Protection System Interlocks – Low Power Reactor Trips Block, P-7

This SR is the performance of a TADOT of the manual reactor trip, RCP breaker position, and the safety injection input from ESFAS and the P-7 interlock (blocks various reactors trips at low neutron flux and low turbine pressure). For Function 1, the licensee identified one failure that would not have impacted the safety function. For Functions 10a, 10b, and 12, the licensee identified no failures. For Function 17, the licensee identified three event driven failures in the procedure and preventive maintenance task required to satisfy the SR that were determined to have no impact on the proposed extension to 24-month surveillance interval.

TS 3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

SR 3.3.2.3 Perform MASTER RELAY TEST

SR 3.3.2.5 Perform SLAVE RELAY TEST

Table 3.3.2-1, Function 2.b: Containment Spray – Automatic Actuation Logic and Actuation Relays

Table 3.3.2-1, Function 3.b.2: Containment Isolation - Phase B Isolation - Automatic Actuation Logic and Actuation Relays

Table 3.3.2-1, Function 4.b: Steam Line Isolation - Automatic Actuation Logic and Actuation Relays

SR 3.3.2.3 is the performance of a master relay test, which is the energizing of the master relays. SR 3.3.2.5 is the performance of a master relay test, which is the energizing of the slave relays. For Functions 2.b, 3.b.2, and 4.b, the licensee identified one common event driven failure in the procedure and preventive maintenance task required to satisfy the SR that was determined to have no impact on the proposed extension to 24-month surveillance interval.

TS 3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

SR 3.3.2.6 Perform TADOT

Table 3.3.2-1, Function 2.a: Containment Spray – Manual Initiation

Table 3.3.2-1, Function 3.b.1: Containment Isolation – Phase B Isolation - Manual Initiation

Table 3.3.2-1, Function 4.a: Steam Line Isolation - Manual Initiation

SR 3.3.2.6 is the performance of a TADOT of manual actuation functions. For Functions 2.a and 3.b.1 the licensee identified one common event driven failure in the procedure and preventive maintenance task required to satisfy the SR that was determined to have no impact on the proposed extension to 24-month surveillance interval. For Function 4.a the licensee identified two failures that would not have impacted the safety function.

TS 3.3.3 Post Accident Monitoring (PAM) Instrumentation

SR 3.3.3.3 Perform TADOT

Table 3.3.3-1 Function 23: PORV Block Valve Position (Primary)

This SR is the performance of a TADOT of containment isolation valve position indication, PORV position (primary) indication, PORV block valve position (primary) indication, and safety valve position (primary) indication. For this SR the licensee identified one event driven failure in the procedure and preventive maintenance task required to satisfy the SR that was determined to have no impact on the proposed extension to 24-month surveillance interval.

TS 3.3.8 Auxiliary Feedwater (AFW) System Instrumentation

SR 3.3.8.3 Perform TADOT

Table 3.3.8-1, Function 4 – Undervoltage Reactor Coolant Pump

Table 3.3.8-1, Function 5 – Trip of all Main Feedwater Pumps

This SR is the performance of a TADOT. This test is a check of AFW automatic pump start on loss of offsite power, undervoltage RCP, and trip of all main feedwater pumps Functions. For Function 4 the licensee identified one failure that would not have impacted the safety function. For Function 5 the licensee identified no failures.

TS 3.4.11 Pressurizer Power Operated Relief Valves (PORVs)

SR 3.4.11.2 Perform a complete cycle of each PORV

This SR requires a complete cycle of each PORV. Operating a PORV through one complete cycle ensures that the PORV can be manually actuated. For this SR the licensee identified no failures.

TS 3.4.14 RCS Pressure Isolation Valves (PIVs)

SR 3.4.14.1 Verify leakage from each RCS PIV is less than or equal to an equivalent of 5 gpm at an RCS pressure ≥ 2235 psig, and verify the margin between the results of the previous leak rate test and the 5 gpm limit has not been reduced by ≥ 50% for valves with leakage rate > 1.0 gpm

This SR verifies that leakage from the high pressure portion of the affected system to the low pressure portion is below the specified limit and identifies each leaking valve. For this SR, the licensee identified two event driven failures in the procedure and preventive maintenance task required to satisfy the SR that were determined to have no impact on the proposed extension to 24-month surveillance interval.

TS 3.4.14 RCS Pressure Isolation Valves (PIVs)

SR 3.4.14.2 Verify RHR System interlock prevents the valves from being opened with a simulated or actual RCS pressure signal > 474 psig

This SR verifies the RHR system interlock that prevents the valves from being opened with a simulated or actual RCS pressure signal > 474 psig. Any calibration out-of-tolerance conditions identified will be compared to the as-found/as-left values to determine if acceptable limits were exceeded. The licensee evaluated this SR as a calibration related change and identified no failures.

TS 3.4.17 Chemical and Volume Control System (CVCS)

SR 3.4.17.2 Verify seal injection flow of ≥ 6 gpm to each RCP from each Makeup Water Pathway from the RWST

This SR verifies seal injection flow to the RCP seals via the Makeup Water Pathways, ensuring that adequate cooling to the RCP seals can be maintained from the RWST. For this SR the licensee identified no failures.

TS 3.5.2 ECCS – Operating

SR 3.5.2.6 Verify, by visual inspection, the ECCS train containment sump suction inlet is not restricted by debris and the suction inlet trash strainers show no evidence of structural distress or abnormal corrosion

This SR provides periodic inspections of the containment sump suction inlet to ensure that it is unrestricted and stays in proper operating condition. For this SR the licensee identified two failures that would not have impacted the safety function.

TS 3.6.3 Containment Isolation Valves

SR 3.6.3.2 Verify each containment isolation manual valve and blind flange that is located outside containment and not locked, sealed or otherwise secured and required to be closed during accident conditions is closed, except for containment isolation valves that are open under administrative controls.

This SR verifies that each containment isolation manual valve and blind flange located outside containment and not locked, sealed or otherwise secured and required to be closed during accident conditions is closed. The SR helps to ensure that post-accident leakage of radioactive fluids or gases outside of the containment boundary is within design limits. For this SR, the licensee identified three event driven failures in the procedure and preventive maintenance task required to satisfy the SR that were determined to have no impact on the proposed extension to 24-month surveillance interval.

TS 3.6.3 Containment Isolation Valves

SR 3.6.3.6 Verify each 42 inch inboard containment purge valve is blocked to restrict the valve from opening > 70 degrees

This SR verifies that each 42 inch inboard containment purge valve is blocked to restrict opening to ≤ 70° to ensure that the valves can close under design basis accident (DBA) conditions within the times assumed in the analyses in the Updated Final Safety Analysis Report (UFSAR). If a Loss-of-Coolant Accident occurs, the purge valves must close to maintain containment leakage within the values assumed in the accident analysis. At other times when purge valves are required to be capable of closing (e.g., during movement of irradiated fuel assemblies), pressurization concerns are not present, thus the purge valves can be fully open. For this SR the licensee identified no failures.

TS 3.6.6 Containment Spray and Cooling Systems

SR 3.6.6.5 Verify each automatic containment spray valve in the flow path that is not locked, sealed or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal

SR 3.6.6.6 Verify each containment spray pump starts automatically on an actual or simulated actuation signal

These SRs verify that each automatic containment spray valve actuates to its correct position and that each containment spray pump starts upon receipt of an actual or simulated actuation of a containment High - High pressure signal. For these SRs the licensee identified one common event driven failure in the procedure and preventive maintenance task required to satisfy the SR that was determined to have no impact on the proposed extension to 24-month surveillance interval.

TS 3.6.7 Spray Additive System

SR 3.6.7.4 Verify each spray additive automatic valve in the flow path that is not locked, sealed or otherwise secured in position, actuates to the correct position on an actual or simulated signal

This SR verifies that each automatic valve in the Spray Additive System flow path actuates to its correct position. For this SR the licensee identified one event driven failure in the procedure and preventive maintenance task that was determined to have no impact on the proposed extension to a 24-month surveillance interval.

TS 3.7.4 Auxiliary Feedwater (AFW) System

SR 3.7.4.6 Verify the AFW automatic bus transfer switch associated with discharge valve V2-16A operates automatically on an actual or simulated actuation signal

This SR verifies that the automatic bus transfer switch associated with the "swing" motor driven AFW flow path discharge valve V2-16A will function properly to automatically transfer the power source from the aligned emergency power source to the other emergency power source upon

loss of power to the aligned emergency power source. For this SR the licensee identified no failures.

TS 3.7.6 Component Cooling Water (CCW) System

SR 3.7.6.2 Verify each required CCW pump starts automatically on an actual or simulated LOP DG Start undervoltage signal

This SR verifies proper automatic operation of the required CCW pumps on an actual or simulated LOP DG start undervoltage signal. The CCW System is a normally operating system that cannot be fully actuated as part of routine testing during normal operation. For this SR the licensee identified no failures.

TS 3.7.7 Service Water System (SWS)

SR 3.7.7.2 Verify each SWS automatic valve in the flow path that is not locked, sealed or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal

SR 3.7.7.4 Verify the SWS automatic bus transfer switch associated with the Turbine Building loop isolation valve V6-16C operates automatically on an actual or simulated actuation signal

SR 3.7.7.2 verifies proper automatic operation of the SWS valves on an actual or simulated actuation signal. The SWS is a normally operating system that cannot be fully actuated as part of normal testing. SR 3.7.7.4 verifies that the automatic bus transfer switch associated with turbine building service water isolation valve V6-16C, will function properly to automatically transfer the power source from the aligned emergency power source to the other emergency power source upon loss of power to the aligned emergency power source. For these SRs the licensee identified four common event driven failures in the procedure and preventive maintenance task required to satisfy the SR that were determined to have no impact on the proposed extension to 24-month surveillance interval and one common failure that would not have impacted the safety function.

TS 3.7.10 Control Room Emergency Air Temperature Control (CREATC)

SR 3.7.10.1 Verify each CREATC WCCU train has the capability to remove the assumed heat load

This SR verifies that the heat removal capability of the system is sufficient to remove the heat load assumed in the control room. For this SR the licensee identified no failures.

TS 3.7.11 Fuel Building Air Cleanup System (FBACS)

SR 3.7.11.3 Verify the FBACS can maintain a negative pressure with respect to atmospheric pressure

This SR verifies the integrity of the fuel building enclosure. For this SR the licensee identified one failure that would not have impacted the safety function.

TS 3.8.9 Distribution Systems – Operating

SR 3.8.9.2 Verify capability of the two molded case circuit breakers for AFW Header Discharge Valve to S/G "A", V2-16A to trip on overcurrent

SR 3.8.9.3 Verify capability of the two molded case circuit breakers for Service Water System Turbine Building Supply Valve (emergency supply), V6-16C to trip on overcurrent

These SRs verify that the two breakers associated with each automatic bus transfer will trip on overcurrent as required to prevent the fault from affecting both trains of the AC Distribution System. For these SRs the licensee identified three failures that would not have impacted the safety function.

Conclusion for Surveillance Requirements with No Unique Failures

The licensee's review of the applicable HBRSEP surveillance histories demonstrated that no unique failures were experienced when performing the procedures and preventive maintenance tasks required to satisfy these SRs. As such, the impact, if any, on system availability is minimal from the proposed changes to 24-month testing frequencies. Therefore, based on the histories of system performance, the licensee concluded that the impact of these change on safety, if any, is small.

The NRC staff reviewed the proposed changes and the licensee's justification for the changes, and determined that all actions specified in the GL were completed. In particular, the NRC staff confirmed that the failure histories as described in the LAR fell into Categories A, B, or C of the licensee's failure categorization. As described above, the NRC staff considers for SRs in these categories, the effect on safety of a 24-month test frequency would be insignificant, historical data does not contradict this conclusion, and no assumptions in the plant licensing basis would be invalidated. The NRC staff finds the proposed interval extensions acceptable for the listed SRs based on 1) consistency with the guidance provided in the GL 91-04, 2) historical plant maintenance and surveillance data supporting the conclusion, and 3) that the assumptions in the plant licensing-basis would not be invalidated as a result of this revision.

3.1.2 Surveillance Requirements with the Same Three Unique Failures

As previously noted, the licensee identified the same three unique failure histories (i.e., failures that fall into Category D of the licensee's failure categorization process as discussed in Section 3.1 of this SE.) for the SRs evaluated in this section. The licensee also identified two common event driven failures in the procedure and preventive maintenance task that were determined to have no impact on the proposed extension to a 24-month surveillance interval and 10 common failures that would not have impacted the safety function. While otherwise unrelated, the SRs share the same NRC staff evaluation and conclusion.

The surveillance test intervals of these SRs are being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period.

TS 3.3.1 Reactor Protection System (RPS) Instrumentation

SR 3.3.1.14 Perform TADOT

Table 3.3.1-1, Function 16 – Safety Injection (SI) Input from Engineered Safety Feature Actuation System (ESFAS)

This SR is the performance of a TADOT of the manual reactor trip, RCP breaker position, and the safety injection input from ESFAS and the P-7 interlock (blocks various reactors trips at low neutron flux and low turbine pressure).

TS 3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

SR 3.3.2.3 Perform MASTER RELAY TEST

SR 3.3.2.5 Perform SLAVE RELAY TEST

Table 3.3.2-1, Function 1.b: Safety Injection – Automatic Actuation Logic and Actuation Relays

Table 3.3.2-1, Function 3.a.2: Containment Isolation - Phase A Isolation - Automatic Actuation Logic and Actuation Relays

Table 3.3.2-1, Function 5.a: Feedwater Isolation - Automatic Actuation Logic and Actuation Relays

SR 3.3.2.3 is the performance of a master relay test, which is the energizing of the master relays. SR 3.3.2.5 is the performance of a master relay test, which is the energizing of the slave relays.

TS 3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

SR 3.3.2.6 Perform TADOT

Table 3.3.2-1, Function 1.a: Safety Injection – Manual Initiation

Table 3.3.2-1, Function 3.a.1: Containment Isolation – Phase A Isolation - Manual Initiation

This SR is the performance of a TADOT of manual actuation functions.

TS 3.3.3 Post Accident Monitoring (PAM) Instrumentation

SR 3.3.3.3 Perform TADOT

Table 3.3.3-1, Function 9: Containment Isolation Valve Position

This SR is the performance of a TADOT of containment isolation valve position indication, PORV position (primary) indication, PORV block valve position (primary) indication, and safety valve position (primary) indication.

TS 3.3.6 Containment Ventilation Isolation Instrumentation

SR 3.3.6.3 Perform MASTER RELAY TEST

Table 3.3.6-1, Function 2 – Automatic Actuation Logic and Actuation Relays

SR 3.3.6.5 Perform SLAVE RELAY TEST

Table 3.3.6-1, Function 2 – Automatic Actuation Logic and Actuation Relays

SR 3.3.6.6 Perform TADOT

Table 3.3.6-1, Function 1 – Manual Initiation

SR 3.3.6.3 is the performance of a master relay test. SR 3.3.6.5 is the performance of a slave relay test. SR 3.3.6.6 is the performance of a TADOT. Each manual actuation function is tested up to, and including, the master relay coils. In some instances, the test includes actuation of the end device (i.e., pump starts, valve cycles, etc.). The test also includes trip devices that provide actuation signals directly to the relay logic, bypassing the analog process control equipment. The SR is modified by a Note that excludes verification of setpoints during the TADOT. The Functions tested have no setpoints associated with them. In addition to the common failures identified for all SRs in this Section of the SE, one additional event driven failure in the procedure and preventive maintenance task required to satisfy SR 3.3.6.6 was identified that was determined to have no impact on the proposed extension to 24-month surveillance interval.

TS 3.3.8 Auxiliary Feedwater (AFW) System Instrumentation

SR 3.3.8.3 Perform TADOT

Table 3.3.8-1, Item 3 – Loss of Offsite Power

This SR is the performance of a TADOT. This test is a check of AFW automatic pump start on loss of offsite power, undervoltage RCP, and trip of all main feedwater pumps Functions.

TS 3.4.9 Pressurizer

SR 3.4.9.2 Verify capacity of required pressurizer heaters is ≥ 125kW

SR 3.4.9.3 Verify required pressurizer heaters are capable of being powered from an emergency supply

SR 3.4.9.2 is satisfied when the power supplies are demonstrated to be capable of producing the minimum power and the associated pressurizer heaters are verified to be at their design rating. This may be done by testing the power supply output and heater current, or by

performing an electrical check on heater element continuity and resistance. SR 3.4.9.3 demonstrates that the heaters can be manually transferred from the normal to the emergency power supply and energized.

TS 3.5.2 ECCS – Operating

SR 3.5.2.4 Verify each ECCS automatic valve in the flow path that is locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal

SR 3.5.2.5 Verify each ECCS pump starts automatically on an actual or simulated actuation signal

SR 3.5.2.4 and SR 3.5.2.5 demonstrate that each automatic ECCS valve actuates to the required position on an actual or simulated SI signal and that each ECCS pump starts on receipt of an actual or simulated SI signal. The actuation logic is tested as part of ESF Actuation System testing, and equipment performance is monitored as part of the Inservice Testing Program.

TS 3.6.3 Containment Isolation Valves

SR 3.6.3.5 Verify each automatic containment isolation valve that is not locked, sealed or otherwise secured in position, actuates to the isolation position on an actual or simulated actuation signal

Automatic containment isolation valves close on a containment isolation signal to prevent leakage of radioactive material from containment following a DBA. SR 3.6.3.5 ensures that each automatic containment isolation valve will actuate to its isolation position on a containment isolation signal.

TS 3.6.6 Containment Spray and Cooling Systems

SR 3.6.6.7 Verify each containment cooling train starts automatically on an actual or simulated actuation signal

This SR verifies that each containment cooling train actuates upon receipt of an actual or simulated safety injection signal.

