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

Subject: Duke Energy Carolinas, LLC
Oconee Nuclear Station, Units 1, 2, and 3
Docket Numbers 50-269, 50-270, and 50-287,
Renewed Operating Licenses DPR-38, DPR-47, and DPR-55
Tornado and High Energy Line Break (HELB) Mitigation License Amendment Requests (LARs) - Responses to Request for Additional Information

References:

1. Letter from Dave Baxter, Site Vice President, Oconee Nuclear Station, Duke Energy Carolinas, LLC, to the U. S. Nuclear Regulatory Commission, "License Amendment Request to Revise Portions of the Updated Final Safety Analysis Report Related to the Tornado Licensing Basis," dated June 26, 2008.
2. Letter from Dave Baxter, Site Vice President, Oconee Nuclear Station, Duke Energy Carolinas, LLC, to the U. S. Nuclear Regulatory Commission, "Proposed License Amendment Request to Revise the Oconee Nuclear Station Current Licensing Basis for HELB events outside of the Containment Buildings; License Amendment Request No. 2008-005," dated June 26, 2008.
3. Letter from Dave Baxter, Site Vice President, Oconee Nuclear Station, Duke Energy Carolinas, LLC, to the U. S. Nuclear Regulatory Commission, "Proposed License Amendment Request to Revise the Oconee Nuclear Station Current Licensing Basis for HELB Events outside of the Containment Building - Unit 2; License Amendment Request No. 2008-006," dated December 22, 2008.
4. Letter from Dave Baxter, Site Vice President, Oconee Nuclear Station, Duke Energy Carolinas, LLC, to the U. S. Nuclear Regulatory Commission, "Proposed License Amendment Request to Revise the Oconee Nuclear Station Current Licensing Basis for High Energy Line Break Events Outside of the Containment Building," License Amendment Request No. 2008-007, dated June 29, 2009.

By letter dated June 26, 2008, (Ref. 1 and 2), December 22, 2008, (Ref. 3) and June 29, 2009, (Ref. 4), Duke Energy Carolinas, LLC (Duke Energy), submitted LARs for the Oconee Nuclear Station (ONS) proposing revisions to the current licensing basis regarding both HELB and tornado mitigating strategies.

Since those submittals, Duke Energy has responded to several Nuclear Regulatory Commission (NRC) requests for additional information (RAIs) regarding both proposed strategies. The NRC requested additional information by letters dated July 6, 2009, July 24, 2009, May 25, 2010, and October 8, 2010. Duke Energy provided responses to the RAIs by letters dated September 2, 2009, October 23, 2009, May 6, 2010, June 24, 2010,

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August 31, 2010, and December 7, 2010. On November 4, 2011, Duke Energy received an additional NRC RAI letter.

Enclosure 1 contains Duke Energy's responses to the RAI dated November 4, 2011. Additional time was necessary to provide supplemental information to appropriately address the following RAIs. The listed information will be provided by the indicated schedule.

- RAI 61 - Details on actions required in Mode 3 within 72 hours to transition to Mode 4, including previous licensing references - January 20, 2012.
- RAI 62 - Information regarding industry code and standard applicability to the design of the Protected Service Water (PSW) system - January 20, 2012.
- RAI 70 - Remaining design change package information as they are approved for field implementation - March 1, 2012
- RAI 76 - PSW Failure Modes and Effects Analysis/Single Failure Analysis - March 1, 2012.
- RAI 106 - Repackaging the Tornado LAR - March 31, 2012.
- RAI 107 - Technical Specifications - January 20, 2012.

Enclosure 2 contains an updated list of the tornado and HELB commitments. It should be noted that the scope of tornado commitment 17T (SSF double door modification) was modified and will be completed by December 31, 2013. Enclosure 3 contains an updated HELB LAR package that includes the Units 1, 2, and 3 HELB Report, previous responses to RAIs associated with the HELB LARs, and a complete set of drawings and figures.

If you have any questions in regard to this letter, please contact Stephen C. Newman, Regulatory Compliance Lead Engineer, Oconee Nuclear Station, at (864) 873-4388.

I declare under penalty of perjury that the foregoing is true and correct. Executed on December 16, 2011.

Sincerely,

TPGillespie

T. Preston Gillespie, Jr.
Vice President
Oconee Nuclear Station

Enclosure 1: Current RAI Responses
Enclosure 2: Updated list of current Tornado/HELB commitments
Enclosure 3: Repackaged HELB License Amendment Request

cc: (w/enclosures)

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Enclosure 1

Duke Energy RAI Responses

RAI 61

Provide a complete event sequence following a tornado and/or an HELB. In your response, provide a summary of the sequence of actions required for achieving each phase of the mitigating strategies showing how MODES of operation 3, 4, and 5 as defined in Table 1.1-1 of your Technical Specifications (TSs) will be achieved. Identify all equipment that will be available following the events to mitigate a tornado and/or an HELB. Identify all required operator actions, and when each operator action has to be completed. Identify all required repairs, and when they must be completed. For any necessary repairs provide the actions required, manpower required, and all equipment and parts that are necessary to complete the repairs. Demonstrate that the sequence of events would not result in unacceptable radiological consequences. Identify and justify the selected acceptance criteria (fission product barriers are maintained, and the spent fuel remains within the licensing basis). Provide a detailed description of the analyses performed to support the conclusions.

Duke Energy Response

HELB

All of the postulated HELBs outside containment are described in ONDS-351, Rev. 2, "Oconee Nuclear Station Units 1, 2, & 3 Analysis of Postulated High Energy Line Breaks (HELBs) Outside of Containment." The high energy systems and their postulated break locations are described in section 4.1 for Unit 1, section 5.1 for Unit 2 and section 6.1 for Unit 3. The interactions with safe shutdown equipment are described in sections 4.2 and 4.3 for Unit 1 HELBs, in sections 5.2 and 5.3 for Unit 2 HELBs and in sections 6.2 and 6.3 for Unit 3 HELBs. A summary of the consequences from the HELB interactions with safe shutdown equipment is contained in Tables 4.2-1 through 4.2-11 for Unit 1 HELBs, Tables 5.2-1 through 5.2-9 and 5.2-11 for Unit 2 HELBs, and Tables 6.2-1 through 6.2-11 for Unit 3 HELBs.

The mitigation of each HELB is dependent upon the HELB itself as well as its interactions with safe shutdown equipment. The transient response and the acceptance criteria for overcooling events (ex. Main Steam line breaks), undercooling events (ex. Main Feedwater line breaks), and excessive reactor coolant leakage (ex. Letdown line breaks) are described in section 7 of ONDS-351, Rev. 2. Section 7 did not provide a detailed listing of all required operator actions, necessary repairs, manpower requirements and the time required to perform these actions.

The tables containing the consequences of the HELB interactions were reviewed to determine if one HELB event could be found that provided the bounding event with respect to operator actions, necessary repairs, manpower requirements and the associated time limits for performing these actions. It was found that HELBs occurring inside the Turbine Building have the potential to create the most bounding scenario involving required operator actions, manpower requirements and damage repairs. Specifically, HELBs that can cause a loss of AC power to all three units coupled with failures to Condenser Circulating Water (CCW) piping resulting in Turbine Building flooding will create the bounding scenario for activities necessary to place the units in Mode 4. The postulated HELBs that create this condition are certain main feedwater line breaks on Units 1 and 2 as listed below:

- HELB 1-FDW-030-R Break 12 or 13
- HELB 2-FDW-008-R Break 6
- HELB 2-FDW-033-R Break 4 or 5
- HELB 2-FDW-035-R02 Break 4 or 5

The above breaks result in a loss of main and emergency feedwater to all three units. No unisolable breaks occur in either main steam lines for these HELB events. Therefore, the acceptance criterion for these events is based on the acceptance criterion for the loss of main feedwater event. The plant transient response for these events is described in section 7.2.1 of ONDS-351 Rev.2 with a general description of the strategy to enable a plant cooldown to cold shutdown. A more detailed description of the mitigation strategy is provided below.

