Benjamin C. Waldrep
Vice President
Harris Nuclear Plant
5413 Shearon Harris Road
New Hill NC 27562-9300

919.362.2502

~~SECURITY-RELATED INFORMATION – WITHHOLD UNDER 10 CFR 2.390~~
UPON REMOVAL OF ENCLOSURES 4 AND 5 THIS LETTER IS UNCONTROLLED

10 CFR 50.90

February 5, 2016
Serial: HNP-16-011

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

Shearon Harris Nuclear Power Plant (HNP), Unit 1
Docket No. 50-400
Renewed License No. NPF-63

Subject: Response to Request for Additional Information Regarding Harris Nuclear Plant License Amendment Request to Revise Technical Specifications by Relocating Specific Surveillance Frequency Requirements to a Licensee Controlled Program (TAC MF6583)

Ladies and Gentlemen:

By letter dated August 18, 2015 (Agencywide Document Access and Management System (ADAMS) Accession No. ML15236A265), as supplemented by letter dated September 29, 2015 (ADAMS Accession No. ML15272A443), Duke Energy Progress, Inc. (Duke Energy), submitted a License Amendment Request (LAR) proposing changes to the Technical Specifications (TS) for Shearon Harris Nuclear Power Plant, Unit 1 (HNP). The proposed amendment would modify HNP TS by relocating specific surveillance frequencies to a licensee-controlled program with the implementation of Nuclear Energy Institute (NEI) 04-10, "Risk-Informed Technical Specification Initiative 5B, Risk-Informed Method for Control of Surveillance Frequencies" (ML071360456).

The NRC staff reviewed the request and determined that additional information is needed to complete their review. Duke Energy received requests for additional information from the NRC on January 6 and January 22, 2016. Responses to these requests are required by February 5, and February 22, 2016 respectively.

Enclosure 1 to this letter provides the HNP response to the requests for additional information. Enclosure 2 provides a revised cross-reference between HNP TS and TSTF-425, Revision 3. Enclosure 3 provides a summary table of the Fire PRA Assessment. Enclosure 4 provides resolutions for the findings and observations (F&Os) of the fire PRA from the National Fire Protection Association (NFPA) 805 LAR review. Enclosure 5 provides resolutions for the F&Os from the 2008 Industry Peer Review. Enclosure 6 contains revised HNP TS markups.

Information in Enclosure 4 is considered security-related information under 10 CFR 2.390(d)(1).

This document contains no new Regulatory Commitments.

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In accordance with 10 CFR 50.91(b), HNP is providing the state of North Carolina with a copy of this response.

Should you have any questions regarding this submittal, please contact John Caves, Regulatory Affairs Manager, at 919-362-2406.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on February , 2016.

Sincerely,

Benjamin C. Waldrep

Enclosures:

1. Response to Request for Additional Information
2. Revised Cross-Reference between HNP Technical Specifications and TSTF-425, Revision 3
3. Assessment of the HNP Fire PRA Against the Supporting Requirements of ASME/ANS RA-Sa-2009
4. HNP Fire PRA Findings and Observations (F&O) Resolved During the NFPA 805 LAR Review Process Resolution of Fire PRA F&Os from 2008 Industry Peer Review
5. Historical, Closed Fire PRA Findings and Observations (F&O) From Peer Reviews Conducted Prior to the 2008 Industry Peer Review
6. Revised HNP Technical Specification Markups

cc: Mr. J. D. Austin, NRC Sr. Resident Inspector, HNP
Mr. W. L. Cox, III, Section Chief, N.C. DHSR
Ms. M. Barillas, NRC Project Manager, HNP
NRC Regional Administrator, Region II

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SERIAL HNP-16-011

ENCLOSURE 1

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION

SHEARON HARRIS NUCLEAR POWER PLANT, UNIT 1

DOCKET NO. 50-400

RENEWED LICENSE NUMBER NPF-63

(13 PAGES)

Shearon Harris Nuclear Power Plant, Unit No. 1
Docket No. 50-400 / Renewed License No. NPF-63

Response to Request for Additional Information Regarding Harris Nuclear Plant License Amendment Request to Revise Technical Specifications by Relocating Specific Surveillance Frequency Requirements to a Licensee-Controlled Program

Response for Request for Additional Information

1.0 INTRODUCTION

By letter dated August 18, 2015 (Agencywide Document Access and Management System (ADAMS) Accession No. ML15236A265), as supplemented by letter dated September 29, 2015 (ADAMS Accession No. ML15272A443), Duke Energy Progress, Inc. (Duke Energy), submitted a License Amendment Request (LAR) proposing changes to the Technical Specifications (TS) for Shearon Harris Nuclear Power Plant, Unit 1 (HNP). The proposed amendment would modify HNP TSs by relocating specific surveillance frequencies to a licensee-controlled program with the implementation of Nuclear Energy Institute (NEI) 04-10, "Risk-Informed Technical Specification Initiative 5B, Risk-Informed Method for Control of Surveillance Frequencies" (ML071360456).

The NRC staff reviewed the request and determined that additional information is needed to complete their review. On January 6, 2016 (Reference 1), Duke Energy received a request from the NRC for additional information regarding nine questions related to the technical adequacy of the internal events probabilistic risk assessment (PRA). Response to these items is required by February 5th, 2016. Further, on January 22nd, 2016 (Reference 2) the NRC requested additional information regarding four questions related to the Technical Specification markups in the original LAR (Reference 3). Response to these items is required by February 22th, 2016.

Reponses to the January 6 and January 22 requests for additional information (RAIs) are presented below. Reference 1 RAIs will be identified as “NRC R1 RAI-X” and Reference 2 RAIs will be identified as “NRC R2 RAI-X.”

References

1. NRC Email, Martha Barillas (NRC) to John Caves (Duke Energy), *Harris TSTF-425 LAR Draft RAI*, dated January 6, 2016
2. NRC Email, Martha Barillas (NRC) to John Caves (Duke Energy), *Harris Draft RAI STSB TSTF_425 LAR (MF6583)*, dated January 22, 2016
3. Duke Energy Letter, *Application for Technical Specification Change Regarding Risk-Informed Justification for the Relocation of Specific Surveillance Frequency Requirements to a Licensee Controlled Program,* dated August 18, 2015 (ML15236A265)
4. Duke Energy Letter, *Supplement to Harris Nuclear Plant Application for Technical Specification Change Regarding Risk-Informed Justification for the Relocation of*

Specific Surveillance Frequency Requirements to a Licensee Controlled Program, dated September 29, 2015 (ML15272A443)

2.0 REQUESTS FOR ADDITIONAL INFORMATION

NRC R1 RAI-1

In supplement dated September 29, 2015 [Reference 4], the licensee submitted a summary of the gap assessment of the internal events Probabilistic Risk Assessment (PRA) against the requirements of the PRA Standard American Society of Mechanical Engineers (ASME)/American Nuclear Society (ANS) RA-Sa-2009, as endorsed by Regulatory Guide (RG) 1.200, Revision 2. These tables indicate that all supporting requirements (SR) were met, but no Findings and Observation (F&Os) were provided. Provide a list of F&Os, if any, from the gap assessment and disposition for the application.

Duke Energy Response to NRC R1 RAI-1

The 2007 focused industry peer review of the HNP Internal Events PRA provides the review of record required by the ASME/ANS PRA Standard. The focused peer review utilized the version of the ASME/ANS PRA Standard that was in place at that time, AMSE Standard RA-Sb-2005, and Regulatory Guide (RG) 1.200, Rev. 1. Resolution of the F&Os from the focused peer review are included as Table 1 of the LAR supplement (Reference 4).

In 2015, Duke Energy performed an internal gap assessment of the 2007 F&Os, the current HNP Model of Record (MOR2010), and all permanent plant modifications and engineering changes (ECs) that have been implemented since MOR2010 (through the HNP Refueling Outage 19) against the requirements of ASME/ANS PRA Standard RA-Sa-2009, as endorsed by Regulatory Guide (RG) 1.200, Revision 2. The status of the model, as compared against the Standard, is provided in Tables 2-9 of the LAR supplement (Reference 4). No new or additional F&Os were identified as a result of the gap assessment.

NRC R1 RAI-2

F&O DA-D6-03 provided in Table 1 of supplement dated September 29, 2015 found that the generic Common Cause Failure (CCF) Multiple Greek Letters (MGL) parameters used in the HNP's PRA were not assessed to whether they reflect the plant specific testing practices, i.e. staggered vs. non-staggered testing. In its disposition to this F&O, the licensee identified a number of components which did not use the appropriate testing scheme. Clarify whether the parameters for CCF events in the Shearon Harris Nuclear Power Plant Unit 1 (HNP's) PRA represent the appropriate plant specific testing scheme. If not, update the PRA to reflect the current testing scheme, consistent with the guidance in NEI 04-10.

Duke Energy Response to NRC R1 RAI-2

The appropriate, plant-specific testing scheme is used for the Common Cause Failure (CCF) Multiple Greek Letters (MGL) parameters in the HNP model of record. HNP performs staggered testing and maintenance on major safety train equipment. In 2008, a full review of the modeled components identified a few components where it would be more appropriate to apply a non-staggered common cause factor. Examples of components typically tested on a non-staggered basis include Auxiliary Feedwater (AFW) check valves, High Head Safety Injection (HHSI) check valves, Low Head Safety Injection (LHSI) check valves, steam generator (SG) power operated relief valves (PORVs), SG safety relief valves (SRVs), pressurizer (PZR) PORVs, and PZR SRVs.

In response to F&O DA-D6-03, MGLs were re-assessed, and the Harris component database notebook sections pertaining to common cause failures were updated to align with the appropriate plant specific testing scheme. The following actions were taken:

a) Common cause basic events listed in the PRA were reviewed to determine whether CCF MGL parameters were appropriately applied.
b) Where basic events had MGLs for staggered testing when non-staggered MGLs were more appropriate (and *vice versa*), new MGLs were derived.
c) Data conversions and techniques described in the Harris component database notebook were updated.

The MGL parameters for CCF events in HNP's PRA model of record represent the appropriate plant specific testing scheme.

NRC R1 RAI-3

F&O DA-D6-01 provided in Table 1 of supplement dated September 29, 2015 [Reference 4], identified that the component boundaries from the generic data source used for CCF events are not consistent with the boundaries for component independent failure data. In its resolution the licensee identified three instances where the boundaries did not match: Emergency Diesel Generator (EDG) output breakers were changed to be included in the EDG component boundary; battery charger input and output breakers were changed to be included in the component boundary, and Auxiliary Feedwater Turbine Driven Pump trip and governor valves were changed to be included in the component boundary. Confirm that after modifying the component boundaries in response to this F&O, partial test results are not counted as valid tests as required by SR DA-C10 (see F&O DA-C10-01).

Duke Energy Response to NRC R1 RAI-3

The HNP PRA Model of Record was reviewed with regard to verification of component boundaries and the conclusion is that all appropriate components are captured within the designated component boundaries. The three identified instances where the boundaries were modified were reviewed as part of this response to confirm that all components within the new boundaries are tested with a full surveillance test.

A review of Operations Surveillance Test, OST-1411, *Auxiliary Feedwater Pump 1X-SAB Operability Test Quarterly Interval Mode 1,2,3,* Attachment 4, shows that the trip, governor, and throttle valves are stroked and timed for each test, thereby providing confidence that the additional components added to the system boundary are tested with the master component and that partial tests are not included. This was verified with Operations.

A review of the Operations Surveillance Tests, OST-1085, *1A-SA Diesel Generator Operability Test Semiannual Interval Modes 1-6*, and OST-1086, *1B-SB Diesel Generator Operability Test Semiannual Interval Modes 1-6*, verified that the additional diesel generator components added to the system boundary are tested with the master component, and that partial tests are not included. This was verified with Operations.

A review of the Maintenance Surveillance Test, MST-E0014, *1E Battery Charger Capacity Test,* and Process Instrument Calibration, PIC-E050, *C&D Battery Charger Relay Card Calibrations,* for the 125V DC Battery Chargers verified that the additional components added to the system boundary are tested with the master component and that partial tests are not included. This was verified with Operations.