TS 3.6.8 Isolation Valve Seal Water (IVSW) System

SR 3.6.8.4 Verify each automatic valve in the IVSW System actuates to the correct position on an actual or simulated actuation signal

This SR verifies that automatic header injection valves actuate to the correct position on a simulated or actual signal.

TS 3.7.4 Auxiliary Feedwater (AFW) System

SR 3.7.4.3 Verify each AFW automatic valve that is not locked, sealed or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal

SR 3.7.4.4 Verify each AFW pump starts automatically on an actual or simulated actuation signal

SR 3.7.4.3 verifies that AFW can be delivered to the appropriate steam generator in the event of any accident or transient that generates an AFW actuation signal, by demonstrating that each automatic valve in the flow path actuates to its correct position on an actual or simulated actuation signal. SR 3.7.4.4 verifies that the AFW pumps will start in the event of any accident or transient that generates an AFW actuation signal by demonstrating that each AFW pump starts automatically on an actual or simulated actuation signal in MODES 1, 2, and 3. In addition to the common failures identified for all SRs in this Section of the SE, one additional common failure that would not have impacted the safety function was identified for these SRs.

TS 3.7.7 Service Water System (SWS)

SR 3.7.7.3 Verify each SWS pump and SWS booster pump starts automatically on an actual or simulated actuation signal

This SR verifies proper automatic operation of the SWS pumps and SWS booster pumps on an actual or simulated actuation signal. The SWS is a normally operating system that cannot be fully actuated as part of normal testing during normal operation.

TS 3.7.9 Control Room Emergency Filtration System (CREFS)

SR 3.7.9.3 Verify each CREFS train actuates on an actual or simulated actuation signal

This SR verifies that each CREFS train starts and operates on an actual or simulated actuation signal.

TS 3.9.3 Containment Penetrations

SR 3.9.3.2 Verify each required containment ventilation valve actuates to the isolation position on an actual or simulated signal

This SR demonstrates that each containment ventilation valve actuates to its isolation position on manual initiation or on an actual or simulated high radiation signal.

Conclusion for Surveillance Requirements with the Same Three Unique Failures

The licensee's review of the applicable HBRSEP surveillance history demonstrated that three unique failures were experienced when performing the procedure and preventive maintenance task required to satisfy these SRs. However, these SRs are among those that the licensee identified the same three unique failure histories for a significant number of SRs. As discussed above, the licensee determined that there was no time based mechanisms involved with the three failures. Therefore, the licensee concluded that as these failures are unique, any

subsequent failure would not result in a significant impact on system/component availability and increasing the surveillance interval will only have a minimal, if any, impact on system availability.

The NRC staff reviewed the proposed change and the licensee's justification for the change, and determined that all actions specified in the GL were completed. The effect on safety would be insignificant, historical data does not contradict this conclusion, the licensee's corrective action for failure was acceptable, and no assumptions in the plant licensing basis would be invalidated. The NRC staff finds the proposed interval extensions acceptable for the listed SRs based on 1) consistency with the guidance provided in the GL 91-04, 2) historical plant maintenance and surveillance data supporting the conclusion, and 3) that the assumptions in the plant licensing-basis would not be invalidated as a result of this revision.

3.1.3 Surveillance Requirements with Other Unique Failures or NRC Staff Requests for Additional Information

TS 3.3.3 Post Accident Monitoring (PAM) Instrumentation

SR 3.3.3.3 Perform TADOT

Table 3.3.3-1 Function 22: PORV Position (Primary)

Table 3.3.3-1, Function 24: Safety Valve Position (Primary)

This SR is the performance of a TADOT of containment isolation valve position indication, PORV position (primary) indication, PORV block valve position (primary) indication, and safety valve position (primary) indication.

The licensee's review of the applicable HBRSEP surveillance history demonstrated that one unique failure each was experienced in the performance of procedures and preventive maintenance tasks required to satisfy these SRs. For Function 22 the licensee also identified one failure that would not have impacted the safety function. Regarding the Function 22 unique failure, a check valve did not seat and piping continually vented during a procedure. The check valve was replaced and retested. Regarding the Function 24 unique failure, an acoustics monitor indicated high noise causing a constant alarm. The pre-amp for the monitor was replaced. The licensee determined that there was no time based mechanisms involved with the failures. Therefore, the licensee concluded that as these failures are unique any subsequent failure would not result in a significant impact on system/component availability and increasing the surveillance interval will only have a minimal, if any, impact on system availability.

The NRC staff reviewed the proposed change and the licensee's justification for the change, and determined that all actions specified in the GL were completed. The effect on safety would be insignificant, historical data does not contradict this conclusion, and no assumptions in the plant licensing basis would be invalidated. The NRC staff finds the proposed interval extensions acceptable for SR 3.3.3.3 for Functions 22 and 24 based on, 1) consistency with the guidance provided in the GL 91-04, 2) historical plant maintenance and surveillance data supporting the conclusion, and 3) that the assumptions in the plant licensing-basis would not be invalidated as a result of this revision.

TS 3.3.5 Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

SR 3.3.5.1 Perform TADOT

This SR is the performance of a TADOT. The test checks trip devices that provide actuation signals directly, bypassing the analog process control equipment.

The licensee's review of the applicable HBRSEP surveillance history demonstrated that two unique failures were experienced in the performance of procedures and preventive maintenance tasks required to satisfy these SRs. The licensee also identified two event driven failures in the procedure and preventive maintenance task that were determined to have no impact on the proposed extension to a 24-month surveillance interval and one failure that would not have impacted the safety function. The first unique failure involved the failure of a microswitch. The microswitch was replaced. The second unique failure involved the failure of a switch in a breaker. The switch was replaced. The licensee determined that there was no time based mechanisms involved with the failures. Therefore, the licensee concluded that as these failures are unique any subsequent failure would not result in a significant impact on system/component availability and increasing the surveillance interval will only have a minimal, if any, impact on system availability.

The NRC staff reviewed the proposed change and the licensee's justification for the change, and determined that all actions specified in the GL were completed. The effect on safety would be insignificant, historical data does not contradict this conclusion, and no assumptions in the plant licensing basis would be invalidated. The NRC staff finds the proposed interval extensions acceptable for SR 3.3.5.1 based on, 1) consistency with the guidance provided in the GL 91-04, 2) historical plant maintenance and surveillance data supporting the conclusion, and 3) the assumptions in the plant licensing-basis would not be invalidated as a result of this revision.

TS 3.4.1 RCS Pressure, Temperature and Flow Departure from Nucleate Boiling (DNB) Limits

SR 3.4.1.4 Verify by precision heat balance that RCS total flow rate is $\geq 97.3 \times 10^6$ lbm/hr

The measurement of the RCS total flow rate by the performance of a calorimetric heat balance once after a refueling outage allows the installed RCS flow instrumentation to be calibrated and verifies that the actual RCS flow is greater than or equal to the minimum required RCS flow rate specified in the Core Operating Limit Reports (COLR). The TS Bases states that it is important to verify the flow after a refueling outages (RFO) when the core has been altered, which may have caused an alteration of flow resistance. (The NRC staff notes that this SR has both calibration and non-calibration elements. While the licensee grouped it with calibration-related SRs, the NRC staff has included it with noncalibration-related SRs in this SE for convenience.)

The NRC staff noted that LAR Attachment 6 provided no failure histories for this SR. The LAR states in part for SR 3.4.1.4, "There is no evaluation required for extension of this SR." However, no justification for this statement was provided. Therefore in SXRB RAI-1, dated August 31, 2017 (Reference 17), the NRC staff requested the licensee to provide the failure histories of the above mentioned SR in accordance with the GL 91-04, or to provide justification as to why it is not required. By letter dated September 28, 2017 (Reference 4), the licensee submitted its response and explained why review of the historical surveillances is not required.

Instrumentation calibrated during refueling outages will remain on an RFO calibration schedule, which will be extended from 18-months to 24-months nominal. This will not result in an increase in duration of the interval between calibration of the equipment and performance of SR 3.4.1.4 since the SR is only performed when the plant is increasing reactor thermal power, following a RFO. The interval between calibrations of outage related equipment and performance of SR 3.4.1.4 will not increase. As an example, pressurizer pressure transmitter PT-456 is currently calibrated at some point during each RFO per SR 3.3.1.10. When the plant is increasing in reactor thermal power following each refueling outage, SR 3.4.1.4 is performed; therefore, the interval between equipment calibration and performance of the SR is no greater than the duration of the RFO. Assuming SR 3.4.1.4 is revised to a 24-month surveillance frequency, PT-456 will still be calibrated during each RFO per SR 3.3.1.10 and SR 3.4.1.4 will still be performed when the plant is increasing reactor thermal power following each RFO; therefore, the duration between equipment calibration and performance of SR 3.4.1.4 will be no greater than the duration of the RFO (typically one or two months). Since there is no change in the interval between calibrations and performance of this SR for outage related calibrated components, review of the historical surveillances is not required.

Based on the above justifications provided by the licensee, the NRC concurs with the licensee that since there is no change in the interval between calibrations and performance of these SR for online and outage related calibrated components, the failure histories of SR 3.4.1.4 are not required to be provided consistent with the guidance provided in GL 91-04, and SRXB RAI-1 is resolved. Similarly, based on the foregoing, NRC staff concludes that increasing to 24 months the above SR in TS 3.4.1 is acceptable.

<u>TS 3.4.11 Pressurizer Power Operated Relief Valves (PORVs)</u>

SR 3.4.11.3 Perform a complete cycle of each solenoid air control valve and check valve on the nitrogen accumulators in PORV control system

SR 3.4.11.4 Verify accumulators are capable of operating PORVs through a complete cycle

The surveillance test intervals of these SRs are being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. SR 3.4.11.3 operates the solenoid air control valves and check valves on the nitrogen accumulators, ensuring that the PORV control system actuates properly when called upon. SR 3.4.11.4 demonstrates that the accumulators are capable of supplying sufficient nitrogen to operate the PORVs if they are needed for RCS pressure control, and normal nitrogen and the backup instrument air systems are not available.

The licensee's review of the applicable HBRSEP surveillance history demonstrated that one common unique failure was experienced in the performance of procedures and preventive maintenance tasks required to satisfy these SRs. The licensee also identified one common failure that would not have impacted the safety function. A check valve did not seat, and piping continually vented. This was a failure to meet SR 3.4.11.3. The check valve was replaced and retested. The licensee determined that there was no time based mechanisms involved with the failure. Therefore, the licensee concluded that as this failure is unique any subsequent failure would not result in a significant impact on system/component availability and increasing the surveillance interval will only have a minimal, if any, impact on system availability.

The NRC staff reviewed the proposed change and the licensee's justification for the change and determined that all actions specified in the GL were completed. The effect on safety would be insignificant, historical data does not contradict this conclusion, the licensee's corrective action for failure was acceptable, and no assumptions in the plant licensing basis would be invalidated. The NRC staff finds the proposed interval extensions acceptable for SR 3.4.11.3 and SR 3.4.11.4 based on, 1) consistency with the guidance provided in the GL 91-04, 2) historical plant maintenance and surveillance data supporting the conclusion, and 3) that the assumptions in the plant licensing-basis would not be invalidated as a result of this revision.

TS 3.6.8 Isolation Valve Seal Water (IVSW) System

SR 3.6.8.5 Verify the IVSW dedicated nitrogen bottles will pressurize the IVSW tank to ≥ 46.2 psig

SR 3.6.8.6 Verify total IVSW seal header flow rate is ≤ 124 cc/minute

The surveillance test intervals of these SRs are being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. SR 3.6.8.5 verifies the capability of the dedicated nitrogen bottles to pressurize the IVSW system independent of the Plant Nitrogen System. SR 3.6.8.6 verifies the integrity of the IVSW seal boundary to provide assurance that the design leakage value required for the system to perform its sealing function is not exceeded.

The licensee's review of the applicable HBRSEP surveillance history demonstrated that one common unique failure was experienced in the performance of procedures and preventive maintenance tasks required to satisfy these SRs. The licensee also identified three common event driven failures in the procedure and preventive maintenance task that were determined to have no impact on the proposed extension to a 24-month surveillance interval and six common failures that would not have impacted the safety function. Regarding the unique failure, the system leakrate exceeded the test procedure acceptance criteria. The leak was identified and repaired. The licensee determined that there was no time based mechanisms involved with the failure. Therefore, the licensee concluded that as this failure is unique, any subsequent failure would not result in a significant impact on system/component availability and increasing the surveillance interval will only have a minimal, if any, impact on system availability.

The NRC reviewed the proposed change and the licensee's justification for the change, and determined that all actions specified in the GL were completed. The effect on safety would be insignificant, historical data does not contradict this conclusion, and no assumptions in the plant licensing basis would be invalidated. The NRC staff finds the proposed interval extensions acceptable for SR 3.6.8.5 and SR 3.6.8.6 based on, 1) consistency with the guidance provided in the GL 91-04, 2) historical plant maintenance and surveillance data supporting the conclusion, and 3) that the assumptions in the plant licensing-basis would not be invalidated as a result of this revision.

TS 3.8.1 AC Sources – Operating (Background)

The NRC staff notes that several of the TS 3.8.1 SRs could have been included in Section 3.1.1 or Section 3.1.2 of this SE because the licensee identified no unique failures or the licensee identified the same unique failures that were the subject of General-RAI-1. However, the NRC

staff considered certain design features and more frequent SRs in its review so all TS 3.8.1 SRs are included in Section 3.1.3 of the SE.

The HBRSEP 1E 4160 V system is divided into five buses. Bus Number 3 is normally connected to the 115 kV system via the bus main breaker and Startup Transformer Number 2. During normal operation, Buses 1, 2, and 4 are normally connected to the generator leads via bus main breakers and Unit Auxiliary Transformer Number 2. The 4160 V Bus Number 5 is connected to 4160 V Bus Number 4. Buses 1 and 2 or Buses 3 and 4 can be tied together via bus tie breakers. A generator lockout causes Buses 1, 2, and 4 to be automatically transferred to the 115 kV system. Bus supply and bus tie circuit breakers are equipped with stored energy closing mechanisms to provide fast dead bus transfers. All 4160 V auxiliaries are split between Buses 1, 2, 4, and 5. In addition, 4.16 kV Buses 1, 4, and 5 each serves one 4160 to 480 V Station Service Transformer and 4.16 kV Buses 2 and 3 each serves two Station Service Transformers. ESF equipment circuits are connected to 480 V Buses E1 and E2. The normal source of power for Bus E1 is the Unit 2 Auxiliary Transformer through Station Service Transformer 2F. The normal source of power for Bus E2 is the 115 kV system through Startup Transformer 2 and Station Service Transformer 2G. One emergency DG is connected to Bus E1 and the other to Bus E2. A DG will be automatically started and connected to its bus if voltage on its associated bus is lost. The NRC staff noted that this design provides substantial redundancy in AC power sources. The DGs are infrequently operated; thus, the risk of wear related degradation is minimal. The NRC staff also noted that historical testing and surveillance testing during operation prove the ability of the DGs to start and operate under various load conditions.

The NRC staff also noted that other more frequent testing of the AC sources is performed as follows:

Verifying correct breaker alignment and indicated power availability for each required offsite circuit every 7 days (i.e., SR 3.8.1.1);

Verifying the DG starting and load carrying capability is demonstrated every 31 days (i.e., SRs 3.8.1.2 and 3.8.1.3), and ability to continuously supply makeup fuel oil is also demonstrated every 31 days (i.e., SR 3.8.1.6);

Verifying the ability of each DG to reach rated speed and frequency within required time limits every 184 days (i.e., SR 3.8.1.7) help to ensure the availability of the standby electrical power supply to mitigate DBAs and transients and to maintain the unit in a safe shutdown condition;;

Verifying the necessary support for DG start and operation as well as verifying the DG factors that are subject to degradation due to aging, such as fuel oil quality, (i.e., SRs 3.8.1.4, 3.8.1.5, 3.8.3.1, 3.8.3.2, 3.8.3.3, and 3.8.3.4) are required every 31 days and/or prior to addition of new fuel oil.

TS 3.8.1 AC Sources – Operating

SR 3.8.1.8 Verify each DG rejects a load greater than or equal to its associated single largest post-accident load and does not trip on overspeed

SR 3.8.1.10 Verify on an actual or simulated ESF actuation signal each DG auto-starts from standby condition

The surveillance test intervals of these SRs are being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. SR 3.8.1.8 demonstrates the DG load response characteristics and capability to reject the largest single load without exceeding the overspeed trip. SR 3.8.1.10 demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time (10 seconds) from the design basis actuation signal (loss of coolant accident signal) and operates for 5 or more minutes.

The licensee's review of the applicable HBRSEP surveillance history demonstrated that three unique failures were experienced when performing the procedure and preventive maintenance task required to satisfy these SRs. However, these SRs are among those that the licensee identified the same three unique failure histories for a significant number of SRs. As previously noted, the licensee also identified two common event driven failures in the procedure and preventive maintenance task that were determined to have no impact on the proposed extension to a 24-month surveillance interval and 10 failures that would not have impacted the safety function. As discussed above, the licensee determined that there was no time based mechanisms involved with the three unique failures. Therefore, the licensee concluded that as these failures are unique any subsequent failure would not result in a significant impact on system/component availability and increasing the surveillance interval will only have a minimal, if any, impact on system availability.

The NRC staff reviewed the proposed change and the licensee's justification for the change, and determined that all actions specified in the GL were completed. The effect on safety would be insignificant, historical data does not contradict this conclusion, the licensee's corrective action for failure was acceptable, and no assumptions in the plant licensing basis would be invalidated. The NRC staff finds the proposed interval extensions acceptable for SR 3.8.1.8 and SR 3.8.1.10 based on, 1) consistency with the guidance provided in the GL 91-04, 2) historical plant maintenance and surveillance data supporting the conclusion, and 3) that the assumptions in the plant licensing-basis would not be invalidated as a result of this revision.