The following acceptance criteria for a loss of main feedwater event ensures that the integrity of the fuel and the RCS remains unchallenged and that the event will not result in unacceptable radiological consequences:

- Peak Reactor Coolant System (RCS) pressure ≤ 2750 psig.
- Reactor Coolant Pump seal cooling restored within 20 minutes.
- Establishing and maintaining the RCS in a subcooled natural circulation condition during all phases of the mitigation strategy.

Mitigation of these postulated HELBs is divided into four distinct phases. Phase 1 is reactor shutdown and the stabilization of the affected unit(s) in Mode 3 with Reactor Coolant (RC) average temperature ≥ 525°F. Phase 2 is the plant cooldown from Mode 3 to Mode 4 (< 250°F). Phase 3 is the assessment and repair of structures, systems, and components (SSCs) required to transition the unit from Mode 4 (< 250°F) to Mode 5 (< 200°F). Phase 4 is the plant cooldown to Mode 5 (< 200°F). The following response is based on approval of the revised mitigation strategy and subsequent completion of committed modifications, and revisions to the mitigation and recovery procedures.

Refer to enclosed flowchart for overview of mitigation strategy addressed in this response.

Phase 1: Reactor Shutdown

The postulated main feedwater HELB event leads to an overheating condition for the Reactor Coolant System (RCS). The Reactor Protection System (RPS) will trip the reactor on the loss of Main Feedwater pumps or on high RCS pressure. The pressurizer code safety valves are credited to relieve pressure to maintain RCS pressure below the safety limit. The Main Steam Relief Valves (MSRVs) are the only credited means of steam release for decay heat removal during this phase.

Operator actions are needed to restore secondary side decay heat removal and reactor coolant pump (RCP) seal cooling to establish a Safe Shutdown Condition. The Standby Shutdown Facility (SSF) and the Protected Service Water (PSW) systems would remain available to establish and maintain safe shutdown for these main feedwater HELBs. Emergency procedures will direct the operators to initiate both pathways in parallel. Actions to place the SSF systems in service are contained in existing emergency procedures and are consistent with the activation of the SSF for other non-HELB events. Actions to place the PSW system (the PSW system is described in section 3.2 of ONDS-351 Rev. 2) in service will be incorporated into plant emergency procedures. The actions taken by the operators have been segregated by the different pathways in which safe shutdown would be achieved and maintained.

Pathway 1: Safe Shutdown Using PSW Systems

1. Operators in the Main Control Room (MCR) emergency start both Keowee Hydro Units (KHUs), if not already started.
2. Operators in the MCR repower the PSW electrical system from one of the two operating KHUs.
3. The control battery chargers automatically swap to the PSW source of power.
4. Operators in the MCR start the PSW pumps and open the main PSW block valve.
5. Operators in the MCR transfer power for one High Pressure Injection (HPI) pump, BWST suction valve (HP-24), HPI header injection valve (HP-26) and the RCS vent valves (RC-155 through RC-160) on each unit from their normal source of power to the PSW power.
6. Operators in the MCR begin feeding each unit's SGs. This activity must be completed within 15 minutes of the loss of main and emergency feedwater.
7. Operators in the MCR reestablish RCP seal cooling by opening HP-24, closing the RCP seal flow control outlet valve (HP-139), starting the HPI pump, and throttling open RCP seal flow control bypass valve (HP-140). This activity must be completed within 20 minutes.
8. Operators in the MCR open RCS vent valves to establish letdown as required to maintain pressurizer level.
9. Operators are dispatched to the East Penetration Room (EPR) to transfer power for selected pressurizer heaters from their normal source of power to the PSW power.
10. Operators in the MCR energize selected pressurizer heaters as necessary to maintain RCS pressure at approximately 2155 psig.

Pathway 2: Safe Shutdown Using SSF Systems

1. Operators are dispatched to the SSF upon recognition of the loss of RCP seal cooling.
2. One operator at the SSF performs breaker transfers for the 600VAC Motor Control Centers (1XSF, 2XSF, and 3XSF)
3. One operator in the SSF Control Room (SSFCR) emergency starts the SSF diesel-generator, starts the diesel engine service water pump, and starts the SSF Auxiliary Service Water (SSF ASW) pump
4. Operators in the SSFCR contact operators in the MCR to determine if actions to place PSW systems in service have been successful.
5. If actions to place PSW in service have been successful, then operators at the SSF would standby awaiting further instructions.
6. If actions to place PSW in service were not successful, then operators at the SSF would continue performing actions as directed by the SSF emergency operating procedure.
7. Operators in the SSFCR start the SSF RC Makeup pump to establish RCP seal cooling as well as RC makeup. This action must be completed within 20 minutes following a loss of all RCP seal cooling.
8. Operators in the SSFCR isolate possible RCS leakage pathways (RC letdown and RCP seal return).
9. Operators in the SSFCR begin feeding the steam generators at a rate necessary to control RCS temperature and pressure. This action must be completed within 14 minutes.
10. Operators in the SSFCR energize pressurizer heaters, when conditions permit, to maintain RCS pressure at approximately 2150 psig.
11. An operator is dispatched to divert the SSF Diesel Service Water discharge to the yard drain after the diesel-generator has been operating for 1 hour and 45 minutes. This action

must be completed between 1 hour and 45 minutes and 2 hours following the emergency start of the SSF Diesel Generator.

While the operators are placing the affected unit(s) in Mode 3 with an RC temperature of ≥ 525° F, the Operations Shift Manager initiates the Emergency Plan, and activates the Technical Support Center (TSC) and the Operations Support Center (OSC). Implementation procedure RP/1000/025 directs the OSC to initiate the site coordinating procedure for assessment and damage repair, RP/1000/022. RP/1000/022, in turn, directs Operations and Engineering personnel to assess and identify credited SSCs that are in need of repair.

The postulated main feedwater HELBs (listed above) can result in pipe breaches to the CCW piping. The breaches in CCW piping can create flooding inside the Turbine Building. The source of flooding inside the Turbine Building would need to be isolated. If CCW inlet siphon and gravity flow has been lost, no isolation of the CCW inlet piping would be required to terminate flooding from the CCW intake piping. If lake elevation is below the point needed for gravity induced reverse flow, no isolation of the CCW discharge piping would be required. It is assumed that lake elevation is sufficiently high for gravity induced flow to both CCW inlet and discharge piping in order to maximize the actions needed to terminate TB flooding.

Operators would be dispatched to close the CCW pump discharge valves on each unit at the intake structure to isolate Turbine Building flooding inputs from the CCW inlet because power has been lost. Maintenance would be dispatched to lower the CCW discharge gates to isolate Turbine Building flooding inputs from the CCW discharge. Once the flooding inputs to the Turbine Building have been isolated, the flood waters will gravity drain through the drain located at the south end of the Turbine Building basement.

Operators would begin monitoring the water temperature and water level in the Spent Fuel Pool (SFP) due to the loss of spent fuel cooling as directed by existing emergency procedures. Refill of the SFP is performed using existing site recovery procedures and existing onsite and offsite personnel and resources that provide redundant and diverse methods to refill the SFPs. This is an existing time critical action (TCA) documented in OSS-0254.00-00-4005, Design Basis Specification for the Design Basis Events, Rev. 22, which must be completed no later than 36 hours following start of the SSF RCMU Pump. The acceptance criteria for this activity is that the boron concentration in the SFP is maintained above that required to result in a $K_{eff} \leq 0.95$ and water level is maintained above the fuel to ensure that the integrity of the fuel remains unchallenged and that there are no unacceptable radiological consequences.