NRC R1 RAI-4

F&O HR-F2-01 provided in Table 1 of supplement dated September 29, 2015 [Reference 4] states that the peer review team could not find any evidence that sequence specific timing estimates were used in the Human Failure Events (HFE) analysis, as required by SR HR-F2. The discussion in the F&O and its resolution refers specifically to the Feed and Bleed (F&B) case. The licensee states that F&B initiated at 75 minutes is the limiting time used for transient sequences and performed MAAP runs to confirm that this timing is appropriate for Steam Generator Tube Rupture (SGTR) and small Loss of Coolant Accident (LOCA) scenarios. F&B operator timing may relate to different events, such as the time from the initiating event, time to Steam Generator (SG) dryout, time to primary system saturation, or other possible events. F&B may not be successful if initiated too late.

a. Discuss the F&B operator timing in terms of the events which relate to success and failure of F&B and the supporting thermal-hydraulic analysis for core cooling. If time beyond SG dryout or primary system saturation is credited, explain this credited time.
b. If 75 minutes is bounding where F&B is credited in the PRA, explain why this is the case.
c. The F&O states that the review team could not find evidence that sequence specific timing estimates were used, and that F&B was a particular case that was examined. The F&O resolution only discusses the F&B case. The F&O appears to be more general. Please discuss the resolution of the review team's broader statement regarding evidence of the sequence specific timing.

Duke Energy Response to NRC R1 RAI-4

a. Modular Accident Analysis Program (MAAP) runs were performed to confirm that the current timing for feed and bleed initiation used in the Human Reliability Analysis (HRA) was appropriate for transients, steam generator tube rupture (SGTR), and small break loss of cooling accidents (LOCAs). For timing initiation from 20-75 minutes, no core damage was predicted and tests results were successful. An additional MAAP run was conducted in which feed and bleed was initiated at 90 minutes and the results indicated only a "partial failure." This is documented in the HNP Success Criteria Notebook.

   Four additional cases were performed: one case for SGTR, and three cases for the small break LOCA (S1) upper, middle, and lower break range. Dry-out of the steam generators was estimated to occur at approximately 55 minutes, but core damage did not occur in any of the cases for feed and bleed initiated at 75 minutes, which is the limiting time used for transient sequences. The Success Criteria calculation was updated to reflect the additional MAAP runs.

Considering the results of the MAAP analysis, 90 minutes was assessed to be a breakpoint where feed and bleed cooling may not provide adequate cooling to preclude fuel damage prior to eventually cooling the core. To account for the uncertainties in MAAP, 75 minutes (20 minutes beyond the estimated steam generator dry-out time) is assumed as the time by which feed and bleed cooling must be initiated in order to prevent core damage.

The associated MAAP calculations are documented in the HNP Thermal Hydraulic Analysis calculation. The discussion of timing associated with steam generator dry-out is documented in the HNP Success Criteria Development Calculation.

b. Core damage did not occur in any case for feed and bleed initiated at 75 minutes, which is the limiting time used for transient sequences (see the discussion in part a).

c. Evidence of sequence specific timing in the HNP HRA is documented in the HNP PRA Human Reliability Analysis notebook and the Harris Fire PRA – Human Reliability Analysis notebook. The following table of Human Error Probabilities (HEP) extracted from those notebooks shows examples where thermal hydraulic analysis (T-H) is used in deriving sequence specific timing estimates for various HEPs, per the requirements of the Standard.

Source	HEP	Use of T-H
Harris Fire PRA – Human Reliability Analysis	OPER-9: Failure to initiate RCS cool down to use LPSI/RHR for S1 and Transient LOCAs.	Determine when cool down must be initiated to prevent core damage
Harris Fire PRA – Human Reliability Analysis	OPER-17: Failure to establish recirculation (HHSI).	Determine RWST depletion timing
Harris Internal Events PRA – Human Reliability Analysis	OPER-5: Failure to Open CTMT Spray sump valves following auto failure.	To determine the hydrogen production and peak containment pressure for documentation.
Harris Internal Events PRA – Human Reliability Analysis	OPER-16: Failure to manually close Phase A Valves.	To Determine time to core damage following RCP Seal LOCA.
Harris Internal Events PRA – Human Reliability Analysis	OPER-47: Failure to Manually start RHR pumps.	To estimate the time to core damage following LOCAs (other than large break (LB) LOCAs).
Harris Internal Events PRA – Human Reliability Analysis	OPER-49: Failure to align alt. HHSI Path.	Time of core damage following a 3” LOCA.

NRC R1 RAI-5

In historical F&O 57-HR-H2 provided in Table 10 of the supplement dated September 29, 2015, [Reference 4] the peer review team investigated the human-error probability (HEP) dependency combinations. HEP OPER 70 credits installation of a spare Charging Safety Injection Pump (CSIP) after failure of the running pump. In resolution related to HEP OPER-Q14, the licensee states that HNP has a success path with secondary cooling and Residual Heat Removal (RHR) recirculation without service water. Further the licensee states that OPER 42 is a non-proceduralized action. The staff is not able to conclude whether these success criteria are credible without further detailed staff review. The staff notes non-proceduralized actions do not comply with the PRA standard and should not be credited in the PRA model. As such, provide the basis for crediting this success criteria or clarify whether the credited success criteria should be removed from the PRA model.

Duke Energy Response to NRC R1 RAI-5

Historical F&O 57-HR-H2 was generated as part of a self-assessment that was completed in advance of the 2007 Industry Group Peer Review of the HNP Internal Events PRA. The F&O was resolved prior to the peer review, and the self-assessment and F&O resolutions were provided as inputs to the review. The Peer Review Team assessed HR-H2 to be MET, so this F&O was closed with the completion of the 2007 Industry Peer Review. The bases provided to the Peer Review Team for the requested human error probability (HEP) dependency combinations are detailed below and were reviewed as part of this response. The credited success criteria meet CC-II of SR HR-H2 and were assessed to be acceptable by the independent peer review, so none should be removed from the model.

OPER-70 - Failure to Align Spare Charging Safety Injection Pump (CSIP) Pump. This operator action is performed in the switchgear room, about two minutes transit time from the control room, on the 286 ft. level of the Reactor Auxiliary Building (RAB). Two breaker racking operations are required on the bus to which the spare charging pump is being aligned. There is a transfer switch at the CSIPs that may need to be aligned, and transit time to the CSIP room is just a few minutes. This is a fully proceduralized (OP-107) and practiced evolution that is documented in the HNP Human Reliability Analysis (HRA) notebook. There are adequate cues in the Main Control Room (MCR) that prompt the operators when this action is required. The shaping factors as described in HR-G3 are addressed in the development of this operator action and are documented in the HRA Notebook. Additionally, the available manpower is addressed in the HRA Notebook.

OPER-Q14 is a post-initiator combination of operator actions:

Operator Action	Description
OPER-10	FAILURE TO START ESW PUMPS AND ALIGN VALVES
OPER-19	FAILURE TO START STANDBY NSW PUMP
OPER-9	FAILURE TO INITIATE RCS COOLDOWN TO USE LPSI/RHR FOR S1 AND TRANSIENT LOCAs
OPER-17	FAILURE TO ESTABLISH RECIRCULATION (HHSI)

This combination arises for scenarios in which there has been a loss of normal service water. If service water cooling is not restored to the CSIP and to the component cooling water (CCW) heat exchangers, the Reactor Coolant Pump (RCP) seal injection and CCW for the thermal barrier cooling will be lost, potentially resulting in a RCP seal LOCA. The first two operator actions are completely dependent because they both attempt to restore service water cooling by starting service water pumps and aligning valves as needed (OPER-19 and OPER-10). If the Emergency Service Water (ESW) fails and a seal LOCA occurs the operators need to cool down the RCS in order to allow RHR to be put in service (OPER-9) before the refueling water storage tank (RWST) is depleted and high head safety injection (HHSI) recirculation would be needed. (OPER-17).

An alternate means of cooling to the CSIP room coolers is proceduralized and available as well. This alternate task entails the opening of the subject CSIP room door and placing a fan in the doorway to provide cooler air from the RAB. Therefore, per HR-H2, these operator actions are proceduralized and operators are trained on each aspect. There are adequate cues that will alert the operators to the recovery actions provided in the procedures. The relevant performance shaping factors and manpower availability is addressed in the HRA Notebook for the individual operator actions.

OPER-42, Failure to Align CSIP Suction SI, is a Type CR human interaction that is diagnosis-driven rather than procedure-driven. Type CR human interactions represent the recovery of failed equipment or realignment of systems. CR Type events are not credited for the Harris Plant PSA without strong justification, and the detailed analysis is included in the HRA Notebook for HNP.

For this particular operator action there is higher level guidance and direction provided that will initiate the appropriate corrective/mitigative actions. Upon initiation of a Safety Injection (SI), the operators enter EOP-E-0 (Reactor Trip or Safety Injection) and the first four steps are immediate actions. As part of the procedure, an Operator is required to verify SI flow prior to securing a Reactor Coolant Pump (RCP), and verification of SI flow would provide a cue to recognize suction issues with the CSIPs. The annunciator associated with the CSIPs (pump trouble alarm) would also illuminate and would be another indication to prompt verification of CSIP diagnosis.

Verification of proper response and diagnosis of equipment, including pump suction and discharge pressures and flows, is emphasized in simulator training. Verification of proper suction/discharge parameters is also trained and is considered skill of the craft.

NRC R1 RAI-6

In the resolution to internal flooding F&O 1-3 provided in Table 1 of Enclosure 2 to the license amendment request (LAR), the licensee states that all equipment in small flood compartments and equipment within a zone of influence of the spray location is assumed to fail as a result of a spray event. However in resolution to F&Os 1-5 and 1-14 it is concluded, based on Environmental Qualification program or NEMA classification that all Motor Operated Valves (MOVs), Air Operated Valves (AOVs) and pressure, level and flow transmitters will operate as designed during and after a liquid spray event. Clarify the treatment of MOVs, AOVs and transmitters in small flood compartments and those within a zone of influence of the spray location and the basis for the conclusion.

<u>Duke Energy Response to NRC R1 RAI-6</u>

Duke Energy's response to internal flooding F&O 1-3 stated that, "For small flood compartments (FLCs), all ***susceptible*** PRA-related equipment in the compartment is assumed to fail as a result of a spray event (per the suggested resolution in the F&O)." Since Motor Operated Valves (MOVs), Air Operated Valves (AOVs), and pressure, level and flow transmitters were tested or assessed to not be susceptible to sprays, they were not failed in a FLC for spray scenarios. All other susceptible PRA-related systems, structures, and components (SSCs) in the FLCs were failed for spray scenarios.

Assessment of the susceptibility of MOVs, AOVs, and transmitters to spray included, but was not limited to, equipment testing done for the Brunswick Nuclear Plant (BNP). Submergence testing of valve actuators for 24 hours demonstrated that minor leakage into the actuator was observed. This bounds the effects of a spray event, as the in-leakage did not induce a fault. The similarity of the HNP equipment to that tested for BNP was assessed and included in the HNP Internal Flooding PRA (IFPRA).

For equipment that was not specifically tested or compared to the BNP tested equipment, Equipment Qualification (EQ) data, vendor manuals and specifications, EPRI research projects, and standards from the National Electrical Manufacturers Association (NEMA) were assessed. The assertion is that if a component:

- maintains an EQ status, or
- is weatherproof, or
- is NEMA totally enclosed non-ventilated (TENV), or
- is NEMA Type 3R and above, or
- is NEMA Type 7 (explosion-proof in a hazardous area),

then it is expected to perform its necessary function during and after being subjected to a spray event (less than 100 gpm). If, however, a component is not verified to have a sufficient NEMA rating, then its internals were verified to not have any electrical parts and were in order to not be affected by the ingress of any moisture. Otherwise, the component is considered susceptible to spray. All PRA-related MOVs, AOVs, and transmitters were assessed, classified, and documented against these criteria.

<u>NRC R1 RAI-7</u>

In internal flooding F&O 2-2 provided in Table 1 of Enclosure 2 to the LAR, the peer review team found that the licensee did not consider inter-area flood propagation through backflow through the drain system, explicitly required by SR IFSN-A8 of the ASME/ANS PRA Standard. The licensee dispositioned this finding through a sensitivity analysis. Since propagation pathways are potentially risk significant, provide the updated PRA to include those drain paths which are significant risk contributors and provide confirmation that this has been completed.