TS 3.8.1 AC Sources – Operating

SR 3.8.1.9 Verify on an actual or simulated loss of offsite power signal: Deenergizing of the emergency buses; load shedding from the emergency buses; and DG auto-starts from standby condition

SR 3.8.1.15 Verify on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated ESF actuation signal: De-energizing of the emergency buses; load shedding from the emergency buses; and DG auto-starts from standby condition

The surveillance test intervals of these SRs are being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. SR 3.8.1.9 demonstrates the as designed operation of the standby power sources during loss of the offsite source. The SR verifies all actions encountered from the loss of offsite power, including shedding of the nonessential loads and energization of the emergency buses and respective loads from the DG. It further demonstrates the capability of the DG to automatically achieve the required voltage and frequency within the specified time. SR 3.8.1.15 demonstrates the DG operation during a loss of offsite power actuation test signal in conjunction with an ESF actuation signal.

The licensee's review of the applicable HBRSEP surveillance history demonstrated that five unique failures were experienced when performing the procedure and preventive maintenance task required to satisfy these SRs. The licensee also identified four common event driven failures in the procedure and preventive maintenance task that were determined to have no impact on the proposed extension to a 24-month surveillance interval and 11 common failures that would not have impacted the safety function. However, for three of the unique failures, these SRs are among those that the licensee identified the same three unique failure histories for a significant number of SRs. As discussed above, the licensee determined that there was no time based mechanisms involved with the three failures. For the fourth unique failure, two breakers immediately tripped open when closed. The licensee found that a microswitch contact closed causing the trip signal to be locked in. The licensee replaced the microswitch. For the fifth unique failure, a breaker would not close due to the failure of a switch. The licensee replaced the switch. The licensee determined that there was no time based mechanisms involved with these two additional unique failures. Therefore, the licensee concluded that as these five failures are unique any subsequent failure would not result in a significant impact on system/component availability and increasing the surveillance interval will only have a minimal, if any, impact on system availability.

The NRC staff reviewed the proposed change and the licensee's justification for the change, and determined that all actions specified in the GL were completed. The effect on safety would be insignificant, historical data does not contradict this conclusion, the licensee's corrective action for failure was acceptable, and no assumptions in the plant licensing basis would be invalidated. The NRC staff finds the proposed interval extensions acceptable for SR 3.8.1.9 and SR 3.8.1.15 based on, 1) consistency with the guidance provided in the GL 91-04, 2) historical plant maintenance and surveillance data supporting the conclusion, and 3) that the assumptions in the plant licensing-basis would not be invalidated as a result of this revision.

TS 3.8.1 AC Sources – Operating

SR 3.8.1.12 Verify each DG operating at a power factor ≤ 0.9 operates for ≥ 24 hours

SR 3.8.1.13 Verify each DG starts and achieves, in ≤ 10 seconds, voltage ≥ 467 V, and frequency ≥ 58.8 Hz, and after steady state conditions are reached, maintains voltage ≥ 467 V and ≤ 493 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz

The surveillance test intervals of these SRs are being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. SR 3.8.1.12 demonstrates that the DGs can start and run continuously at full load capability for an interval of not less than 24 hours, 1.75 or more hours of which is at a load equivalent to 110% of the continuous duty rating and the remainder of the time at a load equivalent to the continuous duty rating of the DG. SR 3.8.1.13 demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal surveillances, and achieve the required voltage and frequency within 10 seconds.

The licensee's review of the applicable HBRSEP surveillance history demonstrated that two common unique failures were experienced when performing the procedure and preventive maintenance task required to satisfy these SRs. For SR 3.8.1.12 the licensee also identified one event driven failure in the procedure and preventive maintenance task that was determined to have no impact on the proposed extension to a 24-month surveillance interval and 12 failures that would not have impacted the safety function. For SR 3.8.1.13 the licensee also identified two event driven failures in the procedure and preventive maintenance task that were determined to have no impact on the proposed extension to a 24-month surveillance interval, 18 failures that would not have impacted the safety function, and two failures that would have been detected by other more frequent testing. For the first common unique failure, an emergency DG output breaker opened during a load test. The licensee determined the breaker opened due to a failed overcurrent protection relay. The licensee replaced the relay. For the second common unique failure, a fuel oil transfer pump failed while running in support of an emergency DG. The licensee determined that the pump failed due to the failure of the fuel oil transfer pump motor, which failed due to lack of periodic motor replacement. The licensee replaced the motor and instituted a motor replacement frequency (every 4 years) to preclude future motor failures. The licensee determined that there was no time based mechanisms involved with these two failures. The NRC staff notes that the second unique failure occurred in 2005. While the prior lack of preventative maintenance on the pump motor could be interpreted as a time based failure mechanism, the institution of the motor replacement frequency has prevented similar subsequent failures and thus the one documented failure can be considered unique. Therefore, the licensee concluded that as these failures are unique any subsequent failure would not result in a significant impact on system/component availability and increasing the surveillance interval will only have a minimal, if any, impact on system availability.

The NRC staff reviewed the proposed change and the licensee's justification for the change, and determined that all actions specified in the GL were completed. The effect on safety would be insignificant, historical data does not contradict this conclusion, the licensee's corrective action for failure was acceptable, and no assumptions in the plant licensing basis would be invalidated. The NRC staff finds the proposed interval extensions acceptable for SR 3.8.1.12 and SR 3.8.1.13 based on, 1) consistency with the guidance provided in the GL 91-04, 2) historical plant maintenance and surveillance data supporting the conclusion, and 3) that the assumptions in the plant licensing-basis would not be invalidated as a result of this revision.

TS 3.8.1 AC Sources – Operating

SR 3.8.1.16 Verify automatic transfer capability of the 4.16kV bus 2 and the 480V Emergency bus 1 loads from the Unit auxiliary transformer to the start up transformer

The surveillance test interval of this SR is being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. SR 3.8.1.16 demonstrates the automatic transfer capability of the 4.16kV bus 2 and the 480V Emergency bus 1 loads from the auxiliary transformer to the startup transformer. This demonstrates the operability of the offsite circuit network to power the shutdown loads.

The licensee's review of the applicable HBRSEP surveillance history demonstrated that no unique failures were experienced when performing the procedure and preventive maintenance task required to satisfy this SR. The licensee did identify one event driven failure in the procedure and preventive maintenance task that was determined to have no impact on the proposed extension to a 24-month surveillance interval and one failure that would not have impacted the safety function. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Therefore, based on the history of system performance, the licensee concluded that the impact of this change on safety, if any, is small.

The NRC staff reviewed the proposed change and the licensee's justification for the change, and determined that all actions specified in the GL were completed. The effect on safety would be insignificant, historical data does not contradict this conclusion, and no assumptions in the plant licensing basis would be invalidated. The NRC staff finds the proposed interval extensions acceptable for SR 3.8.1.16 based on, 1) consistency with the guidance provided in the GL 91-04, 2) historical plant maintenance and surveillance data supporting the conclusion, and 3) that the assumptions in the plant licensing-basis would not be invalidated as a result of this revision.

TS 3.8.4 DC Sources – Operating (Background)

Similar to TS 3.8.1, the NRC staff notes that the TS 3.8.4 SRs could have been included in Sections 3.1.1 of this SE because the licensee identified no unique failures. However, the NRC staff considered certain more frequent SRs in its review, so the TS 3.8.4 SRs are included in Section 3.1.3 of the SE. In addition to the SRs for DC sources discussed below, other more frequent testing of the DC sources is performed as follows:

> SR 3.8.4.1 and SR 3.8.6.1 are performed every 7 days to verify battery terminal voltage and pilot cell float voltage, electrolyte level and specific gravity, respectively. SR 3.8.6.2 and SR 3.8.6.3 are performed every 92 days to verify each cell float voltage, each cell electrolyte level, each cell specific gravity, and pilot cell temperature. These more frequent surveillances will provide prompt identification of substantial degradation or failure of the battery and/or battery chargers.

TS 3.8.4 DC Sources – Operating

SR 3.8.4.3 Remove visible terminal corrosion, verify battery cell to cell and terminal connections are clean and tight, and are coated with anti-corrosion material

SR 3.8.4.4 Verify each battery charger supplies ≥ 300 amps at ≥ 125 V for ≥ 4 hours

SR 3.8.4.5 Verify battery capacity is adequate to supply, and maintain in OPERABLE status, the required emergency loads for the design duty cycle when subjected to a battery service test

The surveillance test intervals of these SRs are being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the 25% grace period. SR 3.8.4.3 includes visual inspection of intercell, intertier, and terminal connections to provide an indication of physical damage or abnormal deterioration that could indicate degraded battery condition. The removal of visible corrosion is a preventive maintenance SR. SR 3.8.4.4 verifies each battery charger supplies 300 amps or greater at 125 V or greater for 4 or more hours. SR 3.8.4.5 verifies battery capacity is adequate to supply, and maintain in OPERABLE status, the required emergency loads for the design duty cycle when subjected to a battery service test.

The licensee's review of the applicable HBRSEP surveillance history demonstrated that no unique failures were experienced when performing the procedure and preventive maintenance task required to satisfy these SRs. For SR 3.8.4.3 the licensee did identify one failure that would not have impacted the safety function. For SR 3.8.4.4 the licensee did identify two failures that would not have impacted the safety function. For SR 3.8.4.5 the licensee did identify two event driven failures in the procedure and preventive maintenance task that were determined to have no impact on the proposed extension to a 24-month surveillance interval and three failures that would not have impacted the safety function. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Therefore, based on the history of system performance, the licensee concluded that the impact of this change on safety, if any, is small.

The NRC staff reviewed the proposed change and the licensee's justification for the change, and determined that all actions specified in the GL were completed. The effect on safety would be insignificant, historical data does not contradict this conclusion, and no assumptions in the plant licensing basis would be invalidated. The NRC staff finds the proposed interval extensions acceptable for SR 3.8.4.3, SR 3.8.4.4, and SR 3.8.4.5 based on, 1) consistency with the guidance provided in the GL 91-04, 2) historical plant maintenance and surveillance data supporting the conclusion, and 3) that the assumptions in the plant licensing-basis would not be invalidated as a result of this revision.

TS 5.5.11 Ventilation Filter Testing Program

Ventilation Filter Testing Program (VFTP) - This program provides controls for implementation of the following required testing of Engineered Safety Feature (ESF) ventilation filter systems at the frequencies specified in Positions C.5 and C.6 of

> Regulatory Guide 1.52, Revision 2, March 1978, and conducted in general conformance with ANSI N510-1975 or N510-1980.

TS Section 5.5.11 requires testing at frequencies specified in RG 1.52, Revision 2, "Design, Testing, and Maintenance Criteria for Post Accident Engineered-Safety-Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants" (Reference 18). RG 1.52 Revision 2, Regulatory Position C.5 states that at least once per 18 months an in-place High Efficiency Particulate Air (HEPA) filter Dioctyl Phthalate (DOP) penetration test and an in-place test of activated carbon adsorber filters bypass leakage with a halogenated hydrocarbon refrigerant should be performed. Regulatory Position C.6 states that at least once per 18 months a sample of the activated carbon adsorber should be laboratory tested for iodine decontamination efficiency.

The required interval of these tests is being increased from once every 18 months to once every 24 months, for a maximum interval of 30 months including the TS SR 3.0.2 allowed 25% interval extension. These tests of the ESF ventilation system filter units verify that they remain capable of providing the designed protection from airborne radionuclides.

LAR Attachment 8 states that the exception to the RG 1.52 interval is explicitly addressed in the change to TS 5.5.11. The first paragraph within TS 5.5.11 is revised to state (inserted text shown underlined):

> This program provides controls for implementation of the following required testing of Engineered Safety Feature (ESF) ventilation filter systems at the frequencies specified in Positions C.5 and C.6 of Regulatory Guide 1.52, Revision 2, March 1978, <u>except that the testing specified at a frequency of 18 months is required at a frequency of 24 months</u>, and conducted in general conformance with ANSI N510-1975 or N510-1980.

The LAR further states that the ventilation filter (HEPA and charcoal) testing will continue to be performed in accordance with the other frequencies specified in RG 1.52, specifically: (1) on initial installation and (2) following painting, fire, or chemical release in any ventilation zone communicating with the system. Additionally, RG 1.52 requires that a sample of the charcoal adsorber be removed and tested after each 720 hours of system operation, and that an in-place charcoal test be performed following removal of these samples if the integrity of the adsorber section was affected. The LAR states that the proposed amendment request will not change the commitment to perform the above tests.

The licensee's review of the applicable HBRSEP surveillance history demonstrated that one unique failure was experienced when performing the procedure and preventive maintenance task required to satisfy this TS. The licensee also identified six failures that would not have impacted the safety function. A filter test failed to meet an efficiency acceptance criterion. The licensee determined that several filter cells were degraded due to moisture. The carbon in the cells was replaced and the retest was completed satisfactorily. The licensee determined that there were no time based mechanisms involved with the failure. Therefore, the licensee concluded that as this failure is unique any subsequent failure would not result in a significant impact on system/component availability and increasing the surveillance interval will only have a minimal, if any, impact on system availability.

The NRC staff reviewed the proposed change and the licensee's justification for the change, and determined that all actions specified in the GL were completed. The effect on safety would be insignificant, historical data does not contradict this conclusion, the licensee's corrective

action for failure was acceptable, and no assumptions in the plant licensing basis would be invalidated. In addition, in Revision 3 of RG 1.52, dated June 2001 (Reference 19) the general acceptability of this longer testing interval was recognized with the change in the recommended frequency to at least once each 24 months. The NRC staff finds the proposed interval extensions acceptable for TS 5.5.11 based on, 1) consistency with the guidance provided in the GL 91-04, 2) historical plant maintenance and surveillance data supporting the conclusion, and 3) that the assumptions in the plant licensing-basis would not be invalidated as a result of this revision.

TS 5.5.17 Control Room Envelope Habitability Program

5.5.17(d) Measurement, at designated locations, of the CRE pressure relative to external areas adjacent to the CRE boundary during the pressurization mode of operation by one train of the CREFS, operating at the flow rate required by the VFTP, at a frequency of 18 months on a STAGGERED TEST BASIS. The results shall be trended and used as part of the assessment of the CRE boundary.

TS 5.5.17(d) requires measurement of CRE pressure relative to all external areas adjacent to the CRE boundary during the pressurization mode of operation by the CREFS at a frequency of 18 months, on a staggered test basis. The test interval of this TS is being increased from once every 18 months to once every 24 months on a staggered test basis, for a maximum interval of 30 months including the 25% grace period. The CRE Habitability Program was placed in the HBRSEP TSs as part of Amendment No. 219 dated July 23, 2008 (Reference 20), which adopted Technical Specification Task Force (TSTF)-448, Revision 3, "Control Room Habitability" (Reference 21). The TSTF model amendment wording allowed for plant-specific selection of an appropriate test interval, typically that of the reactor refueling cycle.
TS 5.5.17(c)(i) requires determination of the unfiltered leakage past the CRE boundary into the CRE in accordance with the testing methods and at the frequencies specified in Sections C.1 and C.2 of RG 1.197, "Demonstrating Control Room Envelope Integrity at Nuclear Power Reactors," Revision 0, May 2003 (Reference 22). TS 5.5.17(c)(ii) requires assessing CRE habitability at the frequencies specified in Sections C.1 and C.2 of RG 1.197, Revision 0. In addition, Figure 1 in RG 1.197 has an assessment frequency of 3 years. The proposed change to TS 5.5.17(d) would result in the two trains being tested on a 48 month or 4 year frequency instead of 3 year frequency indicated by Figure 1 in RG 1.197. In SBPB RAI-1 (Reference 17), the licensee was requested to address the impact of the proposed change to TS 5.5.17(d) on TS 5.5.17(c) and also identify any deviations from RG 1.197 that may be necessary.

By letter dated September 28, 2017 (Reference 4), the licensee submitted its response to SBPB RAI-1, summarized as follows:

> RG 1.197 Figure 1 has an assessment frequency of 3 years following an integrated leakage test. Figure 1 also shows that an integrated leakage test is to be scheduled 3 years following an assessment. Following RG 1.197 Figure 1 flow chart, the minimum possible years between program assessments is 6 years (with exception to the initial assessments performed 3 years after the initial baseline inleakage test). The tests to measure pressures in the adjacent areas to the CRE to satisfy TS 5.5.17(d) are performed in conjunction with Control Room Emergency Ventilation System Filter Performance Testing required by TS 5.5.11. However, the test to satisfy TS 5.5.17(d) are performed on a staggered basis with 'A' Train Control Room Emergency Filtration System tested in EVEN number outages, and 'B' Train Control Room Emergency Filtration System tested in ODD number outages.

> By extending the frequency of testing adjacent area pressures with each Control Room emergency pressurization train from 3 years to 4 years, data would still be collected (for both trains) in that 6 year time frame that the program assessment is required to evaluate per RNP [H. B. Robinson Nuclear Plant] TS 5.5.17(d). That data will be compared to, and trended against, historical adjacent area pressures of adjacent area pressures to determine if any CRE deficiencies are apparent. Therefore, no deviations to RG 1.197 specified frequencies outlined in Sections C.1, C.2, or Figure 1 will be taken.