A Safe Shutdown condition can be maintained from either the Main Control Room using the PSW and HPI Systems or from the SSF Control Room using the SSF ASW and SSF RCMU Systems. The SSF has an established mission time of 72 hours. There are no required repairs from these postulated HELBs to achieve safe shutdown using either the PSW or SSF systems. However, if makeup to the CCW piping from the CCW intake or discharge via gravity induced flow is not available, a portable pump would need to be installed at the CCW intake to provide replenishment of the water being used by the PSW or SSF systems. Electrical power can be supplied from either the PSW electrical system or the SSF electrical system. The actual required time for installing the portable pump varies with lake level, CCW piping break size and location, and CCW inlet high point air in-leakage. A time critical action (TCA) has been applied to the deployment and placing of the portable pump in operation within 3 hours and 20 minutes of a loss of forced and gravity CCW system flow. This is an existing TCA documented in OSS-0254.00-00-4005, Design Basis Specification for the Design Basis Events, Rev. 22.

Phase 2: Plant Cooldown to Mode 4 (< 250°F)

A plant cooldown is initiated within 72 hours of event initiation.

Plant cooldown requires one HPI pump to provide sufficient makeup capability. No damage repairs are needed to perform a plant cooldown to Mode 4. Power is supplied to the HPI pump and the HPI motor operated valves from the PSW electrical system which is not damaged by the HELBs. Cooling water to the HPI pump is provided by the PSW booster pump. Either the PSW System or the SSF ASW System could be used to feed the steam generators to enable a plant cooldown. Since the RCPs have been lost due to the loss of power, a natural circulation cooldown would be required. Any time a natural circulation cooldown is initiated, the Reactor Vessel (RV) Head Vents are required to be opened. Power to operate the RV Head Vents is provided from the PSW electrical system. The RCS is depressurized during plant cooldown by turning the pressurizer heaters off and cycling the Pressurizer Power Operated Relief Valve (PORV) (RC-66). Power to the PORV is supplied from the battery backed buses which will continue to receive power from the battery chargers via the PSW electrical system. Several motor-operated valves would need to be repositioned during the plant cooldown. The Portable Valve Control Panel (PVCP) would be installed to restore power to the decay heat drop line isolation valves (LP-1 and LP-2), and the Core Flood Tank (CFT) outlet valves (CF-1 and CF-2) on each unit since their normal power sources would be lost. The PVCP would be installed in the yard adjacent to each unit's West Penetration Room (WPR). Cables would be pulled from the SSF to the PVCP and connections made at the SSF and the PVCP. Cables would also be pulled from the PVCP to LP-1, LP-2, CF-1, and CF-2 valve electrical penetrations located in the WPR. Connections would be made at the PVCP and at the electrical penetrations for the valves. These activities are completed by Oconee craft personnel with staff augmentation using existing station procedures. Additional personnel would be assembled in accordance with the station emergency plan at the site within 8 hours to begin restoration of power to LP-1, LP-2, CF-1 and CF-2. The estimated time to install the PVCP and repower the valves is an additional 21 hours. Plant cooldown to Mode 4 (< 250°F) would be performed when the valves have been repowered.

Plant Cooldown Sequence to Mode 4:

1. Operators in the MCR start the PSW pumps (if not already operating).
2. Operators in the MCR begin feeding each unit's SGs with PSW (if not already in progress) to maintain SG water levels at or above the levels needed to maintain natural circulation.
3. Operators in the SSFCR would isolate SSF ASW feed to the SGs (if feeding).
4. Operators in the MCR would align HPI pump suction to the BWST and start one HPI pump (if not already operating).
5. Operators in the MCR throttle HP-140 as necessary to maintain RCP seal cooling.
6. Operators at the SSFCR would stop the SSF RCMU Pump (if operating) and isolate the RCS letdown to the Spent Fuel Pool (if open).
7. Operators in the MCR open the RV head vent valves (if not already open for pressurizer level control).
8. Operators in the MCR throttle open the Power-Operated Atmospheric Dump Valves (POADVs) to establish a natural circulation RCS cool down.
9. Operators in the MCR throttle the PSW flow control valves to each SG as necessary to maintain SG water level at the desired level.
10. If additional RCS makeup is needed during plant cooldown, operators in the MCR would throttle open HP-26 as necessary to maintain pressurizer level.
11. Operators at the SSFCR would isolate the RCS letdown to the Spent Fuel Pool (if open).

12. Operators at the SSF would turn off the pressurizer heaters controlled from the SSF.
13. Operators in the MCR turn off the pressurizer heaters controlled from the MCR.
14. Operators in the MCR cycle the Pressurizer PORV to decrease RCS pressure as required to maintain the required RC subcooling margin during plant cooldown.
15. When RCS pressure is approximately 700 psig, the Core Flood Tank Isolation Valves (CF-1 and CF-2) are closed from the PVCP.
16. Operators would be dispatched to throttle open the manually operated ADVs during the latter stages of cooldown to complete the RCS cooldown to Mode 4 (< 250°F).
17. Operators in the MCR would stabilize RCS pressure at approximately 300 psig by energizing pressurizer heaters with RCS temperature < 250°F.
18. At the conclusion of the cooldown, the manually operated ADVs are expected to be fully open with RCS temperature between 212°F and 250°F. Operators would no longer be needed at the ADVs.
19. Operators in the MCR close the RV head vent valves.
20. Operators in the MCR stop the operating HPI Pumps.

In this configuration long term subcooled natural circulation decay heat removal conditions are maintained with RC pressure being controlled by the cycling of the pressurizer heaters and RC temperature being maintained < 250°F by maintaining water level in the SGs at or above the levels needed for natural circulation.

Phase 3: Damage Assessment and Repairs Required to Achieve Mode 5 (< 200°F)

HELB damage assessment is initiated to assess and repair systems needed to allow plant cooldown from Mode 4 (< 250°F) to Mode 5 (< 200°F). Although the assessment may begin in Phase 1, the systems needed to achieve cold shutdown are not required to be repaired prior to initiating a cooldown of the RCS to Mode 4 (< 250°F). The scope of the assessment determines the availability of the CCW system, the Low Pressure Service Water (LPSW) system, the Low Pressure Injection (LPI) system, and the associated electrical power to these systems.

The postulated loss of AC power to all three units would require restoring power to one CCW pump motor, two LPSW pump motors (one shared by Units 1 & 2, and one for Unit 3), and three LPI pump motors (one for each unit). The actions taken to restore power to the pump motors needed for cold shutdown rely on the current Appendix R strategy, procedures and equipment. The necessary electrical equipment has been identified in procedures used for Appendix R and would be available to enable the restoration of power to these motors. The manpower requirements to execute the repairs have been defined in the procedures used for Appendix R. In addition, two LPSW pump motors would need to be replaced due to the effects of Turbine Building Flooding. There are two spare LPSW pump motors that can be installed using existing station procedures. The manpower requirements to execute the repairs have been defined in the procedures used for Appendix R.

The listed HELBs that create the bounding scenario for activities necessary to place the units in Mode 4 (< 250°F), may not establish the bounding time for repairs needed to achieve Mode 5 (< 200°F). HELBs resulting in damage to CCW and LPSW piping systems required for cold shutdown are described in Duke Energy's response to RAI 102. The HELBs identified in that response are expected to create the bounding time for damage repairs needed to proceed to a cold shutdown condition. The postulated line breaks in the CCW and LPSW systems would need to be isolated or repaired as necessary to restore one unit's CCW system to operation, and the

LPSW flow paths for the LPI coolers (supply and return headers). The level of effort and the duration to complete piping repairs have not been defined in existing station procedures.

While the units are being maintained in a long term subcooled natural circulation decay heat removal condition, the repairs and system alignments necessary to transition the units from Mode 4 (< 250°F) with decay heat removal via the SGs to Mode 5 (< 200°F) would be completed. The Oconee Emergency Response organization would coordinate these recovery actions augmented by fleet and industry personnel. Duke Energy would obtain materials and resources needed to restore the systems needed to achieve Mode 5, utilizing existing fleet resources and existing relationships with other utilities, suppliers, and manufacturers.

Phase 4: Plant Cooldown to Mode 5 (< 200°F)

When the damage repairs for the CCW and LPSW systems, as well as the system alignments for the CCW, LPSW, and LPI systems have been completed, a plant cooldown would be initiated from Mode 4 to Mode 5.