Duke Energy Response to NRC R1 RAI-7

Capability Category (CC) II supporting requirement (SR) IFSN-A8 from the ASME/ANS PRA Standard requires a licensee to:

- IDENTIFY inter-area propagation through the normal flow path from one area to another via drain lines; and areas connected via backflow through drain lines involving failed check valves, pipe and cable penetrations (including cable trays), doors, stairwells, hatchways, and HVAC ducts. INCLUDE potential for structural failure (e.g., of doors or walls) due to flooding loads.

The HNP internal flooding PRA (IFPRA) identified and included analysis of each of the potential flow paths listed in the SR. The HNP propagation analysis from one flood compartment to another includes modeling of flow through: drain lines, pipe and cable penetrations, solid bottom cable trays, floor penetrations and hatchways, stairwells, HVAC ducts, flow paths under doors, and potential structural failure of doors and other barriers. Duke Energy agrees that several of these pathways are risk significant, particularly for the large flood scenarios.

Finding and Observation (F&O) 2-2 from the IFPRA peer review identifies one specific propagation path and scenario that was not modeled correctly. For small floods (i.e., those greater than 100 gpm but less than 2,000 gpm), the capacity of the floor drain system can be exceeded, resulting in backflow into other flood compartments. The initial treatment of this scenario has been updated in the IFPRA model to address the impact of backflow through the floor drain lines.

HNP has large rooms with capacity to receive a large volume of water with no impact to PRA-related equipment. Since the floor drain system is a complex network of piping in these large rooms, simplifying assumptions were made to model the impact of backflow (as described in the F&O response). The analysis took the form of a sensitivity study that assessed the impact of backflow on the consequences and timing of the flood sequences. Because of the large rooms, there is negligible impact on any core damage sequence for the small floods. Spray scenarios are not impacted, and backflow is overwhelmed by normal propagation of the volume of the water from the break for large floods. Based on this assessment, no update to the HNP PRA model is needed, as analysis complies with the SR IFSN-A8 requirements.

NRC R1 RAI-8

If PRA models other than the internal events PRA model will be used for detailed quantitative analysis versus for qualitative or bounding analyses then please address the technical adequacy guidance in RG 1.200, Revision 2. The LAR states that the HNP fire PRA "meets the requirements of the ASME/ANS PRA Standard at an appropriate capability category to support the HNP Surveillance Frequency Control Program (SFCP)." If the fire PRA is to be used for detailed quantitative analysis, provide the F&Os and the requirements of the PRA Standard ASME/ANS RA-Sa-2009, as endorsed by RG 1.200, Revision 2, at Capability Category II, applicable to this LAR.

Duke Energy Response to NRC R1 RAI-8

The HNP fire PRA was developed using the guidance provided by NUREG/CR-6850 in support of the National Fire Protection Association (NFPA) 805, *Performance-Based Standard for Fire Protection For Light Water Reactor Electric Generating Plants,* and HNP was a pilot plant for implementation of NFPA 805. In 2008, both an NRC staff review and an Industry Group Partial-Scope Fire PRA Follow-On Peer Review were conducted on the Fire PRA. The Industry Group Peer Review compared the fire PRA against the requirements of the ANSI/ANS 58.23-2007 standard in accordance with guidance in NEI 07-12, Fire Probabilistic Risk Assessment (FPRA) Peer Review Process Guidelines. All findings have been reviewed and resolved, and the resolutions were submitted as part of the NFPA 805 LAR.

A summary of the assessment of the HNP Fire PRA against each of the supporting requirements of ASME/ANS RA-Sa-2009, as endorsed by RG 1.200, Revision 2, is provided in Enclosure 3 of this letter. Resolution of F&Os from the review were completed as part of the NFPA 805 LAR submission and are provided in Enclosure 4. The historical F&Os that were reviewed and closed as part of the 2008 Industry Peer Review are provided in Enclosure 5.

The results of the NRC staff review of the Fire PRA including F&O resolutions are documented in the HNP NFPA 805 Safety Evaluation for transition to a risk-informed, performance-based fire protection program, ADAMS Accession Numbers ML101750602 and ML101750604. Based on these reviews, the HNP fire PRA meets the requirements of the ASME/ANS PRA Standard at an appropriate capability category to support the HNP SFCP. The fire PRA will be used in accordance with NEI 04-10 to assess proposed surveillance frequency changes under the SFCP.

NRC R1 RAI-9

The LAR stated that the hazard screening performed for the Individual Plant Examination of External Events (IPEEE) studies will be used to assess seismic and other external events (external flood, high winds, transportation and nearby facilities). Since the IPEEE studies are outdated, confirm that qualitative and bounding analyses for the SFCP will evaluate these external event hazards reflecting the current plant configuration and operation as well as current risk insights and operating experience, as applicable.

Duke Energy Response to NRC R1 RAI-9

Duke Energy confirms that qualitative bounding analysis of external events for the SFCP will reflect the current plant configuration, operation, risk insights, and operating experience, as appropriate, in place of the Individual Plant Examination of External Events (IPEEE).

In 2014, for example, HNP completed a Seismic Hazard Evaluation and Screening Report in response to NRC 10 CFR 50.54(f) regarding recommendations of the Near-Term Task Force (NTTF) review of insights from the Fukushima Dai-ichi accident. Bounding seismic assessment of SSCs impacted by frequency changes under the SFCP will utilize this hazard information along with current plant conditions and insights from other ongoing Fukushima Dai-ichi seismic work, as appropriate, in place of the IPEEE seismic hazard analysis.

Similarly, for external flooding analyses, Duke Energy will utilize the 2013 HNP Flood Hazard Reevaluation Report completed in response to NRC 10 CFR 50.54(f) regarding recommendations of the NTTF review of insights from the Fukushima Dai-ichi accident in place of the IPEEE external flooding study. For all other external events, the best available information will be used to perform bounding qualitative analyses.

NRC R2 RAI-1

Page 3 of 22 of Attachment 6 of the LAR notes that HNP SR 4.1.2.3.2 is similar to TSTF-425 SRs 3.4.12.1 and 3.4.12.2 but no markup proposing changes to HNP SR 4.1.2.3.2 is included in Enclosure 3, “Proposed Technical Specification Changes.” If HNP intends to relocate the surveillance frequency of SR 4.1.2.3.2 to a surveillance frequency control program submit a markup of the proposed change.

Duke Energy Response to NRC R2 RAI-1

SR 4.1.2.3.2 was not intended to be included in the SFCP based upon the four exclusion criteria in TSTF-425, Revision 3. Enclosure 2 of this submittal provides a revised version of the Reference 3 LAR Enclosure 6 table which no longer references SR 4.1.2.3.2.

NRC R2 RAI-2

Do the markups for HNP SR Tables 4.3-6 and 4.3-7 mean that each instance of either “M,” “R,” or “Q” will be replaced with “SFCP?” For example, these markups are unclear and differ from the markups in HNP SR Table 4.3-3 where each instance of a SR table letter frequency designator is replaced with “SFCP.” Please explain or provide a clearer markup of HNP Tables 4.3-6 and 4.3-7.

Duke Energy Response to NRC R2 RAI-2

The markups for HNP SR Tables 4.3-6 and 4.3-7 intend to communicate that each instance of “M,” “R,” and “Q” will be replaced with SFCP. Enclosure 6 provides a new markup of these tables using a method consistent with Table 4.3-3.

NRC R2 RAI-3

The markup submitted for HNP SR 4.5.2.d contains what appears to be an administrative error. The text “At least once per 18 months” is lined-out but text “oRee” is in its place. Additionally text “At the frequency specified in the Surveillance Frequency Control Program” is specified to be included in that place. Please submit a corrected markup or explain the additional text.

<u>Duke Energy Response to NRC R2 RAI-3</u>

The insertion of “oRee” in the markup for SR 4.5.2.d was a typographical error. Enclosure 6 contains a corrected markup for the intended changes to SR 4.5.2.d.

<u>NRC R2 RAI-4</u>

The submitted markups indicate that HNP Table 4.7-1 item 2.b’s frequency of “Once per 6 months” will be placed into a surveillance frequency control program. Page 13 of 22 of Attachment 6 of the LAR notes that HNP SR 4.7.1.4, Table 4.7-1, Item 2.a is similar to TSTF-425, SRs 3.7.18.1 but no markup proposing changes to Table 4.7-1, Item 2.a is included in Enclosure 3, “Proposed Technical Specification Changes.” Does HNP also intend to relocate the surveillance frequency of Table 4.7-1, Item 2.a to a surveillance frequency control program as indicated in approved TSTF-425, Rev. 3, WOG STS Page 3.7.18-1? If so please submit a markup of the proposed change.

<u>Duke Energy Response to NRC R2 RAI-4</u>

Duke Energy does not intend to move the frequency for Table 4.7-1, Item 2.a to the SFCP. Enclosure 2 of this submittal provides a revised version of the Reference 3 LAR Enclosure 6 table which clarifies that 2.a is not intended to be included in the TS changes.

SERIAL HNP-16-011

ENCLOSURE 2

REVISED CROSS-REFERENCE BETWEEN HNP TECHNICAL SPECIFICATIONS AND TSTF-425, REVISION 3

SHEARON HARRIS NUCLEAR POWER PLANT, UNIT 1

DOCKET NO. 50-400

RENEWED LICENSE NUMBER NPF-63

(22 PAGES)

Cross-Reference between Shearon Harris Nuclear Power Plant, Unit 1 (HNP) Technical Specifications and TSTF-425, Revision 3 (NUREG-1431 Mark-up)

For HNP plant-specific surveillances that do not have a corresponding surveillance included in the NUREG-1431 mark-ups provided in TSTF-425, Duke Energy evaluated these surveillance frequencies against the four exclusion criteria delineated in TSTF-425, Revision 3. The four criteria which exclude surveillance frequencies from being relocated are:

- Frequencies that reference other approved programs for the specific interval (such as the Inservice Testing Program or the Primary Containment Leakage Rate Testing Program)
- Frequencies that are purely event driven (e.g., “Each time the control rod is withdrawn to the ‘full out’ position”)
- Frequencies that are event-driven but have a time component for performing the surveillance on a one-time basis once the event occurs (e.g. “within 24 hours after thermal power reaching ≥95%RTP”);
- Frequencies that are related to specific conditions (e.g. battery degradation, age and capacity) or conditions for the performance of a surveillance requirement (e.g., “drywell to suppression chamber differential pressure decrease).

HNP TS Surveillance Requirement (SR)	Similar TSTF-425 SR Number	Discussion of Differences
3.1.1.1 SHUTDOWN MARGIN – MODES 1 and 2		
4.1.1.1.1.b Verify control bank withdrawal within limits		NUREG-1431 does not specify a similar requirement. Relocation of this frequency is consistent with the intent of TSTF-425 and does not qualify for the exclusions discussed above.
4.1.1.1.2 Verify measured core reactivity within predicted value	3.1.2.1	
3.1.1.2 SHUTDOWN MARGIN – MODES 3, 4, and 5		
4.1.1.2.b Verify Shutdown Margin		NUREG-1431 does not specify a similar requirement. Relocation of this frequency is consistent with the intent of TSTF-425 and does not qualify for the exclusions discussed above.

HNP TS Surveillance Requirement (SR)	Similar TSTF-425 SR Number	Discussion of Differences
3.1.2.1 Boration Systems – Flow Path – Shutdown		
4.1.2.1.b Verify boric acid flow path valve positions		NUREG-1431 does not specify a similar requirement. Relocation of this frequency is consistent with the intent of TSTF-425 and does not qualify for the exclusions discussed above.
3.1.2.2 Boration Systems – Flow Path - Operating		
4.1.2.2.b Verify boric acid flow path valve positions		NUREG-1431 does not specify a similar requirement. Relocation of this frequency is consistent with the intent of TSTF-425 and does not qualify for the exclusions discussed above.
4.1.2.2.c Verify boric acid flow path automatic valve actuation		
4.1.2.2.d Verify boric acid flow path flow rate		
3.1.2.5 Boration Systems – Borated Water Source – Shutdown		
4.1.2.5.a.1 Verify borated water source boron concentration		Requirements for Modes 5 and 6 were not specified in NUREG-1431, however similar changes for Modes 1 through 4 were done in TSTF-425 SR 3.5.4.2 and 3.5.4.3. Relocation of this frequency is consistent with the intent of TSTF-425 and does not qualify for the exclusions discussed above.
4.1.2.5.a.2 Verify borated water source volume		
4.1.2.5.a.3 Verify boric acid tank solution temperature		NUREG-1431 does not specify a similar requirement. Relocation of this frequency is consistent with the intent of TSTF-425 and does not qualify for the exclusions discussed above..
4.1.2.5.b Verify RWST temperature	3.5.4.1	Requirements for Modes 5 and 6 were not specified in NUREG-1431. Relocation of this frequency is consistent with the intent of TSTF-425 and does not qualify for the exclusions discussed above.