The NRC staff notes that the integrated inleakage tracer gas test periodicity is 6 years with a self-assessment at 3 years in between the integrated leak rate tests, thus making the periodicity in between assessments also 6 years (with exception to the initial assessment performed 3 years after the initial baseline integrated leakage test). With the proposed increase in testing the adjacent area test pressures from 18 months to 24 months on a staggered test basis, the total number of tests for adjacent area pressures would decrease in the 6 years in between assessments. However, adjacent area pressures would still be taken per TS 5.5.17(d), at least once for each train of the CREFS in the 6-year time frame. There are ongoing CRE maintenance program activities that are also used in the assessment, in addition to the history of the adjacent pressure readings. Though the 3-year assessment before and after each integrated leak test accommodates readings to be taken for each train operation, the NRC staff also notes that RG 1.197 does not stipulate a specific frequency for the adjacent area pressure measurements. Therefore, the NRC staff concludes that the licensee response to SBPB RAI-1(a) is reasonable and acceptable.

The NRC staff also noted that regarding in TS 5.5.11, "Ventilation Filter Testing Program," the LAR stated that the change in filter testing frequency from 18 months to 24 months is an exception to RG 1.52, Revision 2. In Attachment 5, "Summary of License Commitments," to the LAR, the licensee made a commitment that the discussion regarding the current conformance to RG 1.52 in UFSAR Section 1.8, "Conformance to NRC Regulatory Guides" will be revised as a result of the LAR to include the exception to RG 1.52. In SBPB RAI-1(b), the licensee was requested to clarify if a similar discussion regarding conformance to RG 1.197 would be included in UFSAR Section 1.8. In response to the RAI (Reference 4), the licensee stated that RG 1.197 is not currently documented in the HBRSEP UFSAR unlike RG 1.52 and that RG 1.197 was documented in the TSs only. Since the exception to RG 1.197 is adequately documented in the revised TSs, the NRC staff concludes that SBPB RAI-1(b) is resolved.

The licensee's review of the applicable HBRSEP surveillance history demonstrated that no unique failures were experienced when performing the procedure and preventive maintenance task required to satisfy this TS. As such, the impact, if any, on system availability is minimal from the proposed change to a 24-month testing frequency. Therefore, based on the history of system performance, the licensee concluded that the impact of this change on safety, if any, is small.

The NRC staff reviewed the proposed change and the licensee's justification for the change, and determined that all actions specified in the GL were completed. The effect on safety would be insignificant, historical data does not contradict this conclusion, and no assumptions in the plant licensing basis would be invalidated. The NRC staff finds the proposed interval extensions acceptable for TS 5.5.17(d) based on, 1) consistency with the guidance provided in the GL 91-04, 2) historical plant maintenance and surveillance data supporting the conclusion, and

3) that the assumptions in the plant licensing-basis would not be invalidated as a result of this revision.

3.2 Calibration Related Changes

The licensee addressed calibration changes in four different portions of its submittals. (1) LAR Enclosure, Section 2, "Channel Calibration Changes," addresses the seven items identified in GL 91-04, Enclosure 2, to be performed for calibration related changes. (2) LAR Attachment 7, "Detailed Drift Evaluation Methods," presents the licensee's drift evaluation methods used to address and confirm conformance to the guidelines of GL 91-04. (3) The licensee separately submitted a representative instrument calculation that was updated as part of the LAR (Reference 2). (4) LAR Attachment 6, "Review of Historical Surveillance Records for Instrumentation," presents the licensee's review of historical information performed to address GL 91-04, Item 1. In sections 3.2.1 to 3.2.4 of this SE, the NRC staff presents a summary of the each portion of the licensee's submittal and the NRC staff evaluation of each of these portions. The NRC staff notes that the 2nd through 4th portions of the submittals listed above both support and overlap the 1st portion of the submittals. The SE makes conclusions applicable to the portion of the submittal reviewed in each section, with the understanding that collectively they demonstrate conformance to the guidelines of GL 91-04.

3.2.1 Evaluation of GL 91-04, Enclosure 2 Actions

As described in Section 2.3.2 of this SE, GL 91-04, Enclosure 2 identifies seven actions to be performed for calibration-related changes. Calibration-related changes are addressed in LAR Enclosure, Section 4.2, "Channel Calibration Changes," and the LAR Attachment 6. LAR Enclosure, Section 4.2 designates each of the GL 91-04, Enclosure 2 actions as steps and provides an evaluation of each step. This SE section summarizes the licensee's evaluation of each step, using the licensee's designation, and the corresponding NRC staff evaluation.

GL 91-04, Enclosure 2, Step 1

Confirm that instrument drift as determined by as-found and as-left calibration data from surveillance and maintenance records has not, except on rare occasions, exceeded acceptable limits for a calibration interval.

Licensee Evaluation of GL 91-04, Enclosure 2, Step 1:

The licensee evaluation included defining the application of the following phrase in GL 91-04, Enclosure 2, Step 1: (i) "exceeded acceptable limits" and (ii) "except on rare occasions." The licensee defined and addresses those two terms as follows.

(i) Exceeded Acceptable Limits

The licensee stated that uncertainty/setpoint calculations are intended to ensure the analytical limits are not exceeded. Typically, as-found values are determined from the calculations for each component of an instrument loop. Finding equipment within those as-found values ensures the total loop uncertainty (TLU) is not exceeded and therefore, the analytical limit was not challenged. Therefore, equipment associated with uncertainty/setpoint calculations will use the calculated as-found tolerances as the acceptable limits for this evaluation.

When there is no setpoint calculation, the licensee uses Allowable Value per the TS. Additionally, as-found values, which are found to be out-of-tolerance in a conservative direction with respect to Allowable Values, will not be considered to exceed acceptable limits. The licensee stated that the additional conservatism does not impair the equipment functionality. However, as a part of the corrective action plan, these out of tolerances are routinely reviewed by the licensee to determine the condition of the device in accordance with the plant procedures.

Hence, the functions that have a trip setpoint calculation will be considered by the licensee to have exceeded acceptable limits if the out of tolerance was found greater than the calculated as-found tolerance in the direction of the Allowable Value (i.e., in a non-conservative direction).

The licensee stated that the TS functions which have no setpoint or Allowable Value, such as PAM functions, typically provide the operator with indication to perform manual action specified in the unit Emergency Operating Procedures. These functions typically have action setpoints associated with them. These action setpoints are determined using the calculated uncertainty values. If components are outside of the calculated uncertainty values, it could have an adverse effect on operator actions. Again, finding components within the calculated as-found tolerances ensures the TLU and Total Device Uncertainty have not been exceeded. Therefore, for components that have an associated uncertainty calculation, the licensee will use the calculated as-found values as the acceptable limits.

The licensee stated that functions that have no associated uncertainty calculation may use the calibration tolerance as the acceptable limits or another definition as explained and evaluated in Attachment 6 of the LAR.

(ii) Except on Rare Occasions

The licensee reviewed approximately 10 years of surveillance data, as documented in LAR Attachment 6 and evaluated by the NRC staff in Section 3.2.4 of the this SE.

The licensee stated that generally, instrumentation that is repeatedly found to exceed its as-found tolerances will require corrective actions. These corrective actions could be to replace the equipment, perform a modification, setpoint change or other actions. Therefore, it is not expected that instrumentation will be continually found to exceed acceptable limits. If instruments were found to exceed acceptable limits on two consecutive occurrences it is indicative of more than rare occasion. If a specific exceedance is in a conservative direction then it is not considered unacceptable as explained earlier.

The licensee further stated that additionally, instruments that were found to exceed their allowable value on two or more occasions over the review period were inspected to determine if the problem was corrected. If the problem was corrected and acceptable limits were no longer exceeded, the issue was no longer considered to be a factor in the determination to extend the calibration interval. If the problem was not corrected it was considered by the licensee to be more than a rare occasion.

NRC Staff Evaluation:

The NRC staff reviewed the licensee's assessment of as-found and as-left calibration data from surveillance and maintenance records and finds it acceptable. The NRC staff review is documented in Section 3.2.4 of this SE. In RAI EICB-1, the NRC staff requested the licensee to

explain the evaluation method if a failure happened in the first surveillance after replacement of the instrument. In its response dated January 8, 2018 (Reference 5), the licensee explained that a single good or bad reading after repair does not determine the acceptability. The acceptance is based on performance prior to failure and the performance of similar instruments. The acceptability is based on a case by case basis. Staff agrees with the licensee evaluation of such occurrences. Based on the foregoing, the NRC staff finds the licensee has adequately addressed GL 91-04, Enclosure 2, Step 1.

GL 91-04, Enclosure 2, Step 2:

Confirm that the values of drift for each instrument type (make, model, and range) and application have been determined with a high probability and a high degree of confidence. Provide a summary of the methodology and assumptions used to determine the rate of instrument drift with time based upon historical plant calibration data.

Licensee Evaluation of GL 91-04, Enclosure 2, Step 2:

The licensee developed an Engineering Change specifically to establish the methodology used to collect instrument drift data, evaluate the data for outliers, test the data for statistical relevance, and perform the mean drift extension. The methodology is based on Electric Power Research Institute (EPRI) Technical Report (TR)-103335. While EPRI TR-103335 has not been endorsed by the NRC, as noted by the licensee, the NRC staff has previously accepted the use of drift evaluation methods based on EPRI TR-103335 (References 13 and 16). The licensee's use of Revision 1 and Revision 2 of EPRI TR-103335 is further discussed and evaluated in Section 3.2.2 of this SE.

As part of this project, instruments that are calibrated every 18 months, but are also subject to a SR COT and SR Channel Check were not included in the drift analysis. For components that were evaluated for drift, the licensee determined that the magnitude of instrument drift has been determined with a high probability and a high degree of confidence for a bounding calibration interval of 30 months for each instrument type (make, model, and range) and application that performs a safety function.

NRC Staff Evaluation:

The staff reviewed the licensee assessment of drift values and finds it acceptable. The COT and Channel Check will not change with this project, and will continue to ensure that instruments are capable of performing their intended functions within acceptable limits. COTs are typically performed quarterly (92 days). The COT does not include transmitters (sensors). The typical COT disconnects the transmitter from the rest of the instrument loop and injects a simulated signal in the instrument loop. Therefore, the transmitters are only calibrated during the 18-month surveillances (current refueling interval). In its RAI response dated January 8, 2018 (Reference 5), the licensee explained that the transmitters will not be excluded from drift analysis. COTs are used to ensure operability of safety-related equipment; therefore, it does not verify functionality of components in the instrument loop that do not perform those functions. Specifically, the COT does not typically include verification of indicators, computer inputs, or components used for control, even if they are in the loop the COTs are being performed. The staff agrees with the licensee evaluation of instrument loop components. Based on the foregoing, the NRC staff finds the licensee has adequately addressed GL 91-04, Enclosure 2, Step 2.

GL 91-04, Enclosure 2, Step 3:

Confirm that the magnitude of instrument drift has been determined with a high probability and a high degree of confidence for a bounding calibration interval of 30 months for each instrument type (make, model, and range) and application that performs a safety function. Provide a list of the channels by TS sections that identifies these instrument applications.

Licensee Evaluation of GL 91-04, Enclosure 2, Step 3:

The licensee has performed an evaluation to determine the magnitude of instrument drift for a bounding calibration interval of 30 months for each instrument type (make, model, and range) and application that performs a safety function. The evaluation justifies taking exception for certain instruments based on factors including: channel operability tests performed more frequently, construction of component, and history of little to no drift. For components that were evaluated for drift, the licensee determined that the magnitude of instrument drift has been determined with a high probability and a high degree of confidence for a bounding calibration interval of 30 months for each instrument type (make, model, and range) and application that performs a safety function.

The licensee also included a list of instrument loops for which the drift analysis has been performed.

NRC Evaluation:

The NRC staff agrees with the licensee's evaluation and finds the licensee's evaluation conclusions acceptable. Accordingly, the NRC staff finds the licensee has adequately addressed GL 91-04, Enclosure 2, Step 3.

GL 91-04, Enclosure 2, Step 4:

Confirm that a comparison of the projected instrument drift errors has been made with the values of drift used in the setpoint analysis. If this results in revised setpoints to accommodate larger drift errors, provide proposed TS changes to update trip setpoints. If the drift errors result in a revised safety analysis to support existing setpoints, provide a summary of the updated analysis conclusions to confirm that safety limits and safety analysis assumptions are not exceeded.

Licensee Evaluation of GL 91-04, Enclosure 2, Step 4:

The licensee compared the projected drift values with the values used in the corresponding uncertainty/setpoint calculations and updated the uncertainty/setpoint calculations to address the comparisons. In no case was the revision of a TS Setpoint or Allowable Value required. Also, no safety analysis was required to be revised.

The licensee instituted several measures by which the uncertainty/setpoint calculations would be revised:

- Instrumentation calibrated on a more frequent surveillance interval than outage based was exempt from estimating the changes to drift.

- Where margin is required in the calculation, the projected drift values can be used in place of Calibration Tolerance, Measurement and Test Equipment and drift to obtain the TLU.
- As-found calibration tolerances would not be revised unless the existing tolerances were no longer conservative with respect to the Allowable Value.

NRC Evaluation:

The NRC staff agrees with the licensee's evaluation based on the measures stated above and finds the licensee's evaluation conclusions acceptable. Accordingly, the NRC staff finds the licensee has adequately addressed GL 91-04, Enclosure 2, Step 4.

GL 91-04, Enclosure 2, Step 5:

Confirm that the projected instrument errors caused by drift are acceptable for control of plant parameters to affect a safe shutdown with the associated instrumentation.

Licensee Evaluation of GL 91-04, Enclosure 2, Step 5:

Per the HBRSEP UFSAR Section 7.4, the plant is designed for safe shutdown if for some reason the main control room becomes inaccessible. The licensee evaluated a large list of equipment and determined the projected instrument errors caused by drift are acceptable for control of plant parameters to affect a safe shutdown with the associated instrumentation.

The LAR identifies the remote shutdown system TS 3.3.5 functions and instruments considered for drift. A separate drift analysis was not performed for the remote shutdown instruments based upon the design of the remote shutdown instruments and equipment history. Not all remote shutdown functions have uncertainty calculations associated with them. In its RAI response dated January 8, 2018 (Reference 5), the licensee explained that HBRSEP does not have uncertainty calculations specifically for the purpose of remote shutdown functions. Some components credited for remote shutdown have uncertainty calculations prepared for other purposes, such as for post-accident monitoring. Where uncertainty is required for a remote shutdown function, the uncertainty may be utilized from other uncertainty calculations associated with these functions or from uncertainty calculations for other safety-related instrument loops that use the same make and model number components in similar installations.

NRC Staff Evaluation:

Based on the aforementioned RAI response, the licensee confirmed that the functions and instruments identified in the LAR are the only instrumentation required to achieve safe shutdown and have SRs whose frequencies are being proposed for change and are applicable to the evaluations of Step 5 of Enclosure 2 of GL 91-04.

Extended drift intervals have been adequately applied to the calculations mentioned above; therefore, extended drift intervals have been applied to remote shutdown functions in all applications where drift is currently considered.

The licensee stated that the calculation that develops the setpoints used in the Remote Shutdown Procedures (1) obtains uncertainty values from the sources listed above and (2) the calculation has been reviewed to ensure extended drift intervals have been considered for all

setpoints used in Remote Shutdown procedures. The licensee identified calculations and associated functions that were updated to address extended drift and the calculations for components that are currently calibrated online and continue to be calculated online.

The licensee stated that no accuracy requirements exist for the functions listed for remote shutdown. When asked to explain this statement the licensee stated, "The statement that no accuracy requirements, for the functions listed for Remote Shutdown, exist pertains to Technical Specification Allowable Values and Analytical Limits. It is acknowledged that uncertainty must be applied to the setpoint values used in Remote Shutdown procedures, where applicable." The licensee further stated that the existing as-found tolerances will be used in the calibration procedures. The existing tolerances are based on a 22.5-month interval and, as such, it represents a conservative criterion because the drift for a 30-month interval could be larger.

The NRC staff agrees with the licensee's evaluation and finds the licensee's evaluation conclusions acceptable. Based on the foregoing, the NRC staff finds the licensee has adequately addressed GL 91-04, Enclosure 2, Step 5.

GL 91-04, Enclosure 2, Step 6:

Confirm that all conditions and assumptions of the setpoint and safety analyses have been checked and are appropriately reflected in the acceptance criteria of plant surveillance procedures for channel checks, channel functional tests and channel calibrations.

Licensee Evaluation for GL 91-04, Enclosure 2, Step 6:

The licensee determined that there are no setpoint or tolerance changes required as a result of calculation revisions. As-found and as-left values have been determined to be acceptable to ensure correct operation and operability of the instruments, with one exception mentioned below.

Seven maintenance procedures are impacted by this LAR. LP-022-1-PT, LP-022-2-PT, and LP--022-3-PT will be revised to institute a minimum calibration temperature. This is required to address low margin between the TLU and analytical value within the uncertainty/setpoint calculation. PIC-112, "F delta I Calibration" is being revised to state in the purpose that calibration of Power Range Indicator NI-303 is required to support operation on a 24-month fuel cycle. LP-001, LP-002, and LP-003 are being revised to require recording of as-found string data.

Licensee Evaluation of Impact to EST-047/WCAP-11889/SR 3.4.1.3:

As described in the subsection, "EST-047/WCAP-11889/SR 3.4.1.3," of the licensee's evaluation of Step 6, WCAP-11889, "RTD [Resistance Temperature Detector] Bypass Elimination Licensing Report for H. B. Robinson Unit 2" (Reference 23),[3] supported the installation of a then new reactor coolant temperature measurement system. WCAP-11889 also included the licensee's determination of the RCS flow uncertainty (i.e., 2.6%, with the new reactor coolant temperature measurement system). The discussion in the LAR under Step 6 provides the licensee's justification for retaining the RCS flow uncertainty of 2.6% while extending the fuel cycle from 18 to 24 months. The licensee, in part, states that neither the

[3] WCAP-11889 is a proprietary report. WCAP-11890 is the public version. The reference provides information applicable to both reports.

methodology nor the basis for the uncertainty values were provided to HBRSEP as part of the WCAP [WCAP-11889]; therefore, HBRSEP typically evaluates the impact to the WCAP by qualitative assessment. In its RAI response dated January 8, 2018 (Reference 5), the licensee explained how the impact of the change to a 24-month fuel cycle on the uncertainty presented by WCAP-11889 has been evaluated by qualitative assessment. SR 3.4.1.4 verifies the RCS total flow rate by precision heat balance, which must be completed within 24 hours of reaching Reactor Thermal Power ≥ 90%, after each refueling outage. The instrument required for the SR can either be calibrated online or during the preceding refueling outage. The instrumentation calibrated online will not have its calibration frequency changed and so is not impacted by the change to a 24-month fuel cycle. For instrumentation calibrated during the outage, since the SR occurs shortly after the startup after the outage, the SR is not impacted by the length of the fuel cycle.