Plant Cooldown Sequence to Mode 5:

1. Operators would verify at least two condenser outlet valves are open on the unit in which the CCW system would be placed into service. If none are open, maintenance would be contacted to open two condenser outlet valves.
2. An operator would be dispatched to the CCW intake structure to throttle open the discharge valve on the CCW pump to be started.
3. An operator would locally start the one CCW pump at the trailer-mounted (Appendix R) 4160V switchgear.
4. The operator at the CCW intake structure would then fully open the discharge valve on the running CCW pump.
5. Operators would be dispatched to the Turbine Building basement to close the discharge valves on the LPSW pumps to be started. One pump shared by Units 1 and 2 and one pump for Unit 3 would be needed for cooldown to Mode 5.
6. An operator would locally start the desired LPSW pumps at the trailer-mounted (Appendix R) 4160V switchgear.
7. Operators would slowly throttle open the discharge valve on the running LPSW pumps to fill the LPSW system. Eventually, the LPSW pump discharge valves will be fully opened.
8. Operators open LP-1 and LP-2 at the PVCP.
9. An operator would locally start one LPI pump on each unit at the trailer-mounted (Appendix R) 4160V switchgear.
10. Communications would be established between the operators in the MCR and the operators at the LPI cooler outlet LPSW block valve. The LPSW outlet block would be locally throttled open to establish a cooldown to < 200°F.

<u>Tornado</u>

Mitigation of a tornado strike is divided into five distinct phases. Phase 1 is reactor shutdown and the stabilization of the affected unit(s) in Mode 3 with Reactor Coolant (RC) average temperature ≥ 525°F. Phase 2 is the assessment and repair of SSCs required to transition the unit from Mode 3 to Mode 4. Phase 3 is the plant cooldown from Mode 3 to Mode 4 (< 250°F). Phase 4 is the assessment and repair of structures, systems, and components (SSCs) required to transition the unit from Mode 4 (< 250°F) to Mode 5 (< 200°F). Phase 5 is the plant cooldown to Mode 5 (< 200°F).

The following acceptance criteria for a tornado event ensures that the integrity of the fuel and the RCS remains unchallenged and that the event will not result in unacceptable radiological consequences:

- Peak Reactor Coolant System (RCS) pressure ≤ 2750 psig.
- Reactor Coolant Pump seal cooling restored within 20 minutes
- Establishing and maintaining the RCS in a subcooled natural circulation condition during all phases of the mitigation strategy

The tornado mitigation strategy relies on the strategy, procedures and equipment originally developed to meet the Appendix R license basis with the following exceptions:

- Tornado damage to SSCs needed to transition the affected unit(s) from Mode 3 to Mode 4 and from Mode 4 to Mode 5 will need to be repaired.

- The PSW booster pump is used to provide cooling water to the high pressure injection pump (Appendix R strategy relies upon replacement air cooled motors).

- 4KV PSW power supplies the high pressure injection pump (Appendix R strategy relies upon trailed mounted 4KV switchgear as power source).

The following response is based on the committed modifications being implemented and supersedes responses provided in previously submitted RAI responses due to the change in proposed mitigation strategy. The following response is also based on the proposed revisions to current recovery procedures needed to address repairing tornado damage being implemented.

Refer to enclosed flowchart for overview of mitigation strategy addressed in this response.

Phase 1

Overview

Phase 1 of the event mitigation is the stabilization of the affected unit(s) in hot standby conditions with an RC temperature of ≥ 525° F from the Standby Shutdown Facility (SSF). The SSF Reactor Coolant Makeup (RCMU) Pump, taking suction from the Spent Fuel Pool, maintains the reactor subcritical, maintains adequate RC inventory control and provides reactor coolant pump (RCP) seal cooling. RC pressure is maintained by Pressurizer heaters powered and controlled from the SSF. The SSF Auxiliary Service Water (ASW) Pump, taking suction from the Unit 2 Condenser Circulating Water (CCW) System intake piping, feeds the steam generators to provide SG decay heat removal. Main Steam (MS) pressure is regulated using MS isolation and steam release through the main steam relief valves. The inventory in the Unit 2 CCW intake piping is replenished by gravity induced flow of Lake Keowee directly into the Unit 2 CCW intake piping and gravity induced flow of Lake Keowee indirectly into the Unit 2 CCW intake piping via the CCW discharge piping. An SSF portable pump is deployed and placed into the CCW intake canal following start of the SSF diesel generator but is not immediately placed in operation unless necessary. In the event that gravity flow is interrupted, the discharge hose of the SSF portable pump is aligned to fill the Unit 2 CCW intake piping and the pump is started to maintain inventory in the Unit 2 CCW intake piping for supplying the SSF ASW pump. The SSF ASW Pump, RCMU Pump, HVAC System, SSF portable pump and associated electrical systems are powered from the SSF diesel generator.

Event Sequence

The operating crew is notified of a tornado watch or tornado warning via the weather radio located in the Unit 1 & 2 MCR. Notification of a tornado watch or warning is an entry condition into abnormal operation procedure AP/0/A/1700/006, Natural Disaster. When a tornado warning is in effect AP/06 will direct the operating crew to dispatch one licensed operator and one non-licensed operator to the SSF control room.

Depending upon the severity of the damage when the tornado strikes the station, the reactor(s) may be manually tripped or may automatically trip. If a tornado missile breaches the pressure boundary of steam piping, the Main Steam Isolation Valves (MSIVs) will close and isolate the breach before overcooling of the RCS can occur.

The operating crew on each affected unit will respond to the reactor trip by performing procedure EP/1800/001, Emergency Operating Procedure. The EOP provides guidance to ensure that the reactor and turbine are tripped, and to verify that reactor coolant pump seal cooling is available, that the reactor remains subcritical, that adequate RCS inventory is being provided and that the appropriate amount of steam generator (SG) cooling is being provided. During performance of the immediate manual actions of the EOP the operating crew determines if a loss of RCP seal cooling and SG cooling has occurred and directs the SSF operator to establish RCP seal cooling and SG feed from the SSF.

When directed by the MCR, the operators stationed at the SSF takes the following actions to re-establish RCP seal cooling and SG DHR using AP/1700/025, SSF Emergency Operating Procedure:

1. The non-licensed operator performs breaker transfers for the 600VAC Motor Control Centers (1XSF, 2XSF, and/or 3XSF) in the HVAC room of the SSF to transfer control of the RCS boundary isolation valves, wide range core inlet temperature instruments and pressurizer heaters from the MCR of the affected unit(s) to the SSF control room

2. The licensed operator in the SSF control room emergency starts the SSF diesel-generator, starts the diesel engine service water pump and starts the SSF Auxiliary Service Water (ASW) pump.

3. The licensed operator starts the SSF Reactor Coolant Makeup (RCMU) Pump for each affected unit in the override mode. When started in the override mode, the pump suction and discharge flow paths are automatically aligned and the RCMU pump then automatically starts to provide RCP seal cooling. Restoration of RCP seal cooling is an existing time critical action (TCA) documented in OSS-0254.00-00-4005, Design Basis Specification for the Design Basis Events, Rev. 22, which must be completed within 20 minutes of a loss of seal cooling.

4. The licensed operator aligns SSF ASW to each affected unit with the exception of the SSF ASW header flow regulating valve which will remain closed

5. The licensed operator establishes ASW flow to one of the affected unit's SGs by throttling open the unit's SSF ASW header flow control valve. Restoration of SG feed from the SSF is an existing TCA documented in OSS-0254.00-00-4005, Design Basis Specification for

the Design Basis Events, Rev. 22, which must be completed within 14 minutes of a loss of SG cooling and RCP seal cooling.