HNP TS Surveillance Requirement (SR)	Similar TSTF-425 SR Number	Discussion of Differences
3.1.2.6 Boration Systems – Borated Water Source – Operating		
4.1.2.6.a.1 Verify borated water source boron concentration		Relocation of Frequencies is consistent with intent of TSTF-425. TSTF-425 SR 3.5.4.3 and 3.5.6.3 are not a direct correlation but contain similar actions and frequencies.
4.1.2.6.a.2 Verify borated water source volume		Relocation of Frequencies is consistent with intent of TSTF-425. TSTF-425 SR 3.5.4.2 and 3.5.6.2 are not a direct correlation but contain similar actions and frequencies.
4.1.2.6.a.3 Verify boric acid tank solution temperature		Relocation of Frequencies is consistent with intent of TSTF-425. TSTF-425 SR 3.5.4.1 and 3.5.6.1 are not a direct correlation but contain similar actions and frequencies.
4.1.2.6.b Verify RWST temperature	3.5.4.1	
3.1.3.1 Movable Control Assemblies – Group Height		
4.1.3.1.1 Verify individual rod position within group demand limit	3.1.4.1	
4.1.3.1.2 Verify rod freedom of movement	3.1.4.2	
3.1.3.2 Position Indication Systems – Operating		
4.1.3.2 Verify Demand Position Indication System and Digital Rod Position Indication System agree		Note, this not applied to NUREG-1431 SR 3.1.7.1 due to event-driven Frequency. Relocation of HNP frequency, specified as 12 hours, is consistent with intent of TSTF-425 and does not qualify for the exclusions discussed above.

HNP TS Surveillance Requirement (SR)	Similar TSTF-425 SR Number	Discussion of Differences
3.1.3.3 Position Indication Systems – Shutdown		
4.1.3.3 Verify digital rod position indicators agree with the demand position indicators		Note not applied to NUREG-1431 SR 3.1.7.1 due to event-driven Frequency Relocation of HNP frequency, specified as 18 months, is consistent with intent of TSTF-425 and does not qualify for the exclusions discussed above.
3.1.3.4 Rod Drop Time		
		NUREG-1431 does not specify a similar requirement. Relocation of this frequency is consistent with the intent of TSTF-425 and does not qualify for the exclusions discussed above.
3.1.3.5 Shutdown Rod Insertion Limit		
4.1.3.5 Verify each shutdown rod fully withdrawn	3.1.5.1	
3.1.3.6 Control Rod Insertion Limits		
4.1.3.6 Verify each control bank within insertion limits	3.1.6.2	
3.2.1 Axial Flux Difference	3.2.3A	
4.2.1.1.a Verify AFD with AFD Monitor Alarm Operable	3.2.3.1	NUREG-1431 does not specify a similar requirement. Relocation of this frequency is consistent with the intent of TSTF-425 and does not qualify for the exclusions discussed above.
4.2.1.3 Determine target AFD		NUREG-1431 does not specify a similar requirement. Relocation of this frequency is consistent with the intent of TSTF-425 and does not qualify for the exclusions discussed above.
3.2.2 Heat Flux Hot Channel Factor (FQ(Z))		
4.2.2.2.d.2 Verify measured values of $F_Q(Z)$	3.2.1.1	
3.2.3 Nuclear Enthalpy Rise Hot Channel Factor		
4.2.3.2 Verify $F^N_{\Delta H}$	3.2.2.1	

HNP TS Surveillance Requirement (SR)	Similar TSTF-425 SR Number	Discussion of Differences
3.2.4 Quadrant Power Tilt Ratio		
4.2.4.1.a Verify QPTR by calculation with alarm Operable	3.2.4.1	
4.2.4.2 Verify QPTR using movable incore detectors	3.2.4.2	
3.2.5 DNB Parameters		
4.2.5.1 Verify RCS Tavg, Pressurizer pressure, and RCS total flow rate.	3.4.1.1 3.4.1.2 3.4.1.3	
4.2.5.2 Verify RCS total flow rate by precision heat balance	3.4.1.4	
3.3.1 Reactor Trip System Instrumentation		
4.3.1.1, Table 4.3-1 Channel Check (Shiftly)	3.3.1.1	
4.3.1.1, Table 4.3-1 Channel Calibration (Daily)	3.3.1.2	
4.3.1.1, Table 4.3-1 Channel Calibration (Monthly)	3.3.1.3	
4.3.1.1, Table 4.3-1 Channel Calibration (Quarterly)		NUREG-1431 does not specify a similar requirement. Relocation of this frequency is consistent with the intent of TSTF-425 and does not qualify for the exclusions discussed above.
4.3.1.1, Table 4.3-1 Channel Calibration (Refueling)	3.3.1.10 3.3.1.12	
4.3.1.1, Table 4.3-1 Analog Channel Operational Test (Quarterly)	3.3.1.7 3.3.1.8	
4.3.1.1, Table 4.3-1 Analog Channel Operational Test (Refueling)	3.3.1.13	
4.3.1.1, Table 4.3-1 Trip Actuating Device Operational Test (Refueling)	3.3.1.14	
4.3.1.1, Table 4.3-1 Trip Actuating Device Operational Test (Quarterly)	3.3.1.9	
4.3.1.1, Table 4.3-1 Trip Actuating Device Operational Test (Monthly)	3.3.1.4	
4.3.1.1, Table 4.3-1 Actuation Logic Test (Monthly)	3.3.1.5	
4.3.1.2 Verify Reactor Trip System Response Time	3.3.1.16	

HNP TS Surveillance Requirement (SR)	Similar TSTF-425 SR Number	Discussion of Differences
3.3.2 Engineered Safety Features Actuation System Instrumentation		
4.3.2.1, Table 4.3-2 Channel Check (Shiftly)	3.3.2.1	
4.3.2.1, Table 4.3-2 Channel Calibration (Refueling)	3.3.2.9 3.3.5.3	
4.3.2.1, Table 4.3-2 Analog Channel Operational Test (Quarterly)	3.3.2.5	
4.3.2.1, Table 4.3-2 Trip Actuating Device Operational Test (Monthly)	3.3.2.7	
4.3.2.1, Table 4.3-2 Trip Actuating Device Operational Test (Refueling)	3.3.2.8	
4.3.2.1, Table 4.3-2 Actuation Logic Test (Monthly)	3.3.2.2 3.3.2.3 3.3.5.2	
4.3.2.1, Table 4.3-2 Master Relay Test (Monthly)	3.3.2.4	
4.3.2.1, Table 4.3-2 Slave Relay Test (Quarterly)	3.3.2.6	
4.3.2.1, Table 4.3-2 Slave Relay Test (Refueling)		NUREG-1431 does not specify a similar requirement. Relocation of this frequency is consistent with the intent of TSTF-425 and does not qualify for the exclusions discussed above.
4.3.2.2 Verify ESFAS Response Times	3.3.2.10	
3.3.3.1 Radiation Monitoring for Plant Operations		
4.3.3.1, Table 4.3-3 Channel Check (Shiftly)	3.3.6.1 3.3.7.1 3.3.8.1 3.4.15.1	
4.3.3.1, Table 4.3-3 Channel Calibration (Refueling)	3.3.6.9 3.3.7.9 3.3.8.5 3.4.15.3 3.4.15.4	

HNP TS Surveillance Requirement (SR)	Similar TSTF-425 SR Number	Discussion of Differences
4.3.3.1, Table 4.3-3 Digital Channel Operational Test (Quarterly)	3.3.6.6 3.3.7.2 3.3.8.2 3.4.15.2	
3.3.4.5.a Remote Shutdown System		
4.3.3.5.1, Table 4.3-6 Channel Check (Monthly)	3.3.4.1	
4.3.3.5.1, Table 4.3-6 Channel Calibration (Refueling)	3.3.4.3	
4.3.3.5.2 Verify control circuit and transfer switch capable of function	3.3.4.2	
3.3.3.6 Accident Monitor Instrumentation		
4.3.3.6, Table 4.3-7 Channel Check (Monthly)	3.3.3.1	
4.3.3.6, Table 4.3-7 Calibration (Refueling)	3.3.3.2	
3.4.1.1 Reactor Coolant Loops and Coolant Circulation – Startup and Power Operation		
4.4.1.1 Verify RCS loops in operation	3.4.4.1	
3.4.1.2 Reactor Coolant Loops and Coolant Circulation – Hot Standby		
4.4.1.2.1 Verify correct breaker alignment	3.4.5.3	
4.4.1.2.2 Verify Steam generator secondary side water levels	3.4.5.2	
4.4.1.2.3 Verify required RCS loops in operation	3.4.5.1	
3.4.1.3 Reactor Coolant Loops and Coolant Circulation – Hot Shutdown		
4.4.1.3.1 Verify correct breaker alignment	3.4.6.3	
4.4.1.3.2 Verify SG secondary side water level	3.4.6.2	
4.4.1.3.3 Verify required RHR or RCS loop operation	3.4.6.1	
3.4.1.4.1 Reactor Coolant Loops and Coolant Circulation – Cold Shutdown – Loops Filled		
4.4.1.4.1.1 Verify SG secondary side water level	3.4.7.1	
4.4.1.4.1.2 Verify required RHR loop operation	3.4.7.2	
3.4.1.4.2 Reactor Coolant Loops and Coolant Circulation – Cold Shutdown – Loops Not Filled		
4.4.1.4.2 Verify required RHR loop operation	3.4.8.1	

HNP TS Surveillance Requirement (SR)	Similar TSTF-425 SR Number	Discussion of Differences
3.4.3 Pressurizer		
4.4.3.1 Verify pressurizer water level	3.4.9.1	
4.4.3.2.c Verify pressurizer heater group capacity	3.4.9.2	
3.4.4 Relief Valves		
4.4.4.1.a Channel Calibration of actuation instrumentation		NUREG-1431 does not specify a similar requirement. Relocation of this frequency is consistent with the intent of TSTF-425 and does not qualify for the exclusions discussed above.
4.4.4.1.b Perform cycle of PORV	3.4.11.2	
4.4.4.2 Perform cycle of block valve	3.4.11.1	
4.4.4.3 Demonstrate accumulator Operable		NUREG-1431 does not specify a similar requirement. Relocation of this frequency is consistent with the intent of TSTF-425 and does not qualify for the exclusions discussed above.
3.4.6.1 Reactor Coolant System Leakage – Leakage Detection Systems		
4.4.6.1.a, Table 4.3-3 Channel Check (radioactivity monitor)	3.4.15.1	
4.4.6.1.a, Table 4.3-3 Digital Channel Operational Test (airborne and particulate radioactivity monitors)	3.4.15.2	
4.4.6.1.a, Table 4.3-3 Channel Calibration (airborne and particulate radioactivity monitor)	3.4.15.4	
4.4.6.1.b Channel Calibration (Reactor Cavity Sump Level and Flow Monitoring System)	3.4.15.3	
3.4.6.2 Reactor Coolant System Operational Leakage		
4.4.6.2.1.a Monitor containment airborne gaseous or particulate radioactivity monitor	3.4.15.1	
4.4.6.2.1.b Monitor containment sump inventory and Flow Monitoring System		NUREG-1431 does not specify a similar requirement. Relocation of this frequency is consistent with the intent of TSTF-425 and does not qualify for the exclusions discussed above.