The licensee stated Table 3.1-1 of WCAP-11889 lists the uncertainties of each of the inputs to the flow calorimetric. Those inputs include: Feedwater Temperature, Feedwater Pressure, Feedwater Flow, Steam Pressure, Hot Leg Temperature, Cold Leg Temperature, and Pressurizer Pressure. The calculated total uncertainty from all contributions was determined to be 2.3% flow as shown on Table 3.1-3 of the WCAP.

The licensee stated that the procedure used to perform SR 3.4.1.4 accounts for 2.6% instrument uncertainty above the SR stated value. This allowance is directly from WCAP-11889. This includes the uncertainty of the Cold Leg Elbow Tap, which is accounted for in the acceptance criteria for the precision heat balance calculation of RCS total flow.

The licensee stated that since the indications of Cold Leg Elbow Taps already take into account uncertainty for the operating cycle, the use of 2.6% flow from WCAP-11889 is an additional conservatism. The 2.6% flow uncertainty value is retained to preserve the values given in WCAP-11889; however, the value could be easily revised to remove the Cold Leg Elbow Tap uncertainty. This would result in an uncertainty value of 2.31% flow + 0.1% flow = 2.4% flow. However, making this change would result in moving away from the values given in the WCAP, which is not preferred.

The licensee stated that based on this evaluation, the uncertainty of the Cold Leg Elbow Taps is already accounted for in the values calculated in procedure used to perform SR 3.4.1.4, for use through the operating cycle. The 2.6% flow value given in WCAP-11889 is not affected as a result.

The licensee also indicated the drift calculation of the TLUs for the indication and trip functions provided by the RCS flow instrumentation loops has been updated to consider a 30-month calibration interval.

NRC Evaluation:

The NRC staff agrees with the licensee's evaluation and use of WCAP-11889, and finds the licensee's evaluation conclusions acceptable. Accordingly, the NRC staff finds the licensee has adequately addressed GL 91-04, Enclosure 2, Step 6.

<u>GL 91-04, Enclosure 2, Step 7:</u>

Provide a summary description of the program for monitoring and assessing the effects of increased calibration surveillance intervals on instrument drift and its effect on safety.

Licensee Evaluation for GL 91-04, Enclosure 2, Step 7:

The licensee states that instruments with TS calibration surveillance frequencies extended to 24 months will be monitored and trended in accordance with station procedures. As-found and as-left calibration data will be recorded for each 24-month calibration activity.

All out of tolerance conditions exceeding notification limits require engineering evaluation and trending per the Duke Energy calibration procedures and are entered in the corrective action program. The out of tolerance notification limits are conservative compared to the 30-month limits documented in the associated instrument setpoint and uncertainty calculation.

This will identify occurrences of instruments whose performance is not as assumed in the drift or setpoint analysis and instruments found outside of their allowable value. When the as-found conditions are outside the allowable value, an evaluation will be performed in accordance with the station corrective action program to evaluate the effect on plant safety.

This evaluation will be conducted to ensure the assumptions in the setpoint calculations continue to be valid. If this evaluation indicates that instrument performance is not consistent with assumptions, corrective actions will be taken in accordance with station corrective action requirements.

NRC Evaluation:

The NRC staff agrees with the assessment of the associated corrective action programs and finds the licensee's evaluation conclusions acceptable because the out of calibration issues will be evaluated and appropriate corrective actions will be taken per plant procedures. Accordingly, the NRC staff finds the licensee has adequately addressed GL 91-04, Enclosure 2, Step 7.

3.2.2 Summary of Detailed Drift Evaluation Methods

The licensee provided the drift evaluation methods in LAR Attachment 7. The drift evaluation method uses the as-found and as-left instrument calibration data to confirm the applicable requirements of GL 91-04. EPRI TR-103335 provides the guidelines for instrument calibration extension/reduction programs and has been used by many licensees for drift calibration extension (e.g., 18 to 24-month fuel cycle interval changes for River Bend Station, Unit 1; Oconee Nuclear Station, Units 1, 2, and 3). The NRC staff reviewed Revision 0 of this report and documented the status of that review in a letter to EPRI dated December 1, 1997. The NRC staff found that the TR offered generally acceptable guidance for meeting GL 91-04 calibration interval extension programs, except in areas mentioned in the December 1, 1997, review status letter. The NRC staff did not endorse or accept the TR for use by NRC staff or licensees. In a July 10, 2013, letter to EPRI (Reference 24) the NRC staff noted and described an error in Revision 1 of EPRI TR-103335. Revision 2 of EPRI TR-103335 was issued in January 2014 and a new report number was assigned to it (Report No. 3002002556) (Reference 25).[4] Revision 2 incorporates experience gained since 1994 and also addresses key regulatory issues that have surfaced since the previous revision was issued. Furthermore,

[4] For convenience and clarity, EPRI TR-103335, Revision 2 will be used instead of EPRI 3002002556 throughout the remainder of the SE.

this document builds on the knowledge gained from related EPRI studies pertaining to the nature of instrument drift.

The licensee evaluation is based on the guidance of EPRI TR-103335, Revision 1 per the current plant engineering guidance. In addition the guidance of EPRI TR-103335, Revision 2 has been used because it includes the regulatory issues that have surfaced since EPRI TR-103335, Revision 1. The loop and/or component drift data is characterized using probability analysis to understand the expected behavior of the loop and/or the components. It is confirmed that the data is normally distributed. The data is also checked for drift bias. Normally the mean of the data is zero or a very small number. Any significant value of mean is addressed as drift bias. The data analysis provides the basis for drift to be used for extending to 30 months (24 months + 25% allowance) as compared to the current drift based on 22.5 months (18 months + 25% allowance). Drift extension is based on the guidance of Section 9 of EPRI TR-103335, and is assumed to be moderate. Generally, the drift extension is based on the square root of the ratio of the extended time (30 months) and the current duration (22.5 months). If the test data analysis indicates time dependency by any of the tests (e.g., R Square Test or P Value Test) then the data should be considered as strongly time dependent and drift extension will be linear with time extension.

Licensee Evaluation:

The licensee stated in LAR Attachment 7, Section 4.3.2.6, that the methodology used is less suitable for evaluating the drift of a single instrument loop and/or component due to statistical analysis penalties that occur with smaller sample sizes.

With regard to ongoing instrument loop/component calibration as-found/as-left evaluation data, the licensee has stated the following in LAR Attachment 7, Section 5.11, regarding the drift evaluation methods:

> Robinson Nuclear has in place a continuing calibration surveillance procedure review program which verifies that loop/component As-Found calibration values do not exceed acceptable limits as defined in applicable Instrument Uncertainty Calculations, except on rare occasions.
>
> Once the 24-month Tech Spec Surveillance Requirement intervals have been approved and implemented, this calibration surveillance procedure review program will continue to verify that future loop/component As-Found calibration values do not exceed the Acceptable Limits determined in the Drift Evaluations and associated Instrument Uncertainty Calculations as revised to reflect a 30 month calibration frequency, except on rare occasions.

NRC Staff Evaluation:

In order to review the drift evaluation method the NRC staff requested the licensee to make available the calculations for audit by NRC staff. The NRC staff audited three sample calculations and found the calculations are consistent with the EPRI TR-103335, Revision 1 as updated by EPRI TR-103335, Revision 2, and are therefore acceptable. The audit is documented in an audit summary report (Reference 26).

3.2.3 Representative Instrument Calculation Evaluation

By letter dated April 3, 2017, the licensee submitted Calculation Number RNP-I/INST-1070, Revision 11 (Reference 2) as a representative instrument calculation that was revised to incorporate the changes from 18 month refuel cycle to 24-month refuel cycle. This calculation addresses Steam Generator Narrow Range Level Loop Uncertainty and Scaling Calculation. The calculation methodology is based on the licensee's procedure for Engineering Instrument Setpoints document EGR-NGGC-0153, Revision 12. The methodology follows ANSI/ISA-67.04.01-2000, Setpoints for Nuclear Safety-Related Instrumentation. The NRC staff reviewed the calculation and the methodologies and found that the calculation assumptions and methodology meets the intent of RG 1.105, Revision 3 (Reference 8) and RIS 2006-17 (Reference 9).

There were no changes to the calculated setpoints even though many small changes were made to several sections of the calculation. This calculation computes the loop uncertainties associated with the indication, recording, and trip functions provided by the steam generator narrow range level instrument loops. The instruments in this calculation are required to support normal functions, accident mitigation function, post-accident monitoring functions, and post-seismic functions. The calculation also provided input to the Emergency Response Facility Information System and Anticipated Transient without Scram Mitigation System Actuation Circuitry. Uncertainties were calculated for normal, accident, and seismic conditions.

The calculation describes the basis for assumptions, it includes all types of errors, such as instrument errors, process measurement errors, environmental errors including temperature and radiation, seismic errors, insulation resistance errors, power supply errors, measurement and test equipment errors including reading errors where applicable. The calculation also includes as-left and as-found tolerances.

The NRC staff finds the calculation includes total loop uncertainty, as-left tolerance, as-found tolerance, and margins for various functions. The margins are adequate. The NRC staff reviewed the setpoint methodology used by the calculation (licensee procedure for Engineering Instrument Setpoints document EGR-NGGC-0153, Revision 12) as part of an audit and confirmed it supported statements in the LAR (Reference 26). Based on the foregoing, the NRC staff finds the representative calculation and its calculation methodology acceptable. The NRC staff agrees that this representative approach is adequate for incorporating changes from 18 months to 24 months for other instrumentation.

3.2.4 Evaluation of Specific Surveillance Requirements and Associated Calibration Related Historical Records

The NRC staff finding on the proposed interval extensions for the calibrated related SRs is based on 1) consistency with the guidance provided in the GL 91-04, 2) historical plant maintenance and surveillance data supporting the conclusion, and 3) that the assumptions in the plant licensing-basis would not be invalidated as a result of this revision. The NRC staff evaluations in Sections 3.2.1 to 3.2.3 of this SE addressed these three findings generally. The NRC staff evaluation of the licensee review historical plant surveillance data for specific calibration related SRs is presented in this section of the SE. Accordingly, the conclusions for the specific SRs in this section of the SE is focused on the historical data finding, with the understanding that the general findings have previously been documented.

Attachment 6 to the LAR provides a review of historical records to support 24 month fuel cycle per the guidance of GL 91-04, Enclosure 2, Action 1. The purpose of this evaluation is to justify extension to 24 month fuel cycle. Per the guidance of GL 91-04 as-found and as-left data has been used by the licensee in support of this evaluation. The data review is limited to SRs associated with refueling outages and surveillances conducted every 18 months.

The licensee gathered the historical data for the last 10 years from the plant Records Management System (RMS). This data includes calibrations performed in 2005 or Refueling Outages 23 through 28 or six refueling outages. In addition, some data may be used from Refueling Outage 29.

The NRC staff agrees with the licensee's use of 10 years of data for its evaluation of historical data as this is comparable with previously approved 24-month SR extensions.

The following staff review evaluates the licensee explanation for the various technical specification changes.

Generic Evaluation of RTDs and Thermocouples

The licensee provided a generic evaluation of RTDs and thermocouples for the following SRs.

TS 3.3.1 Reactor Protection System (RPS) Instrumentation

SR 3.3.1.12 Perform CHANNEL CALIBRATION

Table 3.3.1-1 Function 5: Overtemperature ΔT

Table 3.3.1-1 Function 6: Overpower ΔT

TS 3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

SR 3.3.2.7 Perform CHANNEL CALIBRATION

Table 3.3.2-1 Function 1.e: Safety Injection - Steam Line High Differential Pressure Between Steam Header and Steam Lines

Table 3.3.2-1 Function 4.d: Steam Line Isolation - High Steam Flow in Two Steam Lines - Coincident with T_{avg} - Low

Table 3.3.2-1 Function 6.b: ESFAS Interlocks - T_{avg} - Low

TS 3.3.3 Post Accident Monitoring (PAM) Instrumentation

SR 3.3.3.2 Perform CHANNEL CALIBRATION

Table 3.3.3-1 Function 4: RCS Cold Leg Temperature

Table 3.3.3-1 Function 15: Core Exit Temperature – Quadrant 1

Table 3.3.3-1 Function 16: Core Exit Temperature – Quadrant 2

Table 3.3.3-1 Function 17: Core Exit Temperature – Quadrant 3

Table 3.3.3-1 Function 18: Core Exit Temperature – Quadrant 4

The RTDs associated with these SRs provide temperature compensation for the termination of thermocouples inside the Reference Junction Boxes, located in the Containment Vessel. The Core Exit Temperature is measured by thermocouples.

TS 3.3.4 Remote Shutdown System

SR 3.3.4.3 Perform CHANNEL CALIBRATION for each required instrumentation channel

Table B 3.3.4-1 Function 3.a: Decay Heat Removal via Steam Generators (SGs) - RCS Hot Leg Temperature

Table B 3.3.4-1 Function 3.b: Decay Heat Removal via Steam Generators (SGs) - RCS Cold Leg Temperature

The licensee reviewed information from the previous five performances of EST-052 "Operational Alignment of Process Temperature Instrumentation." Based on the reviewed data, one adjustment was required in 2007 to the low-level amplifier for RCS Loop #3, Hot Leg RTD #2. No other adjustments have been required since that time. The data from 2005 could not be obtained in RMS; however, as a conservative measure, data from the 2002 and 2004 performances were also reviewed. No adjustments were required during those performances.

Based on this review, the NRC staff finds the extension of the listed functions of SR 3.3.1.12, SR 3.3.2.7, SR 3.3.3.2, and SR 3.3.4.3 to accommodate a 24-month fuel cycle to be acceptable. The remainder of the instrument loops, which these devices are a part of, are evaluated in the applicable SR evaluations below.

TS 3.1.7 Rod Position Indication

SR 3.1.7.1 Perform CHANNEL CALIBRATION of the ARPI System

No as-found data was found in the records for ARPI. The licensee stated that this function does not require the same historical surveillance review as the typical as-found as-left evaluation because SR 3.1.4.1, "Verify individual rod positions within alignment limit," verifies the individual rod positions within alignment limits every 12 hours. The licensee further states that this more frequent surveillance will identify the rod positions being outside the TS limits.

Based on the rationale provided by the licensee, the NRC staff finds the extension of SR 3.1.7.1 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.1 Reactor Protection System (RPS) Instrumentation

SR 3.3.1.10 Perform CHANNEL CALIBRATION

Table 3.3.1-1 Function 7.a: Pressurizer Pressure – Low:

Three pressure transmitters and associated rack equipment provide this trip function to the RPS.

Table 3.3.1-1 Function 7.b: Pressurizer Pressure – High:

Three pressure transmitters and associated rack equipment provide this trip function to the RPS.

TS 3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

SR 3.3.2.7 Perform CHANNEL CALIBRATION

Table 3.3.2-1 Function 1.d: Pressurizer Pressure – Low:

Three pressure transmitters and associated rack equipment provide this actuation function to the ESFAS.

Table 3.3.2-1 Function 6.a: Pressurizer Pressure – Low:

Three pressure transmitters and associated rack equipment provide this interlock function to the ESFAS.

For the above SRs, the licensee identified one instance where a pressure transmitter exceeded the acceptance criteria in a non-conservative direction. No issues were found in the rack components. Based on the single exceedance, the licensee determined that changing the calibration interval for the above components is acceptable. The NRC staff agrees with this licensee evaluation. Therefore, the NRC staff finds the extension of the listed functions of SR 3.3.1.10 and SR 3.3.2.7 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.1 Reactor Protection System (RPS) Instrumentation

SR 3.3.1.10 Perform CHANNEL CALIBRATION

Table 3.3.1-1 Function 8: Pressurizer Pressure – High:

Three pressure transmitters and associated rack equipment provide this trip function to the RPS.

In 2010, one of the associated rack equipment, comparator LC-459A, was found out-of-tolerance but within the calculated allowed tolerance in the setpoint calculation. Hence there were no unacceptable failures. Therefore, the NRC staff finds the extension of the listed function of SR 3.3.1.10 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.1 Reactor Protection System (RPS) Instrumentation

SR 3.3.1.10 Perform CHANNEL CALIBRATION

Table 3.3.1-1 Function 9a: Reactor Coolant Flow – Low – Single Loop:

Table 3.3.1-1 Function 9b: Reactor Coolant Flow – Low – Two Loops:

Nine differential pressure transmitters and associated rack equipment provide these trip functions to the RPS. There are three transmitters per RCS Loop.

In 2007, differential pressure transmitter FT-436 was found out-of-tolerance at the lowest calibration point but was within the calculated tolerance above and below the setpoint. It was determined to be functional for performing its safety function.

In 2010, differential pressure transmitter FT-416 was found out-of-tolerance at all the upper three calibration points but was within the calculated tolerance above and below the setpoint. It was determined to be functional for performing its safety function.