While the operator stationed at the SSF is placing the SSF in operation, additional licensed operators are dispatched to the SSF from the MCR of any other affected unit. Three available exits from the Auxiliary Building to the SSF and two entrances into the SSF provides reasonable assurance that the additional licensed operators can access the SSF control room and establish SSF ASW flow within 14 minutes. Walkdowns demonstrate that an operator can travel from each of the MCRs, exit the Auxiliary Building through any of the three available exits after first determining that the other two are blocked, enter the SSF through the most distant entrance and establish auxiliary service water flow within 14 minutes.

Upon arriving in the SSF control room these additional licensed operators establish feed to the SGs on the remaining affected units by throttling open the closed flow regulating valve. The licensed operators in the SSF control room then isolate possible RCS leakage pathways (RC letdown and RCP seal return) and energize pressurizer heaters, when conditions permit, to maintain RCS pressure at approximately 2150 psig.

The Maintenance Department is notified to deploy the SSF portable pump and prepare it for operation per AP/1700/25. If the gravity flow paths used to replenish the Unit 2 CCW intake piping are unavailable, the discharge piping of the SSF portable pump is aligned to the Unit 2 CCW intake piping and the pump is placed in operation. The deployment and placing of the SSF portable pump in operation is an existing TCA documented in OSS-0254.00-00-4005, Design Basis Specification for the Design Basis Events, Rev. 22, which must be completed within 3 hours and 20 minutes of a loss of forced and gravity Condenser Circulating Water (CCW) system flow.

One hour and forty five minutes after the SSF diesel generator is started the non-licensed operator locally diverts the discharge from the diesel generator heat exchangers to the yard drains per AP/25. This is an existing TCA documented in OSS-0254.00-00-4005, Design Basis Specification for the Design Basis Events, Rev. 22, which must be completed between one hour forty five minutes and two hours following the start of the SSF diesel generator.

The licensed operators stationed at the SSF maintain the affected unit(s) in hot standby subcooled natural circulation conditions with an RC temperature of ≥ 525° F for up to 72 hours while the assessment and repair of components credited for the transition of the units from Mode 3 to Mode 4 are completed.

While the operators at the SSF are placing the affected unit(s) in Mode 3 with an RC temperature of ≥ 525° F, the Operations Shift Manager initiates the Emergency Plan, and activates the Technical Support Center (TSC) and the Operations Support Center (OSC). Implementation procedure RP/1000/025 directs the OSC to initiate the site coordinating procedure for assessment and damage repair, RP/1000/022. RP/1000/022, in turn, directs Operations and Engineering personnel to assess and identify credited SSCs that are in need of repair.

Phase 2

Local operation of a train of High Pressure Injection (HPI) including RCP seal cooling, local operation of the Protected Service Water (PSW) booster pump, local operation of the tornado protected MS Atmospheric Dump Valves (ADVs) and SG cooling via the SSF ASW System is credited for transitioning the affected unit(s) from Mode 3 to Mode 4. In addition, operation of the reactor vessel head vent valves, Pressurizer (PZR) PORV and the core flood tank isolation valves via a portable valve control panel is required.

Phase 2 of the event mitigation consists of performing assessments, repairs and alignment of these SSCs. These assessment and repair activities are completed within 72 hours of event initiation.

Event Sequence

The assessment, repair and alignment activities consist of:

1. Assessing the availability of power to the Protected Service Water (PSW) Building from either a Keowee Hydro Unit or the PSW substation. If neither source of power is available, the 13.8KV transmission line from the PSW substation to the PSW building will be restored to service and any faults on the 100KV line to the PSW substation will be isolated. These repairs will be completed using readily available commercial resources and personnel from the fleet transmission organization.

2. Manually restoring the PSW building electrical systems and ventilation systems. This activity is completed following restoration of 13.8KV power to the PSW building using site damage repair procedures, personnel and resources.

3. Configuring the PSW booster pump motor for local start. The PSW pump, motor. 4KV breaker, control power, cabling, and piping are tornado protected. This activity is completed using site damage repair procedures, personnel and resources.

4. Configuring the High Pressure Injection (HPI) pump motor for local start. The HPI pump, motor, 4KV breaker, control power, cabling, pump suction piping and pump discharge piping below ground elevation is tornado protected. This activity is completed using site damage repair procedures, personnel and resources.

5. Assessing and replacing damaged HPI discharge piping, including seal injection piping, located above grade in the East and West Penetration Rooms. This activity is completed using site damage repair procedures, personnel and resources.

6. Installing the existing Appendix R Portable Valve Control Panel (PVCP) in the yard adjacent to each affected unit(s) West Penetration Room, pulling 600V power cables and 120V control cables from the SSF to the PVCP and making associated connections and pulling 600 V power cables and 120V control cables from the PVCP to the reactor head vent valves (RC-159/RC-160), the Pressurizer PORV (RC-66), the Core Flood Tank Isolation Valves (CF-1/CF-2) the LPI Return Block from RCS Valves (LP-1/LP-2) penetrations located in the Penetration Rooms, and making associated connections. This activity is completed using existing procedures.

7. Aligning power to the SSF from the PSW 4kV switchgear and shutting down the SSF D/G. This activity is completed by Operations personnel from the SSF control room.

8. Initiate monitoring the water temperature and water level in the Spent Fuel Pool (SFP) due to the loss of spent fuel cooling as directed by existing emergency procedures. Refill of the SFP is performed using existing site recovery procedures and existing onsite and

offsite personnel and resources that provide redundant and diverse methods to refill the SFPs. This is an existing time critical action (TCA) documented in OSS-0254.00-00-4005, Design Basis Specification for the Design Basis Events, Rev. 22, which must be completed no later than 36 hours following start of the SSF RCMU Pump. The acceptance criteria for this activity is that the boron concentration in the SFP is maintained above that required to result in a $K_{eff} \leq 0.95$ and water level is maintained above the fuel to ensure that the integrity of the fuel remains unchallenged and that there are no unacceptable radiological consequences.

Note: A detailed description of the man power, equipment and parts required to complete the repair activities described above will be provided by January 20, 2012.

Phase 3

Overview

Phase 3 of event mitigation consists of a cooldown of the affected unit(s) from Mode 3 to Mode 4 (< 250°F) by performing a subcooled natural circulation cool down. Local operation of the PSW booster pump provides cooling water to the High Pressure Injection Pump. Local operation of the PSW powered HPI Pump taking suction from the Borated Water Storage Tank maintains the reactor subcritical, maintains adequate RC inventory control and provides reactor coolant pump seal cooling. Remote operation of the SSF Auxiliary Service Water (ASW) Pump taking suction from the Unit 2 Condenser Circulating Water (CCW) System intake piping feeds the steam generators to provide SG decay heat removal. MS pressure and flow is regulated during cool down by local operation of tornado protected ADVs. Gravity induced CCW flow or the SSF portable pump maintains inventory in the CCW system for supplying the SSF ASW pump. The SSF ASW Pump, HVAC system, portable pump and associated electrical systems are powered from the SSF via the PSW Power System.

Phase 3 is initiated within 72 hours of event initiation.

Event Sequence

Cooldown of the affected unit(s) from Mode 3 to Mode 4 is performed by Operations personnel using OP/0/A/1102/025, Cooldown Following Major Site Damage

These activities consist of:

1. Locally starting the PSW booster pump to provide cooling water to the HPI Pump
2. Aligning HPI Pump suction from BWST and locally starting an HPI Pump on each affected unit
3. Locally throttling open the RCP seal injection total flow control valve to establish RCP seal cooling
4. Securing the SSF RCMU Pump from the SSF control room
5. Locally opening the reactor head vent valves from the PVCP

6. Locally throttling open the ADVs to establish a natural circulation RCS cool down.

7. Throttling the SSF ASW flow control valves from the SSF control room to each SG as necessary to maintain SG level at the desired level during plant cooldown.

8. Locally throttling open RC makeup valve as necessary to maintain Pressurizer at desired level during plant cooldown.

9. Isolating RC letdown to the Spent Fuel Pool from the SSF control room

10. Securing the Pressurizer heaters from the SSF control room

11. Locally cycling the Pressurizer PORV from the PVCP to decrease RCS pressure.

12. Locally closing the Core Flood Tank Isolation Valves (CF-1/CF-2) from the PVCP when RCS pressure is approximately 700 psig.