HNP TS Surveillance Requirement (SR)	Similar TSTF-425 SR Number	Discussion of Differences
4.4.6.2.1.c Measure controlled leakage to reactor coolant pump seals	3.5.5.1	
4.4.6.2.1.d Verify RCS operational leakage	3.4.13.1	
4.4.6.2.1.e Monitor Reactor Head Flange Leakoff System		NUREG-1431 does not specify a similar requirement. Relocation of this frequency is consistent with the intent of TSTF-425 and does not qualify for the exclusions discussed above.
4.4.6.2.2.a Verify PIV leakage	3.4.14.1	
4.4.6.2.3 Verify primary to secondary leakage	3.4.13.2	
3.4.7 Reactor Coolant System Chemistry		
4.4.7, Table 4.4-3 sample Dissolve Oxygen		NUREG-1431 does not specify a similar requirement. Relocation of this frequency is consistent with the intent of TSTF-425 and does not qualify for the exclusions discussed above.
4.4.7, Table 4.4-3 sample Chloride		
4.4.7, Table 4.4-3 sample Fluoride		
3.4.8 Reactor Coolant System Specific Activity		
4.4.8, Table 4.4-4 Verify gross specific activity	3.4.16.1	
4.4.8, Table 4.4-4 Verify Dose Equivalent I-131	3.4.16.2	
4.4.8, Table 4.4-4 Determine $\bar{E}$	3.4.16.3	
3.4.9.1 Pressure/Temperature Limits – Reactor Coolant System		
4.4.9.1 Verify RCS pressure, temperature, and heatup and cooldown rates	3.4.3.1	
3.4.9.2 Pressure/Temperature Limits – Reactor Coolant System		
4.4.9.2.1 Verify RCS pressure, temperature, and heatup and cooldown rates	3.4.3.1	
3.4.9.4 Reactor Coolant System Overpressure Protection System	**3.4.12**	
4.4.9.4.1.a Perform Analog Channel Operational Test	3.4.12.8	
4.4.9.4.1.b Perform Channel Calibration	3.4.12.9	
4.4.9.4.1.c Verify PORV isolation valve open	3.4.12.6	

HNP TS Surveillance Requirement (SR)	Similar TSTF-425 SR Number	Discussion of Differences
4.4.9.4.2 Verify required vent open	3.4.12.5	
3.4.11 Reactor Coolant System Vents		
4.4.11.2.a Verify manual isolation valve position		NUREG-1431 does not specify a similar requirement. Relocation of this frequency is consistent with the intent of TSTF-425 and does not qualify for the exclusions discussed above.
4.4.11.2.b Cycle each vent path valve		
4.4.11.2.c Verify flow through vent path		
3.5.1 Accumulators – Cold Leg Injection		
4.5.1.1.a.1 Verify borated water volume and nitrogen cover pressure	3.5.1.2 3.5.1.3	
4.5.1.1.a.2 Verify accumulator isolation valves open	3.5.1.1	
4.5.1.1.b Verify boron concentration	3.5.1.4	
4.5.1.1.c Verify isolation valve operator power removed	3.5.1.5	
3.5.2 ECCS – T_{avg} Greater Than or Equal to 350°F		
4.5.2.a.1 Verify valves in correct position with power removed	3.5.2.1	
4.5.2.b.1 Verify ECCS piping is full	3.5.2.3	
4.5.2.b.2 Verify ECCS valve position	3.5.2.2	
4.5.2.d.1 Verify RHR System automatic interlock function	3.4.14.2	
4.5.2.d.2 Verify sump suction strainers	3.5.2.8	
4.5.2.e.1 Verify ECCS automatic valves actuate automatically	3.5.2.5	
4.5.2.e.2 Verify ECCS pumps start automatically	3.5.2.6	
4.5.2.g.2 Verify ECCS throttle valve stop position	3.5.2.7	
3.5.4 Refueling Water Storage Tank		
4.5.4.a.1 Verify RWST water volume	3.5.4.2	
4.5.4.a.2 Verify RWST boron concentration	3.5.4.3	
4.5.4.b Verify RWST water temperature	3.5.4.1	
3.6.1.1 Primary Containment – Containment Integrity	**3.6.1.1**	
4.6.1.1.a Verify all penetrations not capable of automatic isolation is isolated	3.6.3.3	
3.6.1.3 Containment Air Locks		
4.6.1.3 Verify only one door can be opened at a time	3.6.2.2	

HNP TS Surveillance Requirement (SR)	Similar TSTF-425 SR Number	Discussion of Differences
3.6.1.4 Containment Systems – Internal Pressure		
4.6.1.4 Verify containment pressure	3.6.4A.1	
3.6.1.5 Containment Systems – Air Temperature		
4.6.1.5 Verify containment air temperature	3.6.5A.1	
3.6.1.7 Containment Systems – Containment Ventilation Systems		
4.6.1.7.1 Verify each 42-inch purge makeup and exhaust valve sealed closed and closed	3.6.3.1	
4.6.1.7.2 Perform leakage rate testing on each containment purge valve (2-42 inch valves and 2-8 inch valves)	3.6.3.7	
3.6.2.1 Containment Spray System		
4.6.2.1.a Verify each containment spray valve in correct position	3.6.6A.1	
4.6.2.1.c.1 Verify automatic containment spray valves actuate	3.6.6A.5	
4.6.2.1.c.2 Verify containment spray pumps automatically start	3.3.6A.6	
4.6.2.1.c.3 Verify automatic valves from sump and RWST actuate to correct position	3.6.6A.5	
4.6.2.1.d Verify spray nozzles unobstructed	3.6.6A.8	
3.6.2.2 Spray Additive System		
4.6.2.2.a Verify spray additive valves in correct position	3.6.7.1	
4.6.2.2.b.1 Verify spray additive tank solution volume	3.6.7.2	
4.6.2.2.b.2 Verify spray additive tank solution concentration	3.6.7.3	
4.6.2.2.c Verify automatic spray additive valves actuate	3.6.7.4	
4.6.2.2.d Verify spray additive flow rate	3.6.7.5	
3.6.2.3 Containment Cooling System		
4.6.2.3.a.1 Operate containment cooling train fan	3.6.6A.2	
4.6.2.3.a.2 Verify containment cooling train cooling water flow	3.6.6A.3	
4.6.2.3.b Verify containment cooling trains automatically start	3.6.6A.7	
3.6.3 Containment Isolation Valves		
4.6.3.2.a Verify 'Phase A' automatic containment isolation valves actuate	3.6.3.8	
4.6.3.2.b Verify 'Phase B' automatic containment isolation valves actuate	3.6.3.8	

HNP TS Surveillance Requirement (SR)	Similar TSTF-425 SR Number	Discussion of Differences
4.6.3.2.c Verify purge makeup and exhaust. and containment vacuum relief valves actuate	3.6.3.8	
4.6.3.2.d Verify automatic containment isolation valves receiving an 'S' signal actuate	3.6.3.8	
4.6.3.2.e Verify Main Steam Isolation Valves actuate	3.7.2.2	
4.6.3.2.f Verify Main Feedwater Isolation Valves actuate	3.7.3.2	
3.7.1.2 Auxiliary Feedwater System		
4.7.1.2.1.a.1 Demonstrate each motor-driven pump satisfies performance requirements		Note not applied to NUREG-1431, SR 3.7.5.2 because Frequency is "In accordance with the Inservice Test Program." HNP Frequency is "At least once per 92 days on a STAGGERED TEST BASIS." Relocation of this frequency is consistent with the intent of TSTF-425 and does not qualify for the exclusions discussed above.
4.7.1.2.1.a.2 Demonstrate turbine-driven pump satisfies performance requirements		
4.7.1.2.1.b.1 Verify AFW valves in correct position	3.7.5.1	
4.7.1.2.1.b.2 Verify CST suction isolation valves open	3.7.5.1	
4.7.1.2.1.c.3 Verify AFW automatic valves automatically actuate	3.7.5.3	
4.7.1.2.1.c.1 Verify motor-driven AFW pumps start automatically	3.7.5.4	
4.7.1.2.1.c.2 Verify turbine-driven AFW pump starts automatically	3.7.5.4	
3.7.1.3 Condensate Storage Tank (CST)		
4.7.1.3.1 Verify CST level	3.7.6.1	
4.7.1.3.2 Verify each Emergency Service Water Valve supplying AFW is open	3.7.8.1	
3.7.1.4 Plant Systems – Specific Activity		
4.7.1.4 Table 4.7-1 Item 1 Gross Radioactivity Determination or Isotropic Analysis for Dose Equivalent I-131	3.7.18.1	
4.7.1.4 Table 4.7-1 Item 2b Isotropic Analysis for Dose Equivalent I-131 (gross radioactivity indicates ≤ 10% of limit)	3.7.18.1	

HNP TS Surveillance Requirement (SR)	Similar TSTF-425 SR Number	Discussion of Differences
3.7.2 Steam Generator Pressure/Temperature Limitation		
4.7.2 Verify steam generator pressure		NUREG-1431 does not specify a similar requirement. Relocation of this frequency is consistent with intent of TSTF-425 and does not qualify for the exclusions discussed above.
3.7.3 Component Cooling Water		
4.7.3.a Verify CCW valves in correct position	3.7.7.1	
4.7.3.b.1 Verify automatic CCW valves automatically actuate	3.7.7.2	
4.7.3.b.2 Verify CCW pumps automatically start	3.7.7.3	
4.7.3.b.3 Verify each automatic valve serving gross failed fuel detector and sample system heat exchangers automatically actuates	3.7.7.2	
3.7.4 Emergency Service Water System		
4.7.4.a Verify each valve in correct position	3.7.8.1	
4.7.4.b.1 Verify each automatic valve automatically actuates	3.7.8.2	
4.7.4.b.2 Verify each emergency service water pump and each emergency service water booster pump automatically starts	3.7.8.3	
3.7.5 Ultimate Heat Sink (UHS)		
4.7.5 Verify UHS water temperature and water level	3.7.9.1 3.7.9.2	
3.7.6 Control Room Emergency Filtration System		
4.7.6.a Operate each train	3.7.10.1	
4.7.6.b.1 Verify cleanup system satisfies in-place penetration and bypass leakage testing acceptance criteria		Note not applied to NUREG-1431, SR 3.7.10.2 because Frequency is in accordance with the Ventilation Filter Testing Program (VFTP). HNP Frequency is "18 months." Relocation of these frequencies is consistent with intent of TSTF-425 and does not qualify for the exclusions discussed above
4.7.6.b.2 Verify methyl iodide penetration within limits		
4.7.6.d.1 Verify HEPA filter and charcoal adsorber pressure drop		
4.7.6.d.2 Verify system automatically actuates	3.7.10.3	
4.7.6.d.3 Verify system maintains positive pressure	3.7.10.4	

HNP TS Surveillance Requirement (SR)	Similar TSTF-425 SR Number	Discussion of Differences
4.7.6.d.4 Verify heater capacity		Note not applied to NUREG-1431, SR 3.7.10.2 because Frequency is in accordance with the Ventilation Filter Testing Program (VFTP). HNP Frequency is "18 months." Relocation of this frequency is consistent with intent of TSTF-425 and does not qualify for the exclusions discussed above
3.7.7 Reactor Auxiliary Building (RAB) Emergency Exhaust System		
4.7.7.a Operate each train	3.7.12.1	
4.7.7.b.1 Verify cleanup system satisfies in-place penetration and bypass leakage testing acceptance criteria		Note not applied to NUREG-1431, SR 3.7.12.2 because Frequency is in accordance with the Ventilation Filter Testing Program (VFTP). HNP Frequency is "18 months." Relocation of these frequencies is consistent with intent of TSTF-425 and does not qualify for the exclusions discussed above.
4.7.7.b.2 Verify methyl iodide penetration within limits		
4.7.7.d.1 Verify HEPA filter and charcoal adsorber pressure drop		
4.7.7.d.2 Verify system automatically actuates	3.7.12.3	
4.7.7.d.3 Verify system maintains positive pressure	3.7.12.4	
4.7.7.d.4 Verify filter cooling bypass valve locked		NUREG-1431 does not specify a similar requirement. NUREG-1431, SR 3.7.12.5 requires verification that the filter bypass damper can be closed. Relocation of this frequency is consistent with intent of TSTF-425 and does not qualify for the exclusions discussed above.