In 2010, differential pressure transmitter FT-415 was found to be out-of-tolerance (high) at all five calibration points. This transmitter was replaced. In 2012 the replaced transmitter was again found out-of-tolerance (high) at three highest calibration points. This out-of-tolerance exceeded TS allowable limits. Two most recent calibrations had no out-of-tolerance readings. The licensee states that this is the first unacceptable out-of-tolerance for the replaced transmitter and could be attributed to the settling in of the new transmitter to the new environment. The other out-of-tolerances were on different pieces of equipment. There were a total of 72 calibration records for the same transmitter model number for this function with a total of two issues with FT-415. The transmitter was replaced after the first issue and the second issue involves a different transmitter. Since the events occurred on unrelated transmitters and the last two calibrations were found to be within tolerance the licensee stated extension of calibration to 24 months is acceptable.

Based on one failure of FT-415 out of a total of 72 calibrations the NRC staff determined the calibration extension to 24 months will not result in more than a minimal increase in risk to safety. Therefore, the NRC staff finds the extension of the listed functions of SR 3.3.1.10 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.1 Reactor Protection System (RPS) Instrumentation

SR 3.3.1.10 Perform CHANNEL CALIBRATION

Table 3.3.1-1 Function 11: Undervoltage RCPs:

Three undervoltage relays are associated with this trip function to the RPS. One is located on each applicable 4KV bus (Bus 1, 2, 4).

TS 3.3.8 Auxiliary Feedwater (AFW) System Instrumentation

SR 3.3.8.4 Perform CHANNEL CALIBRATION

Table 3.3.8-1 Function 4: Undervoltage Reactor Coolant Pump:

Four undervoltage relays are associated with this function. Two are located on each applicable 4KV bus. This function is a two-out-of-two logic on both 4KV bus. All four relays must actuate to perform this function.

Pertaining to the above two functions, no data was recorded for two relays during a 2012 relay replacement. All other recoded data had no exceedances. Based on the acceptability of the overall data, the NRC staff finds the extension of the listed functions of SR 3.3.1.10 and SR 3.3.8.4 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.1 Reactor Protection System (RPS) Instrumentation

SR 3.3.1.10 Perform CHANNEL CALIBRATION

Table 3.3.1-1 Function 12: Underfrequency RCP:

Three underfrequency relays are associated with this trip function to the RPS. One is located in each of the applicable 4KV bus (Bus 1, 2, 4).

After failure of relay 811/1 in 2007 it was replaced. The relay was found within as-found tolerance limits but the relay could not be adjusted within as left allowance. Therefore, the relay was replaced.

In 2008 relay 811/1 was found out of the relay setting tolerance but was within the allowable value based on special relay calibration procedure which has very tight tolerances. The relay was functional but had to be recalibrated to be within the tight calibration tolerances. A similar event happened in 2013 which was within allowable value but out of the special relay setting tolerances.

Relay 811/2 had a similar event in 2008. The relay was found within allowable value but out of the special relay setting tolerances.

In its RAI responses dated January 8, 2018 (Reference 5), the licensee explained how the licensee Procedure PIC-806 provides the instructions for performing the calibration check of the RCP underfrequency relays. In the event that the as found values are outside the allowable tolerance range, the relay technician is required to notify the appropriate management and plant procedures require appropriate reviews of the out of tolerance to take place. The licensee explained that the relay calibration tolerances are very low.

Based on the above review all out of tolerances were within the allowable value and did not affect the relay function adversely. Therefore the only failure of the relay 811/1 happened in 2007 when the relay was replaced. Based on this one failure, the NRC staff finds the extension of the listed function of SR 3.3.1.10 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.1 Reactor Protection System (RPS) Instrumentation

SR 3.3.1.10 Perform CHANNEL CALIBRATION

Table 3.3.1-1 Function 13: Steam Generator (SG) Water Level – Low Low:

Nine differential pressure transmitters and associated rack equipment provide this trip function to the RPS. There are three transmitters per SG.

TS 3.3.8 Auxiliary Feedwater (AFW) System Instrumentation

SR 3.3.8.4 Perform CHANNEL CALIBRATION

Table 3.3.8-1 Function 1: SG Water Level – Low Low:

Nine differential pressure transmitters and associated rack equipment provide this actuation signal to the Auxiliary Feedwater System. There are three transmitters per SG. Two-out-of-three logic is required to actuate the system.

There were no issues identified with both of these functions. Therefore, the NRC staff finds the extension of the listed functions of SR 3.3.1.10 and SR 3.3.8.4 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.1 Reactor Protection System (RPS) Instrumentation

SR 3.3.1.10 Perform CHANNEL CALIBRATION

Table 3.3.1-1 Function 15.a: Turbine Trip – Low EH [electro-hydraulic] Fluid Oil Pressure (also referred to as Low Auto Stop Oil Pressure):

Three pressure switches provide this trip function to the RPS.

Three occurrences of a Turbine Auto Stop Trip Pressure Switch exceeding the Allowable Value were reviewed. All three were discovered during different outages over a seven year period. Each occurrence was associated with a different switch; therefore, there was no consecutive occurrences that would indicate a repetitive problem.

Based on the number of problems this would be considered to exceed "rare occasions". The licensee committed to replace the pressure switches upon implementation of the license amendment, as documented as Commitment 1 in Attachment 5 of the LAR. In addition, the licensee will evaluate instrument performance (as-found, as-left values) at the end of each of the three refuel outages after the replacement to confirm that the instruments are working properly consistent with the guidance of GL 91-04.

The NRC staff notes that there were not repetitive or concurrent failures of individual switches. Further, the licensee made a commitment to replace the switches in Attachment 5 to the LAR. The NRC staff agrees with this commitment. Since the NRC approval of the extension of this function of the SR is based in part on the replacement of the pressure switches, the NRC staff has included this commitment as an implementation item. Accordingly the NRC staff finds the

extension of the listed function of SR 3.3.1.10 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.1 Reactor Protection System (RPS) Instrumentation

SR 3.3.1.10 Perform CHANNEL CALIBRATION

SR 3.3.1.13 Perform COT

Table 3.3.1-1 Function 17.e: Reactor Protection System Interlocks – Turbine Impulse Pressure, P-7 Input

Two pressure transmitters and associated rack components provide this interlock function to the P-7 logic.

The two pressure transmitters associated with these functions are evaluated in the SR 3.3.2.7, Functions 1.f, and 4.d evaluation in this section of the SE. The licensee identified no issues with those transmitters or the rack components.

Based on this review, the NRC staff finds the extension of the listed functions of SR 3.3.1.10 and SR 3.3.1.13 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.1 Reactor Protection System (RPS) Instrumentation

SR 3.3.1.11 Perform CHANNEL CALIBRATION

Table 3.3.1-1 Function 2.a: Power Range Neutron Flux – High

Four channels of power range, neutron flux monitors and internal components of each monitor provide this trip function to the RPS System.

Table 3.3.1-1 Function 2.b: Power Range Neutron Flux – Low

Four channels of power range, neutron flux monitors and internal components of each monitor provide this trip function to the RPS System.

SR 3.3.1.11 Perform CHANNEL CALIBRATION

SR 3.3.1.13 Perform COT

Table 3.3.1-1 Function 17.c: Reactor Protection System Interlocks – Power Range Neutron Flux, P-8

Four channels of power range, neutron flux monitors and internal components of each monitor provide this interlock function to the RPS System.

Table 3.3.1-1 Function 17.d: Reactor Protection System Interlocks – Power Range Neutron Flux, P-10

Four channels of power range, neutron flux monitors and internal components of each monitor provide this interlock function to the RPS System.

Additionally, low and high flux signals are developed and used in the overtemperature and overpower reactor trips (Table 3.3.1-1, Functions 5 and 6). Additional, internal components of each monitor provide this signal to those functions.

One of the components of each monitor, NM310, is adjusted every 24 hours for SR 3.3.1.2; therefore, it is not calibrated to a specific tolerance during channel calibrations; therefore, it is part of this evaluation.

Some of the readings were out of calibration tolerance but none of the out-of-tolerance readings exceeded the calculated as-found conditions and therefore, none of them exceeded the allowable tolerance.

In 2008, an internal monitor component, NM306, of a power range, neutron flux monitor, N-41 was found out-of-tolerance. The licensee technical review of calibration data, included in the surveillance, determined this issue was within the allowable value given in TS and uncertainty calculations. Therefore, the licensee considered this out-of-tolerance not to exceed acceptable limits.

In 2006, an internal monitor component, NC306, reset of a power range, neutron flux monitor, N-43, was found out-of-tolerance high. The licensee determined this does not affect the trip function; therefore, the licensee considered this out-of-tolerance not to exceed acceptable limits.

In 2009, an internal monitor component, NC305, of a power range, neutron flux monitor, N-43, was found out-of-tolerance low on the action and reset function. The licensee determined that the reset function has no impact on the TS function. The trip function was out-of-tolerance in a conservative manner; therefore, the licensee considered this out-of-tolerance not to exceed acceptable limits.

In 2013, an internal monitor component, NC306 of a power range, neutron flux monitor, N-44, was found out-of-tolerance low. This trip function was out-of-tolerance in a conservative manner; therefore, the licensee considered this out-of-tolerance not to exceed acceptable limits.

In summary, the licensee historical surveillance identified no issues that exceeded acceptable limits. The NRC staff agrees with the licensee evaluation.

Based on this review, the NRC staff finds the extension of the listed functions of SR 3.3.1.11 and SR 3.3.1.13 to accommodate a 24-month fuel cycle to be acceptable.

<u>TS 3.3.1 Reactor Protection System (RPS) Instrumentation</u>

SR 3.3.1.11 Perform CHANNEL CALIBRATION

Table 3.3.1-1 Function 4: Source Range Neutron Flux

Two channels of source range, neutron flux monitors provide this reactor trip signal to the RPS. Rack components and comparator module in each monitor actuate the trip output function.

TS 3.9.2 Nuclear Instrumentation

SR 3.9.2.2 Perform CHANNEL CALIBRATION

Two channels of source range, neutron flux monitors provide this indication function. A count rate monitor provides the indication function in each monitor, along with two indications.

In 2015, the count rate monitor, NI-101, and an indication, NI-31B, associated with a neutron flux monitor, NI-31, was found out-of-tolerance low. The licensee determined that this would have resulted in non-conservative readings of source range flux. This was a result of a rack component, NM-104, having failed. The licensee replaced the component. The condition would have also resulted in the signal to the comparator module NC-101 being out-of-tolerance.

In 2007, an indication, NI-32B, associated with a neutron flux monitor, NI-32, was found out-of-tolerance high. This would result in a conservative reading for source range flux and does not exceed acceptable limits.

As there was one identified occurrence of exceeding acceptable limits; the licensee determined that the occurrence does not exceed a rare occasion.

Based on this review, the NRC staff finds the extension of the listed functions of SR 3.3.1.11 and SR 3.9.2.2 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.1 Reactor Protection System (RPS) Instrumentation

SR 3.3.1.11 Perform CHANNEL CALIBRATION

SR 3.3.1.13 Perform COT

Table 3.3.1-1 Function 17.a: Intermediate Range Neutron Flux, P-6

Two channels of intermediate range, neutron flux monitors and internal components of each monitor provide this interlock function to the RPS System.

SR 3.3.1.11 Perform CHANNEL CALIBRATION

Table 3.3.1-1 Function 3: Intermediate Range Neutron Flux

Two channels of intermediate range, neutron flux monitors and internal components of each monitor provide this trip function to the RPS System.

The licensee identified no issues that required additional evaluation.

Based on this review, the NRC staff finds the extension of the listed functions of SR 3.3.1.11 and SR 3.3.1.13 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.1 Reactor Protection System (RPS) Instrumentation

SR 3.3.1.12 Perform CHANNEL CALIBRATION

Table 3.3.1-1 Function 5: Overtemperature ΔT

Table 3.3.1-1 Function 6: Overpower ΔT

Twelve low level amplifiers/RTDs and associated rack equipment provide these trip functions to the RPS. Four low level amplifiers are in each of three protection channels, corresponding to the three RCS loops. Inputs are also provided to the instrument loops from other protection channels. Pressurizer pressure transmitters provide an input signal to the corresponding temperature protection loop and upper and lower flux signals are provided to each temperature protection channel from the Nuclear Instrument System.

Review of the components that provide the pressurizer pressure and nuclear instrument signals to the temperature protection channels are documented in other portions of this evaluation. The evaluation of the pressurizer pressure transmitters are included in the evaluation of SR 3.3.1.10 Function 7.a. The upper and lower flux input signals are evaluated in the SR 3.3.1.11 Functions 2.a, 2.b, 17.c and 17.d.

The RTDs that provide input to the low level amplifiers have been evaluated generically in the beginning of this section and found acceptable.

The licensee stated that the instrument loops associated with this function have a COT performed every 92 days. The instrument loop allowable values are verified during each COT.

The licensee found satisfactory the verification of low level amplifiers and time constants.

In 2005 and 2007, the licensee found an associated rack equipment, TM-432L, out-of-tolerance low. In 2008, the licensee found an associated rack equipment, TM-432L was found out-of-tolerance high for a total of three out-of-tolerance three times, which exceeded the allowable limits. The licensee replaced it with a newer model in 2010. Since the replacement no out-of-tolerance condition has been noted and the component is working satisfactorily.

Based on the above evaluation, the NRC staff finds the extension of the listed functions of SR 3.3.1.12 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.1 Reactor Protection System (RPS) Instrumentation

SR 3.3.1.13 Perform COT [Channel Operational Test]

Table 3.3.1-1 Function 17.b: Low Power Reactor Trips Block, P-7

This interlock is derived in the relay logic cabinets. The signals that provide an input to this function are evaluated in the SR 3.3.1.11 Functions 17.d and Item 17.e. No additional evaluation is required for this function.

Based on this review, the NRC staff finds the extension of the listed function of SR 3.3.1.13 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

SR 3.3.2.7 Perform CHANNEL CALIBRATION

Table 3.3.2-1 Function 1.c: Safety Injection – Containment Pressure – High:

Three pressure transmitters and associated rack equipment provide this actuation function to the ESFAS.

Table 3.3.2-1 Function 2.c: Containment Spray – Containment Pressure High High:

Six pressure transmitters and associated rack equipment provide this actuation function to the ESFAS.

Table 3.3.2-1 Function 3.b.3: Containment Isolation – Phase B Isolation -Containment Pressure High High:

Six pressure transmitters and associated rack equipment provide this actuation function to the ESFAS.

Table 3.3.2-1 Function 4.c: Steam Line Isolation – Containment Pressure High High:

Six pressure transmitters and associated rack equipment provide this actuation function to the ESFAS.

The licensee review of the calibration data did not identify any failures that required review. Based on this review, the licensee found the surveillance testing of these functions to be acceptable to be extended to accommodate a 24-month fuel cycle.

Since there were no issues identified with the above functions, the NRC staff finds the extension of the listed functions of SR 3.3.2.7 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

SR 3.3.2.7 Perform CHANNEL CALIBRATION

Table 3.3.2-1 Function 1.e: Safety Injection – Steam Line High Differential Pressure Between Steam Header and Steam Lines:

This function provides an actuation signal to the ESFAS to initiate a SI. The function is a two-out-of-three logic on any Steam Line. The function consist of the pressure transmitters and associated rack equipment.

The licensee reviewed all components' calibrations and no issues were identified. Based on this review of surveillance testing, the NRC staff finds the extension of the listed function of SR 3.3.2.7 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

SR 3.3.2.7 Perform CHANNEL CALIBRATION

Table 3.3.2-1 Function 1.f: Safety Injection – High Steam Flow in Two Steam Lines Coincident with T_{avg} – Low

Table 3.3.2-1 Function 4.d: Steam Line Isolation – High Steam Flow in Two Steam Lines Coincident with T_{avg} – Low

Table 3.3.2-1 Function 6.b: ESFAS Interlocks – T_{avg} – Low

The RTD low level amplifiers associated with these functions are evaluated in the SR 3.3.1.12, Functions 5 and 6 evaluation in this section of the SE. The licensee identified no issues with the low level amplifiers in its historical surveillance review.

In 2008 and in 2013, a summator, PM-447B, was found out-of-tolerance low. This summator provides the Channel IV, First Stage Pressure signal for comparison with Channel IV Steam Flow signals. It also exceeded the as-found values of RNP-I/INST-1045. This component being out-of-tolerance low would represent lower power levels to compare to steam flow. The licensee determined that the out-of-tolerance low would be a conservative condition.

In 2009, a summator, PM-494C, was found out-of-tolerance low. This summator provides the Channel III, SG "C" Steam Flow signal for comparison with Channel III First Stage Pressure signal. It exceeded the as-found values of RNP-I/INST-1045 at the highest point only; therefore, the licensee considered it to exceed acceptable limits.

In 2005, a summator, TM-412N was found out-of-tolerance high. This summator provides a signal representing the average of Loop #1, Hot Leg RTDs. No uncertainty calculation existed at the time of this out-of-tolerance to determine the as-found value. In 2014, calculation RNP-I/INST-1154 was issued. Based on the as-found values calculated in RNP--I/INST-1154, the summator module did not exceed the calculated as-found.

Only one transmitter in 2009 was classified in an out-of-tolerance condition that exceeded acceptable limits. The licensee determined that the single out-of-tolerance condition does not exceed a rare occasion.

Only one rack component in 2005 was identified to exceed acceptable limits. This was the only occurrence and the licensee determined it does not exceed rare occasion.

The two failures are in different components at different times. There are no two consecutive failures of the same component. Based on this review, the NRC staff finds the extension of the listed functions of SR 3.3.2.7 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

SR 3.3.2.7 Perform CHANNEL CALIBRATION

Table 3.3.2-1 Function 1.g: Safety Injection – High Steam Flow in Two Steam Lines Coincident with Steam Line Pressure – Low

Table 3.3.2-1 Function 4.e: Steam Line Isolation – High Steam Flow in Two Steam Lines Coincident with Steam Line Pressure – Low

Many of the components associated with these functions are evaluated in the SR 3.3.2.7, Functions 1.e, 1.f, and 4.d evaluation in this section of the SE.