13. RCS pressure is stabilized at approximately 300 psig and RCS temperature is stabilized at less than 250 deg. F (Mode 4).

14. The reactor head vent valves are closed from the PVCP and the HPI Pump is secured locally.

In this configuration long term subcooled natural circulation decay heat removal conditions are maintained with RC pressure being controlled by the cycling of PZR heaters from the SSF and RC temperature being maintained < 250° F by the feeding and steaming of the SGs.

Phase 4: Damage Assessment and Repairs required to achieve Mode 5 (< 200°F)

While the affected unit(s) are being maintained in a long term subcooled natural circulation decay heat removal condition a tornado damage assessment will be initiated to assess and repair systems needed to allow plant cooldown from Mode 4 (< 250°F) to Mode 5 (< 200°F). Although the assessment may begin in Phase 1, the systems needed to achieve cold shutdown are not required to be repaired prior to initiating a cooldown of the RCS to Mode 4 (< 250°F). The scope of the assessment determines the availability of the CCW system, the Low Pressure Service Water (LPSW) system, the Low Pressure Injection (LPI) system, and the associated electrical power to these systems.

The existing procedures originally developed to meet the Appendix R license basis provide the bases for these tornado mitigation assessments, repairs and system alignments. In addition, damage to piping on the SSCs needed to achieve Mode 5 will need to be repaired.

The Oconee Emergency Response organization will coordinate these recovery actions augmented by fleet and industry personnel. Duke Energy would obtain materials and resources needed to restore the systems needed to achieve Mode 5, utilizing existing fleet resources and existing relationships with other utilities, suppliers, and manufacturers.

The timeline and resource requirements for repair of equipment is unknown due to the unpredictable scope of damage that may occur to SSCs needed to establish cooling via the Low Pressure Injection System.

Phase 5: Plant Cooldown to Mode 5 (< 200°F)

When damage repair and system alignments have been completed for the CCW, LPSW and LPI systems, a plant cooldown is initiated from Mode 4 to Mode 5.

Plant Cooldown Sequence to Mode 5:

1. Operators verify at least two condenser outlet valves are open on the unit in which the CCW system would be placed into service. If none are open, maintenance personnel are contacted to open two condenser outlet valves.

2. An operator is dispatched to the CCW intake structure to throttle open the discharge valve on the CCW pump to be started.

3. An operator locally starts the one CCW pump.

4. The operator at the CCW intake structure fully opens the discharge valve on the running CCW pump.

5. Operators locally close the discharge valves on the LPSW pumps to be started. One pump shared by Units 1 and 2 and one pump for Unit 3 is needed for cooldown to Mode 5.

6. An operator locally starts the desired LPSW pumps.

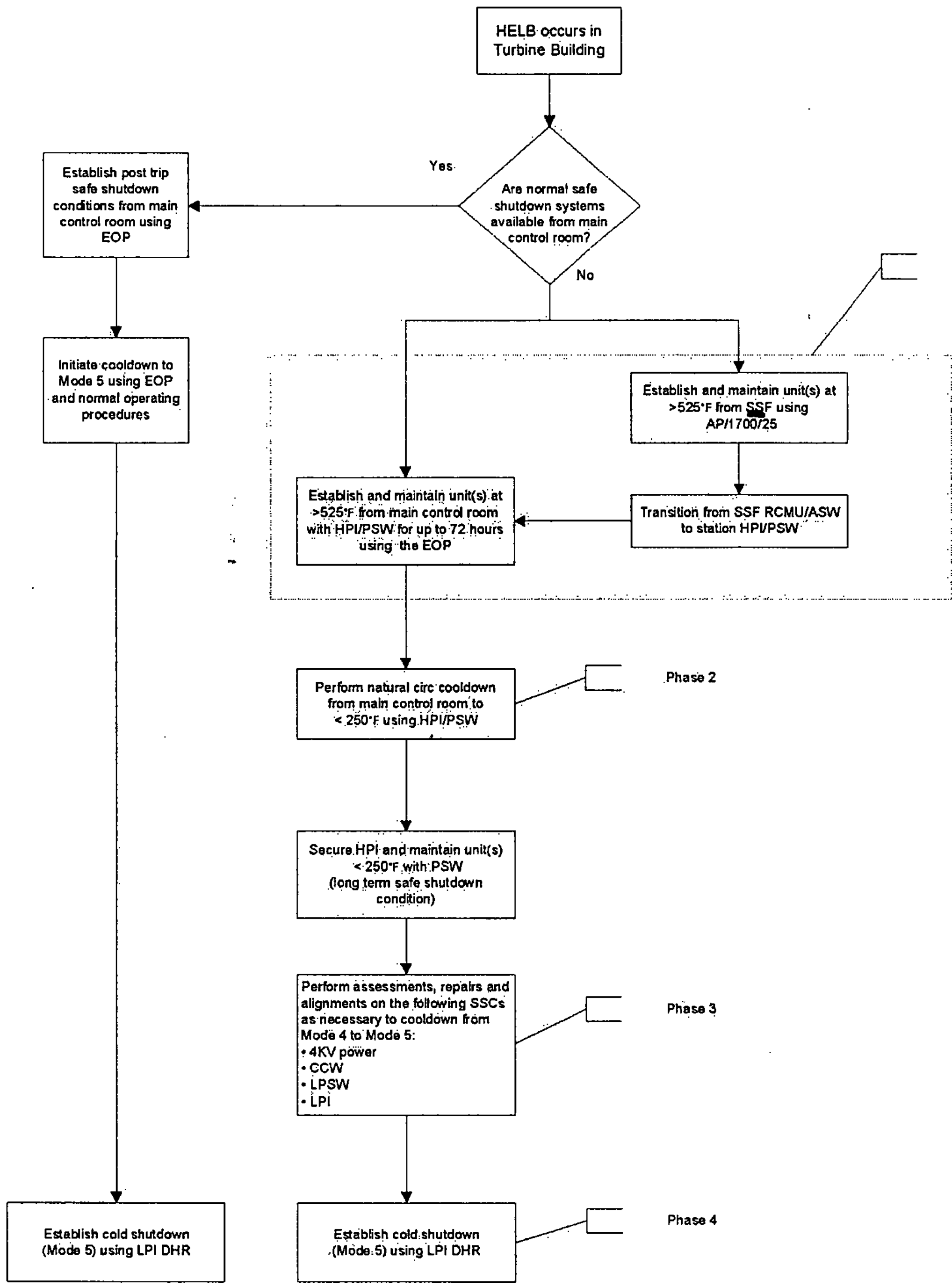
7. Operators slowly throttle open the discharge valve on the running LPSW pumps to fill the LPSW system.