HNP TS Surveillance Requirement (SR)	Similar TSTF-425 SR Number	Discussion of Differences
4.7.7.d.5 Verify heater capacity		Note not applied to NUREG-1431, SR 3.7.12.2 because Frequency is in accordance with the Ventilation Filter Testing Program (VFTP). HNP Frequency is "18 months." Relocation of this frequency is consistent with intent of TSTF-425 and does not qualify for the exclusions discussed above
3.7.13 Essential Services Chilled Water System		
4.7.13.1 Verify non-essential portions automatically isolate		NUREG-1431 does not specify a similar requirement. Relocation of this frequency is consistent with intent of TSTF-425 and does not qualify for the exclusions discussed above
4.7.13.2 Verify systems starts automatically		
3.7.14 Fuel Storage Pool Boron Concentration		
4.7.14 Verify boron concentration	3.7.16.1	
3.8.1.1 AC Sources - Operating	**3.8.1**	
4.8.1.1.1.a Verify correct breaker alignment	3.8.1.1	
4.8.1.1.1.b Verify transfer of power from offsite circuit to alternate circuit	3.8.1.8	
4.8.1.1.2.a.1 Verify each day tank level	3.8.1.4	
4.8.1.1.2.a.2 Verify main fuel oil storage tank level	3.8.3.1	
4.8.1.1.2.a.3 Verify fuel oil transfer system operates	3.8.1.6	
4.8.1.1.2.a.4 Verify each DG starts from standby conditions/steady state	3.8.1.2	
4.8.1.1.2.a.5 Verify each DG is synchronized and loaded	3.8.1.3	
4.8.1.1.2.a.6 Verify air start receiver pressure	3.8.3.4	
4.8.1.1.2.a.7 Verify DG is aligned to associated emergency buses		NUREG-1431 does not specify a similar requirement. Relocation of this frequency is consistent with intent of TSTF-425 and does not qualify for the exclusions discussed above

HNP TS Surveillance Requirement (SR)	Similar TSTF-425 SR Number	Discussion of Differences
4.8.1.1.2.b.1 Check for and remove accumulated water from day tank	3.8.1.5	
4.8.1.1.2.b.2 Check/remove accumulated water from fuel oil storage tank	3.8.3.5	
4.8.1.1.2.d Verify total particulate from sample of fuel oil storage tank		Note not applied to NUREG-1431, SR 3.8.3.2 because Frequency is in accordance with the Diesel Fuel Oil Testing Program. Relocation of this frequency is consistent with intent of TSTF-425 and does not qualify for the exclusions discussed above
4.8.1.1.2.e Verify each DG starts from standby conditions/quick start	3.8.1.7	
4.8.1.1.2.f.2 Verify DG rejects load ≥ 1078 KW, stabilizes without tripping any safety-related load		NUREG-1431 does not specify a similar requirement. Relocation of this frequency is consistent with intent of TSTF-425 and does not qualify for the exclusions discussed above
4.8.1.1.2.f.3 Verify interval between each timed load block	3.8.1.18	
4.8.1.1.2.f.4 Verify on loss of offsite power signal, de-energization, load shedding and auto-start	3.8.1.11	
4.8.1.1.2.f.5 Verify DG starts on safety injection test signal	3.8.1.12	
4.8.1.1.2.f.6 Verify on LOOP in conjunction with ECCS initiation signal	3.8.1.19	
4.8.1.1.2.f.7 Verify each DG operates for > 24 hours	3.8.1.14	
4.8.1.1.2.f.9 Verify DG capability to synchronize with offsite power, transfer loads to offsite power and proceed through shutdown sequence	3.8.1.16	
4.8.1.1.2.f.11 Verify DG rejects load between 6200 and 6400 KW	3.8.1.9 3.8.1.10	
4.8.1.1.2.f.12 Verify ECCS initiation signal overrides test mode	3.8.1.17	
4.8.1.1.2.f.13 Verify DG automatic trips bypassed on ECCS initiation signal	3.8.1.13	

HNP TS Surveillance Requirement (SR)	Similar TSTF-425 SR Number	Discussion of Differences
4.8.1.1.2.f.14 Verify each DG starts from standby conditions/quick restart	3.8.1.15	
4.8.1.1.2.g Verify simultaneous DG starts	3.8.1.20	
4.8.1.1.2.h.1 Drain each main fuel oil storage tank, remove sediment and clean		Note not applied to NUREG-1431, SR 3.8.3.2 because Frequency is in accordance with the Diesel Fuel Oil Testing Program. Relocation of this frequency is consistent with intent of TSTF-425 and does not qualify for the exclusions discussed above
4.8.1.1.2.h.2 Perform pressure test of diesel fuel oil piping		NUREG-1431 does not specify a similar requirement. Relocation of this frequency is consistent with intent of TSTF-425 and does not qualify for the exclusions discussed above
3.8.2.1 DC Sources – Operating		
4.8.2.1.a.1 Verify parameters in Table 4.8-2 meet Category A limits		HNP has not incorporated generic change TSTF-360, 'DC Electrical rewrite.' TSTF-425 relocates the frequencies of many of the DC Sources – Operating and Battery Parameter SRs. Relocation of this frequency is consistent with intent of TSTF-425 and does not qualify for the exclusions discussed above
4.8.2.1.a.2 Verify total battery terminal voltage		
4.8.2.1.b.1 Verify parameters in Table 4.8-2 meet Category B limits		
4.8.2.1.b.2 Verify no visible corrosion at terminals and connectors		
4.8.2.1.b.3 Verify average electrolyte temperature of 10 connected cells		
4.8.2.1.c.1 Verify cells, cell plates and racks show no physical damage		
4.8.2.1.c.2 Verify cell-to-cell and terminal connections clean and tight		
4.8.2.1.c.3 Verify resistance of cell-to-cell and terminal connections		
4.8.2.1.c.4 Verify battery charger capacity	3.8.4.2	

HNP TS Surveillance Requirement (SR)	Similar TSTF-425 SR Number	Discussion of Differences
4.8.2.1.d Verify battery capacity is adequate to maintain emergency loads	3.8.4.3	
4.8.2.1.e Verify battery capacity during performance discharge test	3.8.6.6	
3.8.3.1 Onsite Power Distribution - Operating		
4.8.3.1 Verify correct breaker alignment/power to distribution subsystems and indicated voltage	3.8.9.1 3.8.7.1	
3.8.3.2 Onsite Power Distribution - Shutdown	**3.8.10**	
4.8.3.2 Verify correct breaker alignment/power to distribution subsystems and indicated voltage	3.8.10.1 3.8.8.1	
3.8.4.1 Containment Penetration Conductor Overcurrent Protective Devices		
4.8.4.1.a.1.a Channel Calibration of protective relays		Relocation of this frequency is consistent with intent of TSTF-425 and does not qualify for the exclusions discussed above.
4.8.4.1.a.1.b System functional test		
4.8.4.1.a.2 Functionally testing representative sample		
4.8.4.1.b Subject each breaker to inspection and preventative maintenance		
3.8.4.2 Motor-Operated Valves Thermal Overload Protection		
4.8.4.2.a Perform Trip Actuation Device Operational Test		Relocation of this frequency is consistent with intent of TSTF-425 and does not qualify for the exclusions discussed above
3.9.1.a Boron Concentration		
4.9.1.1 Verify boron concentration	3.9.1.1	
4.9.1.2 Verify valves closed	3.9.2.1	
3.9.2 Refueling Operations – Instrumentation		
4.9.2.a Channel Check	3.9.3.1	
4.9.2.b Channel Calibration	3.9.3.2	
3.9.4 Containment Building Penetrations		
4.9.4.a Verify each containment penetration in required status	3.9.4.1	
4.9.4.b Verify containment purge and containment pre-entry purge makeup and exhaust valve automatically actuate	3.9.4.2	

HNP TS Surveillance Requirement (SR)	Similar TSTF-425 SR Number	Discussion of Differences
3.9.8.1 Residual Heat Removal and Coolant Circulation – High Water Level		
4.9.8.1 Verify one RHR loop	3.9.5.1	
3.9.8.2 Residual Heat Removal and Coolant Circulation – Low Water Level		
4.9.8.2.1 Verify one RHR loop and flow rate with level at or above vessel flange	3.9.6.1	
4.9.8.2.2 Verify one RHR loop and flow rate with level below vessel flange		
3.9.9 Containment Ventilation Isolation System		
4.9.9 Verify automatic isolation on actuation signal and ability to close from control switch	3.3.6.4 3.3.6.6	
3.9.10 Water Level – Reactor Vessel		
4.9.10 Verify water level	3.9.7.1	
3.9.11 Water Level – New and Spent Fuel Pools		
4.9.11 Verify water level	3.7.15.1	
3.9.12 Fuel Handling Building Emergency Exhaust System		
4.9.12.a Operate each train	3.7.13.1	
4.9.12.b.1 Verify cleanup system satisfies in-place penetration and bypass leakage testing acceptance criteria		Note not applied to NUREG-1431, SR 3.7.13.2 because Frequency is in accordance with the Ventilation Filter Testing Program (VFTP). HNP Frequency is "18 months." Relocation of this frequency is consistent with intent of TSTF-425 and does not qualify for the exclusions discussed above.
4.9.12.b.2 Verify methyl iodide penetration within limits		
4.9.12.d.1 Verify HEPA filter and charcoal adsorber pressure drop		
4.9.12.d.2 Verify system automatically actuates	3.7.13.3	
4.9.12.d.3 Verify system maintains negative pressure	3.7.13.4	

HNP TS Surveillance Requirement (SR)	Similar TSTF-425 SR Number	Discussion of Differences
4.9.12.d.5 Verify heater capacity		Note not applied to NUREG-1431, SR 3.7.13.2 because Frequency is in accordance with the Ventilation Filter Testing Program (VFTP). HNP Frequency is "18 months." Relocation of this frequency is consistent with intent of TSTF-425 and does not qualify for the exclusions discussed above.
3.10.1 Special Test Exceptions – Shutdown Margin		
4.10.1.1 Verify position of shutdown and control rods		NUREG-1431 does not specify a similar requirement. Relocation of this frequency is consistent with intent of TSTF-425 and does not qualify for the exclusions discussed above.
3.10.2 Special Test Exceptions – Group Height, Insertion, and Power Distribution Limits		
4.10.2.1 Verify Thermal Power level ≤85%		NUREG-1431 does not specify a similar requirement. Relocation of this frequency is consistent with intent of TSTF-425 and does not qualify for the exclusions discussed above.
4.10.2.2.a Verify $F_Q(Z)$ within limits		
4.10.2.2.b Verify $F^N_{\Delta H}$ within limits		
3.10.3 Special Test Exceptions – Physics Tests		
4.10.3.1 Verify Thermal Power ≤ 5%	3.1.8.3	
4.10.3.3 Verify T_{avg}	3.1.8.2	
3.10.4 Special Test Exceptions – Reactor Coolant Loops		
4.10.4.1 Verify Thermal Power < P-7	3.4.19.1	

HNP TS Surveillance Requirement (SR)	Similar TSTF-425 SR Number	Discussion of Differences
3.10.5 Special Test Exceptions – Position Indication System – Shutdown		
4.10.5 Verify Demand Position Indication System and Digital Rod Position Indication System agree		Note not applied to NUREG-1431, SR 3.1.7.1, due to event-driven Frequency. HNP Frequency is "24 hours." Relocation of this frequency is consistent with intent of TSTF-425 and does not qualify for the exclusions discussed above.
3.11.2.5 Explosive Gas Mixture		
4.11.2.5 Verify hydrogen and oxygen in Gaseous Radwaste Treatment System within limits		These requirements are typically relocated to the Explosive Gas and Storage Tank Radioactivity Monitoring Program (NUREG-1431, 5.5.12) during ITS conversion. The HNP Frequency is "At least once per 12 hours." Relocation of this frequency is consistent with intent of TSTF-425 and does not qualify for the exclusions discussed above.
6.8.4.p Programs (Surveillance Frequency Control Program)	**5.5.18**	

SERIAL HNP-16-011

ENCLOSURE 3

ASSESSMENT OF THE HNP FIRE PRA AGAINST THE SUPPORTING REQUIREMENTS OF ASME/ANS RA-Sa-2009

SHEARON HARRIS NUCLEAR POWER PLANT, UNIT 1

DOCKET NO. 50-400

RENEWED LICENSE NUMBER NPF-63

9 PAGES

Table 3-1 – Assessment of the HNP Fire PRA Against ASME/ANS RA-Sa-2009				
Fire Std. SR	**NRC Staff Review Results**	**Industry Peer Review Results**	**Status before NFPA 805 F&O resolution**	**Status After NFPA 805 F&O Resolution ***
PP-A1	Met	Not Reviewed	Met	Met
PP-B1	Not Met	Not Met	Not Met	CC-II/III
PP-B2	Not Met	Not Met	Not Met	CC-II/III
PP-B3	N/A	Not Reviewed	N/A	N/A
PP-B4	Met	Not Reviewed	Met	Met
PP-B5	N/A	Not Reviewed	N/A	NA
PP-B6	Met	Not Reviewed	Met	Met
PP-B7	Met	Not Reviewed	Met	Met
PP-C1	Met	Not Reviewed	Met	Met
PP-C2	Met	Not Reviewed	Met	Met
PP-C3	Not Met	Not Met	Not Met	Met
PP-C4	Met	Not Reviewed	Met	Met
ES-A1	Met	Not Reviewed	Met	Met
ES-A2	Met	Not Reviewed	Met	Met
ES-A3	Met	Not Reviewed	Met	Met
ES-A4	CC-III	Not Reviewed	CC-III	CC-III
ES-A5	CC-II	Not Reviewed	CC-II	CC-II
ES-A6	Not Met	CC-III	CC-III	CC-III
ES-B1	CC-III	Not Reviewed	CC-III	CC-III
ES-B2	CC-II	Not Reviewed	CC-II	CC-II
ES-B3	Met	Not Reviewed	Met	Met
ES-B4	Not Met	CC-III	CC-III	CC-III
ES-B5	Met	Not Reviewed	Met	Met
ES-B6	Met	Not Reviewed	Met	Met
ES-C1	Not Met	Not Met	Not Met	Met
ES-C2	CC-II	Not Reviewed	CC-II	CC-II
ES-D1	Not Met	Met	Met	Met