No issues were identified for the remainder of components evaluated.

Based on this review, the NRC staff finds the extension of the listed functions of SR 3.3.2.7 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.3 Post Accident Monitoring (PAM) Instrumentation

SR 3.3.3.2 Perform CHANNEL CALIBRATION

Table 3.3.3-1 Function 1: Power Range Neutron Flux

Table 3.3.3-1 Function 2: Source Range Neutron Flux

Two channels of gamma-metrics, neutron flux monitors provide this indication function along with other components.

TS 3.3.4 Remote Shutdown System

SR 3.3.4.3 Perform CHANNEL CALIBRATION for each required instrumentation channel

Table B 3.3.4-1 Function 1.a: Reactivity Control – Source Range Neutron Flux

Two channels of gamma-metrics, neutron flux monitors provide this indication function along with other components.

In 2006, a component, NI-51, was found out-of-tolerance low. The licensee technical review of calibration data, included in the surveillance record, determined the out-of-tolerance condition was conservative. Also, the out-of-tolerance error was small enough that it would not have affected the operator's ability to verify that the reactor is shutdown. Therefore, the licensee considered this out-of-tolerance not to exceed acceptable limits.

In 2012, the component, NI-51, was found out-of-tolerance. The licensee technical review of calibration data, included in the surveillance record, determined the out-of-tolerance condition would not have been discernable to the operators on a logarithmic scale. Therefore, the licensee considered this out-of-tolerance not to exceed acceptable limits.

Based on this review, the NRC staff finds the extension of the listed functions of SR 3.3.3.2 and SR 3.3.4.3 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.3 Post Accident Monitoring (PAM) Instrumentation

SR 3.3.3.2 Perform CHANNEL CALIBRATION

Table 3.3.3-1 Function 3: Reactor Coolant System (RCS) Hot Leg Temperature

This function is performed by three RTDs, associated rack equipment, and indications.

TS 3.3.4 Remote Shutdown System

SR 3.3.4.3 Perform CHANNEL CALIBRATION for each required instrumentation channel

Table B 3.3.4-1 Function 3.a: Decay Heat Removal via Steam Generators (SGs) – RCS Hot Leg Temperature Wide Range Loop A

This function is performed by one RTD, associated rack equipment, and indications.

The generic evaluation of the RTDs at the beginning of this Section of the SE is applicable to the RTDs for these functions.

An indicator, TI-413B, was found out of tolerance in 2009 and again in 2010. The indicator was replaced in 2009, following issues identified in the previous calibration. The second out-of-tolerance condition of the indicator in 2010 was the first following replacement. As three calibrations have taken place since that time with no identified issues, the licensee determined that the out-of-tolerance condition of the indicator in 2010 can most likely be attributed to the settling of the indicator and that the replacement of the indicator fixed the problem.

Based on this review, the NRC staff finds the extension of the listed functions of SR 3.3.3.2 and SR 3.3.4.3 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.3 Post Accident Monitoring (PAM) Instrumentation

SR 3.3.3.2 Perform CHANNEL CALIBRATION

Table 3.3.3-1 Function 4: RCS Cold Leg Temperature

This function is performed by three RTDs, associated rack equipment, and indications.

TS 3.3.4 Remote Shutdown System

SR 3.3.4.3 Perform CHANNEL CALIBRATION for each required instrumentation channel

Table B 3.3.4-1 Function 3.b: Decay Heat Removal via Steam Generators (SGs) – RCS Cold Leg Temperature Wide Range Loop A

This function is performed by one RTD, associated rack equipment, and indications.

The generic evaluation of the RTDs at the beginning of this Section of the SE is applicable to the RTDs for these functions.

In 2006, associated rack equipment, repeater module TY-410, was found out-of-tolerance low; however, it was within the tolerance limits in calculation RNP-I/INST-1063. The component met acceptable limits.

Based on this review, the NRC staff finds the extension of the listed functions of SR 3.3.3.2 and SR 3.3.4.3 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.3 Post Accident Monitoring (PAM) Instrumentation

SR 3.3.3.2 Perform CHANNEL CALIBRATION

Table 3.3.3-1 Function 5: RCS Pressure (Wide Range)

Two pressure transmitters, associated rack equipment, and indications provide this function. Calculations RNP-I/INST-1065 and RNP-I/INST-1127 apply to this function.

The licensee identified no issues in its review of surveillance testing for this SR. Based on this review, the NRC staff finds the extension of the listed function of SR 3.3.3.2 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.3 Post Accident Monitoring (PAM) Instrumentation

SR 3.3.3.2 Perform CHANNEL CALIBRATION

Table 3.3.3-1 Function 6: Refueling Water Storage Tank Level

Two differential pressure transmitters and associated indications provide this function.

Although this is an 18-month SR, the transmitters are actually currently calibrated yearly. While the licensee is requesting a 24-month SR, the licensee stated that it plans to maintain the actual yearly calibration intervals. However, the licensee could change the actual calibration interval to be consistent with the SR at a later time. The licensee used the yearly data to determine if extension for a 24-month fuel cycle is acceptable.

In 2009, a differential pressure transmitter, LT-948, was found out-of-tolerance at the highest calibration point; however, compared to the calculation as-found values listed in RNP-I/INST-1023, the transmitter was within the acceptable limits. No other out-of-tolerances were identified.

The current calibration of these transmitters is performed every 12 months. The licensee described how it applied the guidance in GL 91-04 to approximately 12 month historical data versus the typical approximately 18 month historical data. The NRC staff audited the calibration data and found the data supports the licensee's statements that the surveillance history supports a 24-month fuel cycle. Based on this review, the NRC staff finds the extension of the listed function of SR 3.3.3.2 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.3 Post Accident Monitoring (PAM) Instrumentation

SR 3.3.3.2 Perform CHANNEL CALIBRATION

Table 3.3.3-1 Function 7: Containment Sump Water Level (Wide Range)

Two level transmitters and associated indication provide this function.

TS 3.4.15 RCS Leakage Detection Instrumentation

SR 3.4.15.3 Perform CHANNEL CALIBRATION of the required containment sump monitor

Two level transmitters and associated indication provide this function.

The licensee stated that level transmitters are not calibrated based on design of the components. In its RAI responses dated January 8, 2018 (Reference 5), the licensee explained that the level transmitter is a tubular sensor containing reed switches along the length of the stem and a permanent magnet that changes the position of the reed switches when level changes. The transmitters are functionally checked as part of the SR. The licensee found only one issue with a level transmitter, LT-801, during its review of surveillance testing.

Monthly surveillance testing is conducted based on SR 3.3.3.1 per plant procedure (OST-023). Since no transmitter calibration is performed (due to the design of the component) most problems will be discovered during monthly surveillance testing. Hence extending the surveillance test interval from 18 months to 24 months is acceptable.

In 2010, an associated indication, LI-801, was found out-of-tolerance during testing; however, the indicator was in tolerance during the five point calibration. Therefore, the indicator was still capable of providing indication of sump level. This issue was with the loop test function, not a calibration problem.

Based on this review, the NRC staff finds the extension of the listed functions of SR 3.3.3.2 and SR 3.4.15.3 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.3 Post Accident Monitoring (PAM) Instrumentation

SR 3.3.3.2 Perform CHANNEL CALIBRATION

Table 3.3.3-1 Function 8: Containment Pressure (Wide Range)

Two pressure transmitters and associated indications provide this function.

In 2007, one pressure transmitter, PT-957, was found out-of-tolerance; however, based on the as-found values calculated in RNP-I/INST-1057, the transmitter was within tolerance.

Based on this review, the NRC staff finds the extension of the listed function of SR 3.3.3.2 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.3 Post Accident Monitoring (PAM) Instrumentation

SR 3.3.3.2 Perform CHANNEL CALIBRATION

Table 3.3.3-1 Function 10: Containment Area Radiation (High Range)

Two radiation monitors provide this indication function.

The licensee identified no issues during its review of the surveillance testing records.

Based on this review, the NRC staff finds the extension of the listed function of SR 3.3.3.2 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.3 Post Accident Monitoring (PAM) Instrumentation

SR 3.3.3.2 Perform CHANNEL CALIBRATION

Table 3.3.3-1 Function 12: Pressurizer Level

Three differential pressure transmitters, associated rack equipment, and indications provide this function.

The level transmitters are evaluated in the SR 3.3.1.10, Function 8 evaluation in this section of the SE. No issues were identified for those components. Regarding the rack equipment and indications, the licensee found no issues that required additional review.

Based on this review, the NRC staff finds the extension of the listed function of SR 3.3.3.2 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.3 Post Accident Monitoring (PAM) Instrumentation

SR 3.3.3.2 Perform CHANNEL CALIBRATION

Table 3.3.3-1 Function 13: Steam Generator Water Level (Narrow Range)

Nine differential pressure transmitters, associated rack equipment, and indicators provide this function. There are three transmitters associated with each of three steam generators. The TS requires two per steam generator.

The pressure transmitters are evaluated in the SR 3.3.1.10, Function 13 evaluation in this section of the SE. No issues were identified for the transmitters. This review will be for the rack equipment and indications.

In 2012, an indication, LI-476, was found out-of-tolerance. The as-found tolerance also exceeded the calculated values of RNP-I/INST-1070. This exceeded acceptable limits.

No other issues were identified; therefore, the one issue with LI-476 did not exceed rare occasions.

Based on this review, the NRC staff finds the extension of the listed function of SR 3.3.3.2 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.3 Post Accident Monitoring (PAM) Instrumentation

SR 3.3.3.2 Perform CHANNEL CALIBRATION

Table 3.3.3-1 Function 14: Condensate Storage Tank Level

Two differential pressure transmitters and the associated indicators provide this function.

In 2009, an indication, LI-1454A, was found out-of-tolerance at one of the five calibration points; however, the as-found tolerance was within the calculated values of RNP-I/INST-1015. This does not represent equipment exceeding acceptable limits.

In December of 2012, the two differential pressure transmitters were found to have a deviation of greater than 5%. The licensee stated that the excessive drift was identified by more frequent surveillances. The licensee replaced these transmitters. In LAR Attachment 6, the licensee states that it was unable to obtain calibration data for the replaced transmitters. In its RAI responses dated January 8, 2018 (Reference 5), the licensee stated that it was able to obtain the calibration data on the transmitters and that four successful calibrations were conducted for each transmitter.

Based on frequent surveillance testing and subsequent successful testing of the replaced transmitters, the NRC staff finds the extension of the listed function of SR 3.3.3.2 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.3 Post Accident Monitoring (PAM) Instrumentation

SR 3.3.3.2 Perform CHANNEL CALIBRATION

Table 3.3.3-1 Function 15: Core Exit Temperature – Quadrant 1

Table 3.3.3-1 Function 16: Core Exit Temperature – Quadrant 2

Table 3.3.3-1 Function 17: Core Exit Temperature – Quadrant 3

Table 3.3.3-1 Function 18: Core Exit Temperature – Quadrant 4

This function is comprised of two independent trains. Each train consists of thermocouples located at various locations internal to the reactor, near the top of the fuel assemblies, three RTDs at the reference junction box, computer processor, and display.

The licensee identified no issues from the review of surveillance testing records for this function.

Based on this review, the NRC staff finds the extension of the listed functions of SR 3.3.3.2 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.3 Post Accident Monitoring (PAM) Instrumentation

SR 3.3.3.2 Perform CHANNEL CALIBRATION

Table 3.3.3-1 Function 19: Auxiliary Feedwater Flow

Six differential pressure transmitters, associated square root extractor modules, and indications provide this function.

The licensee identified that the pressure transmitters were out-of-tolerance four times yet within the calculation tolerance. In its RAI responses dated January 8, 2018 (Reference 5), the licensee explained that calibration procedure tolerance is +/- 0.5% while the calculation tolerance is +/- 1.23%. The licensee also presented the data where the calibration procedure tolerance was exceeded but not the calculation tolerance. In 2013, the differential pressure transmitter, FT-1426A, was found out-of-tolerance by -0.875%. In 2013, the differential pressure transmitter, FT-1426B, was found out-of-tolerance by -0.85%. In 2012, FT-1426C was found out-of-tolerance by +0.575% at the highest calibration point. In 2013, FT-1426C was found out-of-tolerance by -1.225%. However, each of the found out-of-tolerances is less than the calculated as-found tolerance of 1.23%, based on RNP-I/INST-1055. As all of the calibration points were within the calculated tolerances; the licensee determined that the found out-of-tolerances are not considered an issue for this evaluation.

Based on this review of the surveillance testing, the NRC staff finds the extension of the listed function of SR 3.3.3.2 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.3 Post Accident Monitoring (PAM) Instrumentation

SR 3.3.3.2 Perform CHANNEL CALIBRATION

Table 3.3.3-1 Function 20: Steam Generator Pressure

Nine pressure transmitters, associated rack equipment, and indications provide this indication function.

The pressure transmitters are evaluated in the SR 3.3.2.7, Function 1.e evaluation in this section of the SE.

In 2005, the indication, PI-474, was found out-of-tolerance. It also exceeded the calculated as-found values from RNP-I/INST-1043. The licensee considered the out-of-tolerance to exceed acceptable limits. No other issues were identified. Therefore, the licensee determined that the one out-of-tolerance did not exceed rare occasions.

Based on this review, the NRC staff finds the extension of the listed functions of SR 3.3.3.2 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.3 Post Accident Monitoring (PAM) Instrumentation

SR 3.3.3.2 Perform CHANNEL CALIBRATION

Table 3.3.3-1 Function 21: Containment Spray Additive Tank Level

Two differential pressure transmitters and indications provide this indication function.

The licensee identified no issues in the available work order records. The licensee identified that after 2009, the frequency of calibration was incorrectly changed to approximately 8 years. However, the data that was reviewed showed the components had no previous issues. In addition, the components were calibrated in 2016, for the first time in approximately 7 years and were found in tolerance.

Based on this review and because after 7 years the components were found in tolerance, the NRC staff finds the extension of the listed function of SR 3.3.3.2 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.4 Remote Shutdown System

SR 3.3.4.3 Perform CHANNEL CALIBRATION for each required instrumentation channel

Table B 3.3.4-1 Function 2.a: Reactor Coolant System (RCS) Pressure Control -Pressurizer Pressure.

One pressure transmitter and indications provide this indication function.

The licensee stated that the calibration data sheet for one of the indications, PI-607E-2, does not contain tolerances and that no calculation exist for this indicator. Therefore, the licensee used the calibration tolerances of the other indication, PI-607E-1, to determine acceptable limits.

In 2008, the indication, PI-607E-2, was found out-of-tolerance high at all points. The licensee considered this out-of-tolerance to exceed acceptable limits.

In 2013, the same indication, PI-607E-2 was found out-of-tolerance high at all points. The licensee considered this out-of-tolerance to exceed acceptable limits.

Thus, there were two issues identified for indicator PI-607E-2. The licensee stated that the indicator was still capable of indicating Pressurizer Pressure; however, in both cases the reading would have been elevated. In its RAI responses dated January 8, 2018 (Reference 5), the licensee stated that the two indicators, PI-607E-1 and PI-607E-2, are used for remote shutdown function and as such they do not perform any safety function and they are considered as augmented quality only. The two out of tolerance readings are not consecutive failures. Out of two indicators only one indicator is needed to support safe shutdown and there was always one indicator that was within tolerance limits. Out of a total of seven calibrations only two non-consecutive readings were found out of tolerance.

Based on this review, the NRC staff finds the extension of the listed non-safety function of SR 3.3.4.3 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.4 Remote Shutdown System

SR 3.3.4.3 Perform CHANNEL CALIBRATION for each required instrumentation channel

Table B 3.3.4-1 Function 3.d: Decay Heat Removal via Steam Generators (SGs) – SG Pressure

Three pressure indicator/controllers provide this indication function. The licensee performs calibration of these components along with other components applicable to operation of the Main Steam Relief Valves. The portion of the calibration that is applicable to this SR is calibration of the steam line pressure pointers

In 2005, the licensee surveillance record stated that all indicators were found unsatisfactory; however, the licensee review of the calibration data sheets confirmed that only one indicator, PIC-477, was found out-of-tolerance at one calibration point, in one direction only. The difference between the surveillance record and the licensee's further review is that the calibration data sheet uses a +/- 2% of span and not the calculated tolerance. The one out-of-tolerance is the only identified issue with these components. The out-of- tolerance with PIC-477 did exceed what has been defined as acceptable limits; however, as there was only one issue, the licensee determined it was only an issue on a rare occasion.

Based on this review, the NRC staff finds the extension of the listed function of SR 3.3.4.3 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.4 Remote Shutdown System

SR 3.3.4.3 Perform CHANNEL CALIBRATION for each required instrumentation channel

Table B 3.3.4-1 Function 3.e: Decay Heat Removal via Steam Generators (SGs) – SG Level (Wide Range)

Three differential pressure transmitters and six indications provide this indication function.

No tolerance is listed on the calibration data sheets for these components. No calculation exists for these components. Licensee procedure MMM-006 provides maintenance personnel with standard tolerances to use when none are specified. Per MMM-006, the tolerance for the transmitters is +/- 0.5% of span and for indicators the tolerance is +/- 2% span; therefore, the licensee used these as the acceptable limits for this review. These indicators are located at the charging pump room remote shutdown panel, and at the secondary remote shutdown panel. HBRSEP TS Bases Table B 3.3.4-1 indicates the required number of functions is one per SG.