8. Operators locally open LP-1 and LP-2 at the PVCP.

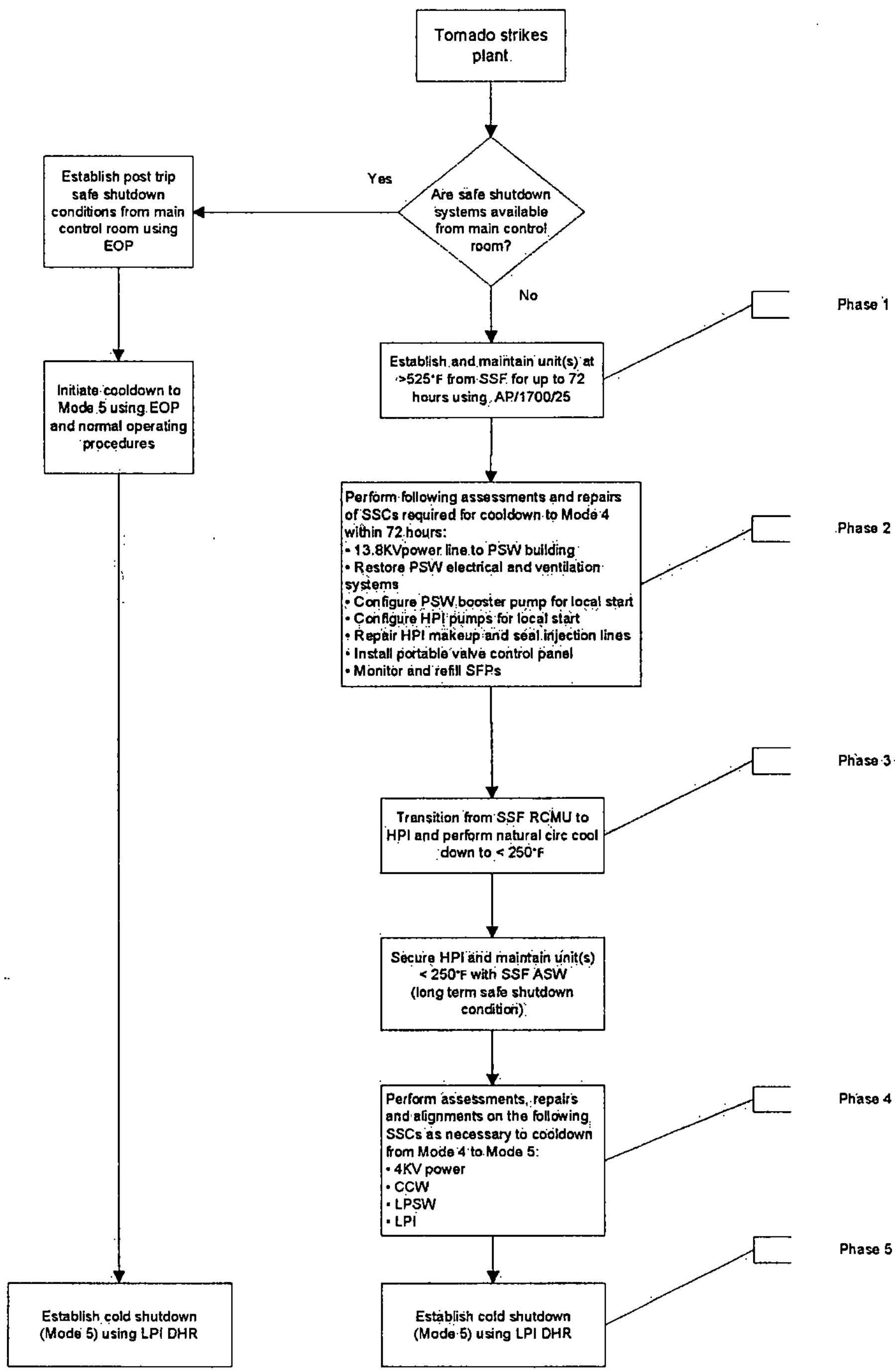
9. An operator locally starts one LPI pump on each unit.

10. An operator locally throttles open the LPI cooler outlet LPSW block valve to establish a cooldown to < 200°F.

RAI 61 HELB Event Overview



RAI 61 Tornado Event Overview



RAI 62

Provide a complete list of all modifications, design packages and supporting calculations which require prior NRC review and approval prior to changing the UFSAR associated with the LARs. In addition provide an executive summary for each calculation. The summary should include initial conditions, all assumptions, analyses performed, acceptance criteria, and a justification for the conclusion reached.

Duke Energy Response

There are two modifications that need NRC approval associated with the tornado and HELB license amendments. They are the Main Steam Isolation Valve (MSIV) modification and the Protected Service Water (PSW) system modification.

Design of the MSIV modification is in progress and submittal of a separate license amendment request addressing MSIV installation is planned to occur in 2013. The tornado and HELB license amendment requests commit to and rely on the MSIV modification. These license amendment requests do not include the necessary information to support licensing the MSIVs.

The PSW modification requires NRC review and approval. Some PSW related design change packages have been implemented using 10CFR 50.59 as listed in the table given later in this response. The scope of the PSW modification within these design change packages does not require NRC review and approval.

Summary of Protected Service Water Modification Response Contents

During a conference call with members of the NRC Staff on November 21, 2011, Duke Energy outlined the proposed structure of the response to this RAI. The proposed response structure was considered acceptable. In order to provide the information in the most efficient means possible, the Duke Energy response includes the following:

1. A System Description of the Protected Service Water System.

2. A discussion of the design of the Protected Service Water System and the application of industry codes and standards to the design.

3. Simplified mechanical, electrical, and civil drawings that illustrate the individual design packages that constitute the PSW modification.

4. Final Scope Documents for Design Change Packages that have been released to the field for implementation.

5. A list of calculations developed in support of, or impacted, and revised by the design changes identified in item 4, arranged by design change package. Copies of the associated, completed calculations are also included.

Item 1 is included in this response.

Item 2 will be provided by January 20, 2012.

Items 3, 4, and 5 have been made available electronically to the NRC Staff for audit, or will be made available as the design change packages are issued for field implementation. All information is scheduled to be available for NRC Staff audit no later than March 2, 2012.

Protected Service Water System Description

The Protected Service Water (PSW) system is designed as a standby system for use under emergency conditions. The PSW System includes a dedicated power system. The PSW System provides added "defense-in-depth" protection by serving as a backup to existing safety systems and as such, the system is not required to comply with single failure criteria. The PSW system is provided as an alternate means to achieve and maintain a stable RCS pressure and temperature for one, two, or three units following postulated event scenarios that result in the loss of 4160V essential power.

The PSW System is also capable of cooling the RCS to 250 °F and maintaining this condition until damage repairs can be implemented to proceed to cold shutdown. Failures in the PSW system will not cause failures or inadvertent operations in existing plant systems. The PSW system is fully controllable from the main control rooms and will be activated when existing redundant emergency systems are not available.

The PSW System can maintain these conditions for all three units for an extended period of operation during which time other plant systems required to cool down to Mode 5 conditions will be restored and brought into service as required.

The mechanical portion of the PSW system is designed to provide decay heat removal by feeding Keowee Lake water to the secondary side of the steam generators. The system, consisting of one booster pump, one high head pump and a portable pump, shall be capable of providing 375 gpm per unit at 1082 psig within 15 minutes following the initiating event. In addition, the system is designed to supply Keowee Lake water at 10 gpm per unit to the HPI pump motor coolers.

The PSW system utilizes the inventory of lake water contained in the plant Unit 2 Condenser Circulating Water (CCW) embedded piping. The PSW pumps are located in the Auxiliary Building at Elev.771' (except the portable pump) and take suction from the Unit 2 CCW embedded piping and discharge into the steam generators of each unit via separate lines into the emergency feedwater headers. The raw water is vaporized in the steam generator removing residual heat and is dumped to atmosphere. The Unit 2 CCW embedded piping is interconnected with Units 1 & 3. For extended operation, the PSW portable pump with a flow path capable of taking suction from the intake canal and discharging into the Unit 2 CCW line, is designed to provide a backup supply of water to the PSW system in the event of loss of CCW and subsequent loss of CCW siphon flow. The PSW portable pump is installed manually according to procedures.

The piping system has pump minimum flow lines that discharge back into the Unit 2 CCW embedded piping. For flow testing to the steam generators, the system is connected to a condensate water source located in the Turbine Building that is normally isolated using valves in the Auxiliary Building.

The PSW pumps and motor operated and solenoid valves required to bring the system into service are controlled from the main control rooms. Check valves and manual handwheel operated valves are used to prevent back-flow, accommodate testing, or are used for system isolation. Periodic testing of the PSW valves and pumps (except the portable pump) will be performed in accordance with the Inservice Testing (IST) program.

A separate PSW electrical equipment structure is provided for major PSW electrical equipment. Power is provided from the KHU via a tornado protected underground path. Alternate power is provided by a transformer connected to a 100 kV overhead transmission line that receives power from the Central Tie Switchyard located approximately 8 miles from the plant. These external power sources provide power to transformers, switchgear, breakers, load centers, batteries, and battery chargers located in the PSW electrical equipment structure.