Table 3-1 – Assessment of the HNP Fire PRA Against ASME/ANS RA-Sa-2009, continued

Fire Std SR	NRC Staff Review Results	Industry Peer Review Results	Status before NFPA 805 F&O resolution	Status After NFPA 805 F&O Resolution *
CS-A1	Met	Not Reviewed	Met	Met
CS-A2	Met	CC-II	CC-II	CC-II
CS-A3	Not Met	Met	Met	Met
CS-A4	Not Met	Met	Met	Met
CS-A5	Met	Not Reviewed	Met	Met
CS-A6	Met	Not Reviewed	Met	Met
CS-A7	Not Met	Met	Met	Met
CS-A8	Not Met	Met	Met	Met
CS-A9	Met	Not Reviewed	Met	Met
CS-A10	CC-III	Not Reviewed	CC-III	CC-III
CS-A11	N/A	Not Reviewed	NA	NA
CS-B1	CC-II/III	Not Reviewed	CC-II/III	CC-II/III
CS-C1	Met	Not Reviewed	Met	Met
CS-C2	Met	Not Reviewed	Met	Met
CS-C3	N/A	N/A	NA	NA
CS-C4	Not Met	Met	Met	Met
QLS-A1	N/A. No qualitative screening.	Not Reviewed	NA	NA
QLS-A2	N/A. No qualitative screening.	Not Reviewed	NA	NA
QLS-A3	N/A. No qualitative screening.	Not Reviewed	NA	NA
QLS-A4	N/A. No qualitative screening.	Not Reviewed	NA	NA
QLS-B1	N/A. No qualitative screening.	Not Reviewed	NA	NA

Table 3-1 – Assessment of the HNP Fire PRA Against ASME/ANS RA-Sa-2009, continued				
Fire Std SR	**NRC Staff Review Results**	**Industry Peer Review Results**	**Status before NFPA 805 F&O resolution**	**Status After NFPA 805 F&O Resolution ***
QLS-B2	N/A. No qualitative screening.	Not Reviewed	NA	NA
QLS-B3	N/A. No qualitative screening.	Not Reviewed	NA	NA
PRM-A1	Not Met	Met	Met	Met
PRM-A2	Not Met	Met	Met	Met
PRM-A3	Met	Not Reviewed	Met	Met
PRM-A4	Met	Not Reviewed	Met	Met
PRM-A5	Met	Not Reviewed	Met	Met
PRM-A6	Met	Not Reviewed	Met	Met
PRM-B1	Not Met	Met	Met	Met
PRM-B2	Met	Not Reviewed	Met	Met
PRM-B3	N/A	NA	N/A	NA
PRM-B4	N/A	NA	N/A	NA
PRM-B5	N/A	N/A	N/A	NA
PRM-B6	N/A	N/A	N/A	NA
PRM-B7	N/A	N/A	N/A	NA
PRM-B8	Met	Not Reviewed	Met	Met
PRM-B9	N/A	Not Reviewed	N/A	NA
PRM-B10	Met	Not Reviewed	Met	Met
PRM-B11	Met	Not Reviewed	Met	Met
PRM-B12	Met	Not Reviewed	Met	Met
PRM-B13	Not Met	Met	Met	Met
PRM-B14	Not Met	Met	Met	Met
PRM-C1	Issue with Standard	Issue with Standard	Issue with Standard	CC-I ASME Inquiry
PRM-D1	Met	Not Reviewed	Met	Met

Table 3-1 – Assessment of the HNP Fire PRA Against ASME/ANS RA-Sa-2009, continued

Fire Std SR	NRC Staff Review Results	Industry Peer Review Results	Status before NFPA 805 F&O resolution	Status After NFPA 805 F&O Resolution *
FSS-A1	Met	Not Reviewed	Met	Met
FSS-A2	Not Met	Met	Met	Met
FSS-A3	Met	Not Reviewed	Met	Met
FSS-A4	Met	Not Reviewed	Met	Met
FSS-A5	CC-III	Not Reviewed	CC-III	CC-III
FSS-A6	Met	Not Reviewed	CC-I/II	CC-I/II
FSS-B1	Not Met	Met	Met	Met
FSS-B2	CC-III	Not Reviewed	CC-III	CC-III FSS-B2-01
FSS-C1	CC-II	Not Reviewed	CC-II	CC-II
FSS-C2	CC-II/III	Not Reviewed	CC-II/III	CC-II/III
FSS-C3	CC-II/III	Not Reviewed	CC-II/III	CC-II/III
FSS-C4	CC-III	Not Reviewed	CC-III	CC-III
FSS-C5	Not met	CC-I/II	CC-I/II	CC-I/II
FSS-C6	CC-I/II	Not Reviewed	CC-I/II	CC-I/II
FSS-C7	Met	Not Reviewed	Met	Met
FSS-C8	Met	Not Reviewed	Met	Met
FSS-D1	Not Met	Met	Met	Met
FSS-D2	Met	Not Reviewed	Met	Met
FSS-D3	CC-I	CC-III	CC-III	CC-III
FSS-D4	Met	Not Reviewed	Met	Met
FSS-D5	CC-III	Not Reviewed	CC-III	CC-III
FSS-D6	Met	Not Reviewed	Met	Met
FSS-D7	CC-I	CC-I	CC-I	CC-I No F&O
FSS-D8	Met	Not Reviewed	Met	Met
FSS-D9	CC-I	CC-I	CC-I	CC-I No F&O
FSS-D10	CC-II/III	Not Reviewed	CC-II/III	CC-II/III

Table 3-1 – Assessment of the HNP Fire PRA Against ASME/ANS RA-Sa-2009, continued				
Fire Std SR	**NRC Staff Review Results**	**Industry Peer Review Results**	**Status before NFPA 805 F&O resolution**	**Status After NFPA 805 F&O Resolution ***
FSS-D11	Met	Not Reviewed	Met	Met
FSS-E1	Met	Not Reviewed	Met	Met
FSS-E2	Met	Not Reviewed	Met	Met
FSS-E3	Not met	CC-I	CC-I	CC-I FSS-E3-1
FSS-E4	N/A	N/A	N/A	NA
FSS-F1	Not Reviewed	CC-I/II	CC-I/II	CC-I/II
FSS-F2	Not Reviewed	CC-I	CC-I	CC-I FSS-F-1
FSS-F3	Not Reviewed	Not Met	Not Met	Not Met FSS-F3-01
FSS-G1	Not Reviewed	Met	Met	Met
FSS-G2	Not Reviewed	Met	Met	Met
FSS-G3	Not Reviewed	Met	Met	Met
FSS-G4	Not Reviewed	CC-II	CC-II	CC-II
FSS-G5	Not Reviewed	N/A	N/A	NA
FSS-G6	Not Reviewed	CC-II/III	CC-II/III	CC-II/III
FSS-H1	Met	Not Reviewed	Met	Met
FSS-H2	CC-I	CC-II/III	CC-II/III	CC-II/III
FSS-H3	Met	Not Reviewed	Met	Met
FSS-H4	Met	Not Reviewed	Met	Met
FSS-H5	CC-I	CC-I	CC-I	CC-I FSS-H9-1
FSS-H6	CC-I	CC-I	CC-I	CC-I FSS-H9-1
FSS-H7	Met	Not Reviewed	Met	Met
FSS-H8	Not Met	Met	Met	Met
FSS-H9	Not Met	Met	Met	Met
FSS-H10	Met	Not Reviewed	Met	Met
IGN-A1	Met	Not Reviewed	Met	Met

Table 3-1 – Assessment of the HNP Fire PRA Against ASME/ANS RA-Sa-2009, continued				
Fire Std SR	**NRC Staff Review Results**	**Industry Peer Review Results**	**Status before NFPA 805 F&O resolution**	**Status After NFPA 805 F&O Resolution ***
IGN-A2	N/A	N/A	N/A	NA
IGN-A3	N/A	N/A	N/A	NA
IGN-A4	CC-I	CC-I	CC-I	CC-I IGN-A4-1
IGN-A5	Met	Not Reviewed	Met	Met
IGN-A6	N/A	N/A	N/A	NA
IGN-A7	Met	Not Reviewed	Met	Met
IGN-A8	CC-III	Not Reviewed	CC-III	CC-III
IGN-A9	Met	Met	Met	Met
IGN-A10	CC-II	Not Reviewed	CC-II	CC-II
IGN-B1	Met	Not Reviewed	Met	Met
IGN-B2	Met	Not Reviewed	Met	Met
IGN-B3	Met	Not Reviewed	Met	Met
IGN-B4	N/A	N/A	N/A	NA
IGN-B5	Met	Not Reviewed	Met	Met
QNS-A1	N/A. No quantitative screening.	Not Reviewed	N/A	NA
QNS-B1	N/A. No quantitative screening.	Not Reviewed	N/A	NA
QNS-B2	N/A. No quantitative screening.	Not Reviewed	N/A	NA
QNS-C1	N/A. No quantitative screening.	Not Reviewed	N/A	NA
QNS-D1	N/A. No quantitative screening.	Not Reviewed	N/A	NA
QNS-D2	N/A. No quantitative screening.	Not Reviewed	N/A	NA

Table 3-1 – Assessment of the HNP Fire PRA Against ASME/ANS RA-Sa-2009, continued				
Fire Std SR	**NRC Staff Review Results**	**Industry Peer Review Results**	**Status before NFPA 805 F&O resolution**	**Status After NFPA 805 F&O Resolution ***
CF-A1	Met	Not Met	Met	CC-II with ASME inquiry
CF-A2	Met	Not Reviewed	Met	Met
CF-B1	Not Met	Met	Met	Met
HRA-A1	Met	Not Reviewed	Met	Met
HRA-A2	Met	Not Reviewed	Met	Met
HRA-B1	Met	Not Reviewed	Met	Met
HRA-B2	Not Met	Met	Met	Met
HRA-B3	Not Met	Met	Met	Met
HRA-C1	Not Met	Met	Met	Met
HRA-D1	N/A	N/A	N/A	N/A
HRA-E1	Met	Not Reviewed	Met	Met
SF-A1	Not Reviewed	Not Met	Not Met	Met
SF-A2	Not Reviewed	Met	Met	Met
SF-A3	Not Reviewed	Met	Met	Met
SF-A4	Not Reviewed	Met	Met	Met
SF-A5	Not Reviewed	Met	Met	Met
SF-B1	Not Reviewed	Met	Met	Met
FQ-A1	Met	Not Reviewed	Met	Met
FQ-A2	Met	Not Reviewed	Met	Met
FQ-A3	Met	Not Reviewed	Met	Met
FQ-A4	Not Met	Met	Met	Met FQ-4A-02
FQ-B1	Met	Not Reviewed	Met	Met
FQ-C1	Met	Not Reviewed	Met	Met
FQ-D1	Not Met	Met	Met	Met FQ-D1-01
FQ-E1	Not Met	Not Met	Not Met	Met FQ-E1-01

Table 3-1 – Assessment of the HNP Fire PRA Against ASME/ANS RA-Sa-2009, continued				
Fire Std SR	**NRC Staff Review Results**	**Industry Peer Review Results**	**Status before NFPA 805 F&O resolution**	**Status After NFPA 805 F&O Resolution ***
FQ-F1	Not Met	Not Met	Not Met	Met FQ-F1-01
FQ-F2	Not Met	Not Met	Not Met	Met
UNC-A1	Not Reviewed	Met	Met	Met UNC-A1-01
UNC-A2	Not Reviewed	Met	Met	Met
UNC-A3	Not Reviewed	Met	Met	Met
MU-A1	Met	Met	Met	Met
MU-A2	Met	Not Reviewed	Met	Met
MU-A3	Met	Not Reviewed	Met	Met
MU-B1	Met	Not Reviewed	Met	Met
MU-B2	Met	Not Reviewed	Met	Met
MU-B3	Met	Met	Met	Met
MU-B4	Not Met	Not Met	Not Met	Met
MU-B5	Not Met	Not Met	Not Met	Met
MU-B6	Not Met	Not Met	Not Met	Met
MU-C1	Met	Not Reviewed	Met	Met
MU-D1	Met	Not Reviewed	Met	Met
MU-E1	Met	Not Reviewed	Met	Met
MU-F1	Met	Not Reviewed	Met	Met
MU-F2	Met	Not Reviewed	Met	Met

* The F&Os noted in far right column are those not incorporated, but they do not impact the 5b application. In general, those not incorporated are related to numerical statistical uncertainty analysis for PRA data elements which do not include the fire model inputs that are the major source of uncertainty. The discussion and justification are provided in the response to the individual F&Os below. Two of SRs listed as CC-I, FSS-D7 and FSS-D9, do not have F&Os, but are met at CC-1. For FFS-D7, outliers are not identified, and for FFS-D9, smoke damage was not evaluated.