In 2012, an indicator, LI-607B-2, was found failed. The indicator was replaced. The licensee stated that the issue would have been identified during performance of a licensee procedure, OST-918, which supports a monthly surveillance, SR 3.3.4.1. Therefore, the licensee determined that extending this surveillance interval to support a 24-month fuel cycle would not have resulted in an increase in time for which the component would have failed.

In 2015, the licensee surveillance record did not have calibration data sheets for three indicators, LI-607A-1, LI-607B-1, and LI- 607C-1. The surveillance record completion notes do not make reference to the indicators. The surveillance record package has the 'SC' code for

each of these indicators, which means satisfactory completion with no mention of making any adjustments. With no evidence contrary to satisfactory completion, the licensee considered that these calibrations meet acceptable limits. Further, in its RAI responses dated January 8, 2018 (Reference 5), the licensee stated that previous data and the data subsequent to this time was within the allowable tolerances and no adjustments were made. Based on the surveillance history, the NRC staff concludes the licensee response is satisfactory.

Based on this review, the NRC staff finds the extension of the listed function of SR 3.3.4.3 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.4 Remote Shutdown System

SR 3.3.4.3 Perform CHANNEL CALIBRATION for each required instrumentation channel

Table B 3.3.4-1 Function 3.f: Decay Heat Removal via Steam Generators (SGs) – Condensate Storage Tank Level

One differential pressure transmitter and indication provide this indication function.

The licensee identified no issues during its review of the surveillance testing records.

Based on this review, the NRC staff finds the extension of the listed function of SR 3.3.4.3 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.4 Remote Shutdown System

SR 3.3.4.3 Perform CHANNEL CALIBRATION for each required instrumentation channel

Table B 3.3.4-1 Function 4.a: RCS Inventory Control – Pressurizer Level

One differential pressure transmitter and indications provide this function.

In 2005, the differential pressure transmitter, LT-607D, was found out-of-tolerance. However, no tolerance was indicated on the calibration data sheet. In this case, the licensee's plant procedure, MMM-006, specifies the use of a tolerance of 0.5% for transmitters. All as-found values were within the standard tolerance allowed by MMM-006; therefore, this will not be considered to exceed acceptable limits.

Based on this review, the NRC staff finds the extension of the listed function of SR 3.3.4.3 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.4 Remote Shutdown System

SR 3.3.4.3 Perform CHANNEL CALIBRATION for each required instrumentation channel

Table B 3.3.4-1 Function 4.c: Reactor Coolant System (RCS) Pressure Control—Refuel Water Storage Tank Level

One differential pressure indicator/controller provides this indication function.

The licensee identified no issues during its review of the surveillance testing records.

Based on this review, the NRC staff finds the extension of the listed function of SR 3.3.4.3 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.5 Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

SR 3.3.5.2 Perform CHANNEL Calibration with Trip Setpoints as follows:

a. Loss of voltage Trip Setpoint of 328 V [volts] +/- 10% with a time delay of ≤ 1 second (at zero voltage):

Four undervoltage relays provide this function. Two undervoltage relays monitor the voltage of each of the two, 480V Emergency Buses. This is an one-out-of-two logic scheme. Since there is no TS Allowable Value for this function, the review will use the tolerance specified in the TS SR as the "acceptable limit."

TS 3.3.8 Auxiliary Feedwater (AFW) System Instrumentation

SR 3.3.8.4 Perform CHANNEL CALIBRATION

Table 3.3.8-1 Function 3: Loss of Offsite Power:

Four undervoltage relays provide this function. Two undervoltage relays monitor the voltage of each of the two, 480V Emergency Buses. This is an one-out-of-two logic scheme. Since there is no TS Allowable Value for this function, the review will use the tolerance specified in the TS SR of ≤ 1 second as the "acceptable limit."

In 2010, both relays of the E2 bus were found out-of-tolerance high (time setting); however, they were found at approximately 0.81 seconds during calibration which is below the SR specified time of ≤ 1 second. The SR has been used because there is no uncertainty calculation for this function and there is no TS allowable value. Since the SR specified value was met there was no loss of safety function.

Based on this review of surveillance testing, the NRC staff finds the extension of the listed functions of SR 3.3.5.2 and SR 3.3.8.4 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.5 Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

SR 3.3.5.2 Perform CHANNEL Calibration with Trip Setpoints as follows:

b. Degraded voltage Trip Setpoint of 430 V +/- 4V with a time delay of 10 +/- 0.5 seconds:

Six undervoltage relays provide this function. Three undervoltage relays monitor the voltage of each of the two, 480V Emergency Bus. This is a two-out-of-three logic scheme. Since there is no TS Allowable Value for this function, the review will use the tolerance specified in the TS SR as the "acceptable limit."

The licensee stated that its review of surveillance testing identified no issues that required further review.

Based on this review of surveillance testing, the NRC staff finds the extension of the listed function of SR 3.3.5.2 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.6 Containment Ventilation Isolation Instrumentation

SR 3.3.6.7 Perform CHANNEL CALIBRATION

Table 3.3.6-1 Items 3.a: Containment Radiation – Gaseous

Table 3.3.6-1 Items 3.b: Containment Radiation – Particulate

Radiation monitors R-11 and R-12 provide signals to the Containment Ventilation Isolation logic.

TS 3.4.15 RCS Leakage Detection Instrumentation

SR 3.4.15.4 Perform CHANNEL CALIBRATION of the required containment atmosphere radioactivity monitor

Radiation monitors provide alarm and indication functions.

Two issues with a radiation monitor, R-11, in 2005 and 2015 are the only identified problems with this function. The two occurrences of exceeding acceptable limits are not consecutive. Based on the two occurrences being several years apart, the licensee considers the surveillance history meets the rare occasion acceptance criteria.

Based on this review, the NRC staff finds the extension of the listed functions of SR 3.3.6.7 and SR 3.4.15.4 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.3.7 Control Room Emergency Filtration System (CREFS) Actuation Instrumentation

SR 3.3.7.6 Perform CHANNEL CALIBRATION

Table 3.3.7-1 Function 2: Control Room Radiation Monitor

The NRC staff notes the licensee did not request an extension to this SR function but included it its historical surveillance review.

Radiation Monitor R-1 and associated equipment was replaced during Refueling Outage 29 in 2015; therefore, the licensee determined that no meaningful conclusion can be drawn from a historical surveillance review. Based on the equipment being newly installed, the licensee could not make a determination of the acceptability for operation at 24-months between calibrations. Therefore the licensee stated that it will leave this SR as an 18-month frequency. The licensee noted that only the control room radiation monitor function for SR 3.3.7.6 is affected by the 18-month frequency.

TS 3.4.12 Low Temperature Overpressure Protection (LTOP) System

SR 3.4.12.7 Perform CHANNEL CALIBRATION for each required PORV actuation channel

Two pressure transmitters provide input to this function along with the associated rack equipment. Input is also provided from each of the three cold leg, wide range temperature loops.

The licensee stated that the calibrated components in the cold leg, wide range temperature loops are the low level amplifiers associated with RCS cold leg RTDs. The low level amplifiers are calibrated as part SR 3.3.3.2 Function 5; however, the licensee evaluated them with SR 3.4.12.7. The licensee used the as-found values listed in RNP-I/INST-1127 as the "acceptable limits" for review of this function.

No issued were identified in regards to the pressure transmitters.

In 2007, the licensee found one component of rack equipment, TM-502, failed. No as-found readings could be obtained. The plant was in Mode 1 at the time. The LTOP System is required in Mode 4, 5, or 6 (with head on vessel). The licensee determined that this failure would not have been identified by other means; however, it was not required to be operable at the time. Since this is the only failure of this component or the same component in another loop, the licensee did not consider its failure to exceed acceptable limits except on rare occasions.

In 2013, the licensee found a different component of rack equipment, QM-502, out-of-tolerance, high at one calibration point; however, it was within the calculated as-found values listed in Section 6.12 of Setpoint Calculation RNP-I/INST-1127; therefore, it did not exceed "acceptable limits." No issues were identified in regards to the low level amplifiers of the cold leg, wide range temperature loops.

Based on this review of surveillance testing, the NRC staff finds the extension of the listed function of SR 3.4.12.7 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.4.14 RCS Pressure Isolation Valves (PIVs)

SR 3.4.14.2 Verify RHR System interlock prevents the valves from being opened with a simulated or actual RCS pressure signal > 474 psig

One pressure transmitter and one rack component provide this interlock to the controls of valve RHR-750. The licensee stated that any calibration out-of-tolerance conditions identified are compared to the as-found/as-left values of Section 9 of RNP-I/INST-1126 to determine if acceptable limits were exceeded.

The licensee did not identify any issues that required further review. Based on this review of surveillance testing, the NRC staff finds the extension of the listed function of SR 3.4.14.2 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.4.15 RCS Leakage Detection Instrumentation

SR 3.4.15.5 Perform CHANNEL CALIBRATION of the required containment fan cooler condensate flow rate monitor

Four differential pressure transmitters and four indicator/relays provide indication for this function. There are no TS setpoints or Allowable Values; therefore, the calibration tolerance will be used for the acceptable limits criteria.

In 2005, two pressure transmitters, LT-702 and LT-703, were found out-of-tolerance high with respect to setpoint. This would have resulted in higher level reading than compared to actual level; however, the transmitters were still capable of responding to an increase in level.

In 2008 all four pressure transmitter were found out-of-tolerance low with respect to setpoint. This would have resulted in a lower level reading than compared to actual level; however, the transmitters were still capable of responding to an increase in level.

In 2010 all four pressure transmitters were found out-of-tolerance high with respect to setpoint. This would have resulted in a higher level reading than compared to actual level; however, the transmitters were still capable of responding to an increase in level.

In 2013, LT-703 and LT-704 were found out-of-tolerance low with respect to setpoint. This would have resulted in a lower level reading than compared to actual level; however, the transmitters were still capable of responding to an increase in level.

In 2015, LT-703 was found out-of-tolerance high with respect to setpoint. This would have resulted in a higher level reading than compared to actual level; however, the transmitter was still capable of responding to an increase in level.

In 2012, LI-704 was found out-of-tolerance at the High-High level alarm setpoint; however, the alarm was still functional on an increase in level.

The licensee stated that this system is used to detect RCS leakage based on TS Bases B 3.4.15. The capability of the system to provide alarm function on an increase in standpipe level can be used to determine operability of the system. Once the high level alarm is received, the operators use the instruments as a flow rate monitor. The rate of increase in standpipe level determines the rate of water being collected. Even if the system is out-of-tolerance, the high level alarm will be generated when the high level alarm setting is reached.

In its RAI responses dated January 8, 2018 (Reference 5), the licensee explained that the high level alarm occurs at 1 foot level (6.25% of span). The plant Annunciator Panel Procedure notes that an error of +/- 0.5 feet is acceptable. The maximum error during entire period of all readings was 0.19 feet, which is well within the acceptable alarm range error of 0.5 feet.

In addition to the TS SR, the licensee stated that operability of the level system is verified monthly by performance of the licensee procedure OST-901. That procedure ensures level in each standpipe increases when expected. Also, based on performance of the 18-month surveillances, there have been no occurrences of the equipment failing to provide an indication of an increase in level; therefore, the system would have still provided the required alarm in response to increased level in the standpipes. The level would have been slightly in error;

however, the amount of error would not have resulted in a misidentification of the sources, based on the fact the worst out-of-tolerance reading from the surveillance history was less than 0.19 feet.

Based on this review, the NRC staff finds the extension of the listed function of SR 3.4.15.5 to accommodate a 24-month fuel cycle to be acceptable.

TS 3.8.1 AC Sources – Operating

SR 3.8.1.14 Verify actuation of each sequenced load block is within +/- 0.5 seconds of design setpoint for each emergency load sequencer

Twenty-four time delay relays sequence loads onto one of two emergency buses during a Safety Injection or Station Blackout.

In 2007, four delay relays, 2-17B, 2-SID1, 2-27B, and 2-SID2, were found in out-of-tolerance condition. Upon further review, the licensee determined these out-of-tolerances did not exceed rare occasions. The basis for this conclusion is that these out-of-tolerances were not repetitive findings and were not associated with the same relays. Also, based on the number of successful tests, which required no adjustment, these components are considered highly reliable.

Based on this review, the NRC staff finds the extension of the listed function of SR 3.8.1.14 to accommodate a 24-month fuel cycle to be acceptable.

3.3 Summary of Technical Evaluation

The NRC staff has reviewed the licensee's request of proposed revisions to the TS SRs to support the implementation of a 24-month fuel cycle for the HBRSEP. The NRC staff evaluated the proposed LAR to determine whether applicable regulations and requirements continue to be met. The NRC staff found that the proposed changes do not require any exemptions or relief from regulatory requirements. Applicable regulatory requirements will continue to be met, adequate defense-in-depth will be maintained, and sufficient safety margins will be maintained.

Therefore, the NRC staff finds the licensee's proposed TS changes to be acceptable based on existing applicable regulations, and NRC guidance. The NRC staff finds that reasonable assurance exists that the impact of the interval extensions on safety would be small.

4.0 STATE CONSULTATION

In accordance with the Commission's regulations, the State of South Carolina official was notified of the proposed issuance of the amendment on April 24, 2018. The State official had no comments.

5.0 ENVIRONMENTAL CONSIDERATION

The amendment changes a requirement with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20 and changes SRs. The NRC staff has determined that the amendment involves no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation

exposure. The Commission has previously issued a proposed finding that the amendment involves no significant hazards consideration, and there has been no public comment on such finding published in the *Federal Register* on July 5, 2017 (82 FR 31092). Accordingly, the amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendment.

6.0 CONCLUSION

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

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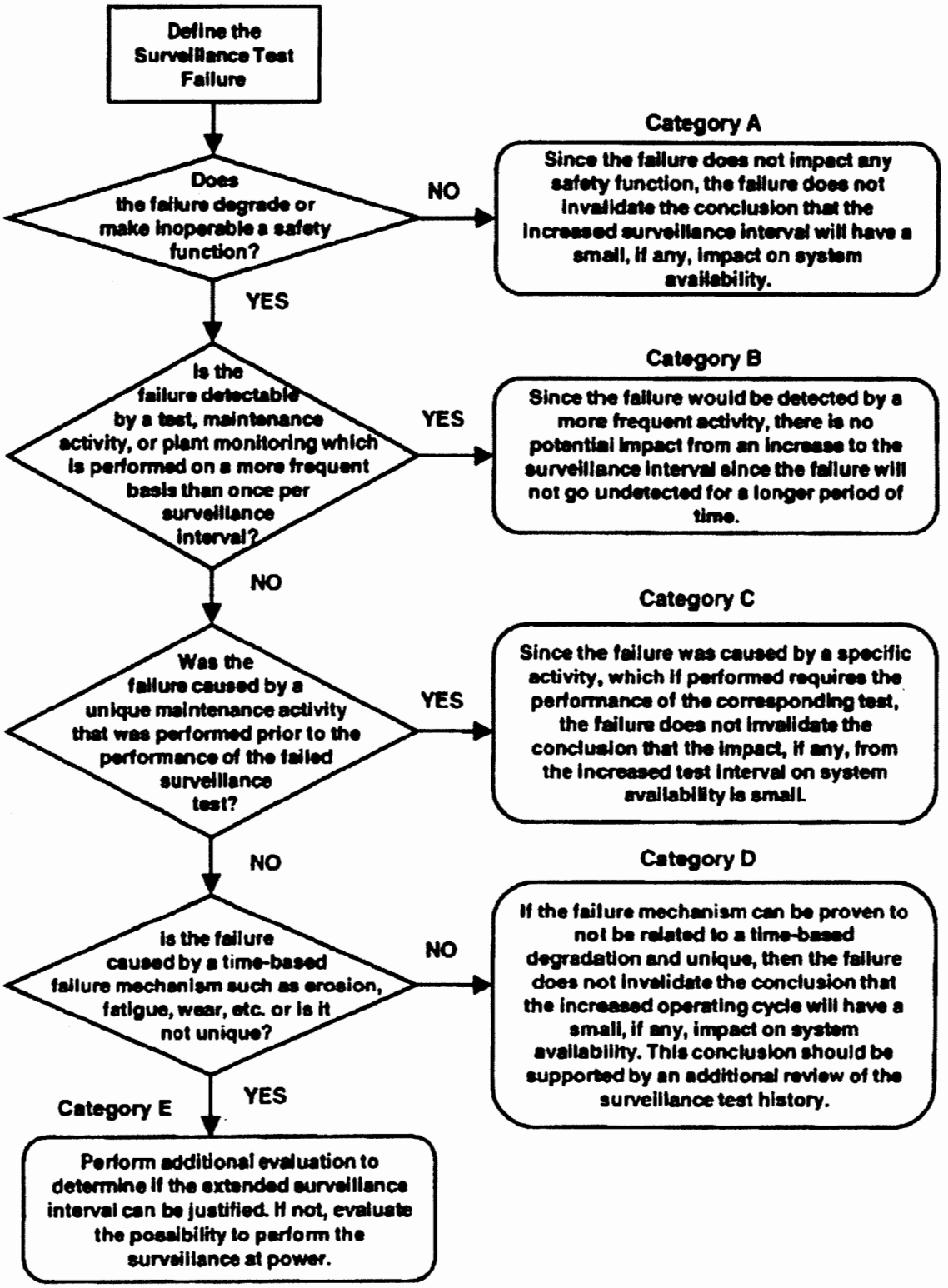
APPENDIX A – CATEGORIZATION FLOW CHART



SUBJECT: H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2 – ISSUANCE OF AMENDMENT 258 REGARDING REQUEST TO REVISE TECHNICAL SPECIFICATION SURVEILLANCE REQUIREMENT FREQUENCIES TO SUPPORT 24-MONTH FUEL CYCLES (CAC NO. MF9544; EPID L-2017-LLA-0206) DATED MAY 25, 2018

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