SERIAL HNP-16-011

ENCLOSURE 6

REVISED HNP TECHNICAL SPECIFICATION MARKUPS

SHEARON HARRIS NUCLEAR POWER PLANT, UNIT 1

DOCKET NO. 50-400

RENEWED LICENSE NUMBER NPF-63

(9 PAGES)

This page is provided for information. The changes marked on this page are unchanged from the HNP TS markups provided in the original license amendment request.

LIMITING CONDITION FOR OPERATION

3.3.3.5.a The Remote Shutdown System monitoring instrumentation channels shown in Table 3.3-9 shall be OPERABLE.

3.3.3.5.b All transfer switches, Auxiliary Control Panel Controls and Auxiliary Transfer Panel Controls for the OPERABILITY of those components required by the SHNPP Safe Shutdown Analysis to (1) remove decay heat via auxiliary feedwater flow and steam generator power-operated relief valve flow from steam generators A and B, (2) control RCS inventory through the normal charging flow path, (3) control RCS pressure, (4) control reactivity, and (5) remove decay heat via the RHR system shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. With the number of OPERABLE remote shutdown monitoring channels less than the Minimum Channels OPERABLE as required by Table 3.3-9, restore the inoperable channel(s) to OPERABLE status within 7 days, or be in HOT SHUTDOWN within the next 12 hours.

b. With the number of OPERABLE remote shutdown monitoring channels less than the Total Number of Channels required by Table 3.3-9, restore the inoperable channels to OPERABLE status within 60 days or submit a Special Report in accordance with Specification 6.9.2 within 14 additional days.

c. With one or more inoperable Remote Shutdown System transfer switches, power, or control circuits required by 3.3.3.5.b, restore the inoperable switch(s)/circuit(s) to OPERABLE status within 7 days, or be in HOT STANDBY within the next 12 hours.

d. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.3.5.1 Each remote shutdown monitoring instrumentation channel shall be demonstrated OPERABLE by performance of the CHANNEL CHECK and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3-6.

4.3.3.5.2 Each Remote Shutdown System transfer switch, power and control circuit and control switch required by 3.3.3.5.b, shall be demonstrated OPERABLE ~~at least once per 18 months~~.

At the frequency specified in the Surveillance Frequency Control Program.

TABLE 4.3-6

REMOTE SHUTDOWN MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK		CHANNEL CALIBRATION
1. Reactor Coolant System Hot-Leg Temperature	~~M~~	Replace with: SFCP	~~R~~
2. Reactor Coolant System Cold-Leg Temperature	~~M~~		~~R~~
3. Pressurizer Pressure	~~M~~		~~R~~
4. Pressurizer Level	~~M~~		~~R~~
5. Steam Generator Pressure	~~M~~	Replace with: SFCP	~~R~~
6. Steam Generator Water Level--Wide Range	~~M~~		~~R~~
7. Residual Heat Removal Flow	~~M~~		~~R~~
8. Auxiliary Feedwater Flow	~~M~~		~~R~~
9. Condensate Storage Tank Level	~~M~~	Replace with: SFCP	~~R~~
10. Reactor Coolant System Pressure--Wide Range	~~M~~		~~R~~
11. Wide-Range Flux Monitor (SR Indicator)	~~M~~		~~Q~~
12. Charging Header Flow	~~M~~		~~R~~
13. a. Auxiliary Feedwater Turbine Steam Inlet--Pump Discharge ΔP	~~M~~	Replace with: SFCP	~~R~~
b. Auxiliary Feedwater Turbine Speed	~~M~~		~~R~~
14. Boric Acid Tank Level	~~M~~		~~R~~

LIMITING CONDITION FOR OPERATION

least HOT STANDBY in the next 6 hours and in at least HOT SHUTDOWN within the following 6 hours.

f. The provisions of Specification 3.0.4 are not applicable.

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* The alternate method shall be a check of safety valve piping temperatures and evaluation to determine position.

\# The alternate method shall be the initiation of the backup method as required by Specification 6.8.4.d.

SURVEILLANCE REQUIREMENTS

4.3.3.6 Each accident monitoring instrumentation channel shall be demonstrated OPERABLE by performance of the CHANNEL CHECK and CHANNEL CALIBRATION at the frequencies shown in Table 4.3-7.

TABLE 4.3-7

ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK		CHANNEL CALIBRATION
1. Containment Pressure	~~M~~		~~R~~
a. Narrow Range	~~M~~	Replace with: SFCP	~~R~~
b. Wide Range	~~M~~		~~R~~
2. Reactor Coolant Hot-Leg Temperature--Wide Range	~~M~~		~~R~~
3. Reactor Coolant Cold-Leg Temperature--Wide Range	~~M~~		~~R~~
4. Reactor Coolant Pressure--Wide Range	~~M~~		~~R~~
5. Pressurizer Water Level	~~M~~	Replace with: SFCP	~~R~~
6. Steam Line Pressure	~~M~~		~~R~~
7. Steam Generator Water Level--Narrow Range	~~M~~		~~R~~
8. Steam Generator Water Level--Wide Range	~~M~~		~~R~~
9. Refueling Water Storage Tank Water Level	~~M~~		~~R~~
10. Auxiliary Feedwater Flow Rate	~~M~~	Replace with: SFCP	~~R~~
11. Reactor Coolant System Subcooling Margin Monitor	~~M~~		~~R~~
12. PORV Position Indicator	~~M~~		~~R~~
13. PORV Block Valve Position Indicator	~~M~~		~~R~~
14. Pressurizer Safety Valve Position Indicator	~~M~~	Replace with: SFCP	~~R~~
15. Containment Water Level (ECCS Sump)--Narrow Range	~~M~~		~~R~~
16. Containment Water Level--Wide Range	~~M~~		~~R~~

1

TABLE 4.3-7 (Continued)

ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION
17. In Core Thermocouples	M	R
18. Plant Vent Stack--High Range Noble Gas Monitor	M	R
19. Main Steam Line Radiation Monitors	M	R
20. Containment--High Range Radiation Monitor	M	R*
21. Reactor Vessel Level	M	R
22. Containment Spray NaOH Tank Level	M	R
23. Turbine Building Vent Stack High Range Noble Gas Monitor	M	R
24. Waste Processing Building Vent Stack High Range Noble Gas Monitors		
a. Vent Stack 5	M	R
b. Vent Stack 5A	M	R
25. Condensate Storage Tank Level	M	R

Replace with: SFCP

Replace with: SFCP

* CHANNEL CALIBRATION may consist of an electronic calibration of the channel, not including the detector, for range decades above 10 R/h and a one point calibration check of the detector below 10 R/h with an installed or portable gamma source.

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3/4.5.2 ECCS SUBSYSTEMS - T_{avg} GREATER THAN OR EQUAL TO 350°F

LIMITING CONDITION FOR OPERATION

3.5.2 Two independent Emergency Core Cooling System (ECCS) subsystems shall be OPERABLE with each subsystem comprised of:

a. One OPERABLE Charging/safety injection pump,

b. One OPERABLE RHR heat exchanger,

c. One OPERABLE RHR pump, and

d. An OPERABLE flow path capable of taking suction from the refueling water storage tank on a Safety Injection signal and, upon being manually aligned, transferring suction to the containment sump during the recirculation phase of operation.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. With one ECCS subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

b. In the event the ECCS is actuated and injects water into the Reactor Coolant System, a Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 90 days describing the circumstances of the actuation and the total accumulated actuation cycles to date. The current value of the usage factor for each affected Safety Injection nozzle shall be provided in this Special Report whenever its value exceeds 0.70.

SURVEILLANCE REQUIREMENTS

4.5.2 Each ECCS subsystem shall be demonstrated OPERABLE:

a. ~~At least once per 12 hours~~ by:

At the frequency specified in the Surveillance Frequency Control Program

1. Verifying that the following valves are in the indicated positions with the control power disconnect switch in the "OFF" position, and the valve control switch in the "PULL TO LOCK" position:

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CP&L Valve No.	EBASCO Valve No.	Valve Function	Valve Position
1SI-107	2SI-V500SA-1	High Head Safety Injection to Reactor Coolant System Hot Legs	Closed
1SI-86	2SI-V501SB-1	High Head Safety Injection to Reactor Coolant System Hot Legs	Closed
1SI-52	2SI-V502SA-1	High Head Safety Injection to Reactor Coolant System Cold Legs	Closed
1SI-340	2SI-V579SA-1	Low Head Safety Injection to Reactor Coolant System Cold Legs	Open
1SI-341	2SI-V578SB-1	Low Head Safety Injection to Reactor Coolant System Cold Legs	Open
1SI-359	2SI-V587SA-1	Low Head Safety Injection to Reactor Coolant System Hot Legs	Closed

b. ~~At least once per 31 days~~ by:

At the frequency specified in the Surveillance Frequency Control Program

1. Verifying that the ECCS piping is full of water by venting accessible discharge piping high points, and

2. Verifying that each valve (manual, power-operated, or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

By a visual inspection which verifies that no loose debris (rags, trash, clothing, etc.) is present in the containment which could be transported to the containment sump and cause restriction of the pump suctions during LOCA conditions. This visual inspection shall be performed:

1. For all accessible areas of the containment prior to establishing CONTAINMENT INTEGRITY, and

2. Of the areas affected within containment at the completion of each containment entry when CONTAINMENT INTEGRITY is established.

SURVEILLANCE REQUIREMENTS (Continued)

At the frequency specified in the Surveillance Frequency Control Program

d. ~~At least once per 18 months~~ by:

1. Verifying automatic interlock action of the RHR system from the Reactor Coolant System by ensuring that with a simulated or actual Reactor Coolant System pressure signal greater than or equal to 425 psig the interlocks prevent the valves from being opened.

2. A visual inspection of the containment sump and verifying that the subsystem suction inlets are not restricted by debris and that the sump components (trash racks, screens, etc.) show no evidence of structural distress or abnormal corrosion.

e. ~~At least once per 18 months~~ by:

1. Verifying that each automatic valve in the flow path actuates to its correct position on safety injection actuation test signal and on safety injection switchover to containment sump from an RWST Lo-Lo level test signal, and

2. Verifying that each of the following pumps start automatically upon receipt of a safety injection actuation test signal:

   a) Charging/safety injection pump,

   b) RHR pump.

f. By verifying that each of the following pumps develops the required differential pressure when tested pursuant to the Inservice Testing Program:

1. Charging/safety injection pump (Refer to Specification 4.1.2.4)

2. RHR pump ≥ 100 psid at a flow rate of at least 3663 gpm.

g. By verifying that the locking mechanism is in place and locked for the following High Head ECCS throttle valves:

1. Within 4 hours following completion of each valve stroking operation or maintenance on the valve when the ECCS subsystems are required to be OPERABLE, and

2. ~~At least once per 18 months.~~

At the frequency specified in the Surveillance Frequency Control Program