The PSW HVAC is designed to maintain the Transformer Space (main equipment area) and the Battery rooms within their design temperature range. There are two redundant battery systems inside the PSW Building. The redundant battery banks are located in different rooms separated by fire rated walls. One HVAC system is QA-1; the other is non-QA. The hydrogen removal fans shall maintain the hydrogen in the Battery rooms below 2% in accordance with IEEE 484-2002.

Codes and Standards applicable to the Design of the Protected Service Water System

The PSW System requires not only the installation of new equipment and structures but also requires modification of existing systems and structures which have been constructed in accordance with various codes and standards having effective dates during the past 40 years of ONS operation. Depending on the scope of work, new installation or modification of existing equipment and structures, the appropriate effective date and revision of the code or standard is utilized. This information is in the process of being compiled and will be submitted for NRC review on or before January 20, 2012.

The PSW Project is being implemented via thirty nine (39) Design Change Packages (DCPs) with associated Engineering Changes (ECs) as tabulated below.

Design Change Package / Title / Engineering Change #	Status
OD100937 U1 VITAL I&C CABLE REROUTE EC91829	Field Issued
OD100941 U1 MCR ADDITIONS EC91830	Field Issued
OD100950 U1 POWER TO HPI EC91834	Field Issued
OD200925 U2 PZR HTRS & BATT CHRGR PWR EC91849	Field Issued
OD200934 U2 CCW MINI-FLOW EC 91850	Field Issued
OD200938 U2 VITAL I&C CABLE REROUTE EC91851	Field Issued
OD200942 U2 MCR ADDITIONS Pre-Outage EC91853	Field Issued
OD200945 U2 MCR ADDITIONS Outage EC91852	Field Issued
OD200953 U2 POWER TO HPI OUTAGE EC91857	Field Issued
OD200954 U2 POWER TO HPI Pre-Outage EC91858	Field Issued
OD300935 U3 CONDENSATE SUCTION EC91860	Field Issued
OD300939 U3 VITAL I&C CABLE REROUTE EC91861	Field Issued .
OD300943 U3 MCR ADDITIONS Pre-Outage EC91863	Field Issued
OD300955 U3 MCR ADDITIONS Outage EC91866	Field Issued
OD300958 U3 POWER TO HPI Pre-Outage EC91869	Field Issued
OD500920 PSW BUILDING ERECTION EC91870	Field Issued
OD500921 PSW BUILDING EQUIP Part A EC91871	Field Issued
OD500921 PSW BUILDING EQUIP Part B EC91833	Field Issued
OD500922 POWER FEED TO PSW BLDG EC91873	Field Issued
OD500923 13.8KV PSW FEED FROM 100KV EC91874	Field Issued
OD500928 SSF FEED FRM PSW EC91876	Field Issued
OD500932 HEADER PIPING - PUMP TO SG'S EC91877	Field Issued
OD500936 AUX BLDG CABLE TRAY EC91879	Field Issued

Design Change Package / Title / Engineering Change #	Status
OD500940 KEOWEE EMER START REROUTE EC91880	Field Issued
OD500947 UNDERGROUND DUCT BANKS EC91881	Field Issued
OD100924 U1 PZR HTRS & BATT CHRGR PWR EC91826	Design In-Progress
OD300926 U3 PZR HTRS & BATT CHRGR PWR EC91859	Design In- Progress
OD300957 U3 POWER TO HPI Outage EC91868	Design In-Progress
OD500921 PSW BUILDING EQUIP Part C EC91856	Design In-Progress
OD500927 KEOWEE AC POWER TIE-INS EC91875	Design In-Progress
PUMP TIE-IN CABLE PACKAGE EC106526	Design In-Progress
OD500933 NEW PSW PUMP Tie-IN EC91878	Design In-Progress
OD100929 U1 S/G PIPING TIE-INS EC91884	Installation under 50.59
OD500927 KEOWEE AC POWER Mech EC106349	Installation under 50.59
OD500944 ASW DEMOLITION (ALL UNITS) EC95601	Installation under 50.59
OD500946 KEOWEE DEMOLITION EC92519	Installation under 50.59
OD500948 UNDERGROUND RELOCATION EC91832	Installation under 50.59
OE200930 U2 S/G PIPING TIE-INS EC91885	Installation under 50.59
OE300931 U3 S/G PIPING TIE-INS EC91887	Installation under 50.59

Scope descriptions and calculations for each of the above twenty five (25) completed DCPs/ECs which have been field issued are available for NRC review and audit. These scope descriptions and calculations contain executive summaries/problem statements, applicable QA conditions, applicable codes and standards, assumptions and analyses. Based on discussions with the NRC Staff and the volume of this material (25 DCPs/ECs and associated scope descriptions with 400+ calculations for those DCPS/ECs), Duke Energy made PDF files with this information available electronically for audit by the NRC Staff. The electronic files also include a PSW Master AC Power Diagram (Electrical), PSW System (Flow Diagram) In Standby (Mechanical) and a PSW Duct bank and Manhole Location Plan (Civil) to provide summary pictorial scope descriptions to facilitate NRC review.

RAI 63

By letter dated May 25, 2010, the NRC issued RAI 2-28. The licensee responded to the RAI by letter dated August 31, 2010. The response stated, "The battery terminal voltage is based on a minimum value of 105 volt (V) direct current (DC)." Explain the basis for the minimum battery terminal voltage of 105 V DC, and discuss how this value ensures that the minimum voltage requirements of all the downstream equipment fed by the battery will be met. Also describe how the equipment will be capable of performing their design functions at that voltage or component fed from the battery and 105 V DC whichever is higher.

Duke Energy Response

The Protected Service Water (PSW) DC System consists of two QA-1 battery banks with each bank consisting of 60 C&D LCY-39 lead-calcium flooded cells. Only one bank is required to be aligned to the PSW DC System. The other bank is maintained on float charge and is available to be aligned to the PSW DC System by manual breaker operation.

The PSW DC system is designed for the batteries to provide sufficient voltage at the component with an end life battery capacity of 80%, at a minimum electrolyte temperature of 60°F and with two of the cells jumpered-out (i.e. a 58 cell bank) and an end of duty cycle cell voltage of 1.81 VDC. The formula for calculating 105 VDC battery terminal voltage value is found using IEEE-485-1997/R2003 Section 6.1.1 where 58 cells x 1.81 VPC = 105 VDC.

Calculation OSC-9190 Rev. 0 (Protected Service Water (PSW) 125 VDC Power System Analysis) uses ETAP (Electrical Transient Analyzer Program) software which is widely used in both U.S. and international commercial and nuclear power applications. Each version of ETAP undergoes Verification and Validation in accordance with 10CFR Appendix B and Part 21. ETAP's calculation methodology is based on IEEE and ANSI standards including IEEE-308 and IEEE-485. IEEE-308 and IEEE-485 have been endorsed by Regulatory Guides 1.212 and 1.32.

Voltage drops from the panelboards to the end devices are evaluated in separate Design Input calculations associated with PSW-related Engineering Changes. The devices powered from the PSW DC system consist of switchgear and loadcenter breaker control and transfer switch control power.

The calculation concluded that for all cases, the required equipment had adequate DC voltage to perform its design function with the battery at end of life capacity, 60°F electrolyte temperature with two cells removed from the nominal 60 cell bank.

The LCY-39 cells were selected based on a 15% design margin per IEEE-485, an additional 60 Amps margin (10 Amps per panelboard) and a 500 Amp random load that is not an actual PSW load. The 500 Amp random load is not included in the ETAP model but was added for the purposes of completing the IEEE-485 Cell Sizing Worksheet to select the LCY-39 cells and to provide further conservatism in the PSW DC System design. This conservative approach to battery cell sizing provides engineering design margin to allow for future growth on the PSW DC system.

RAI 64

Provide a detailed discussion on the periodic tests that the Protected Service Water (PSW) 125 V DC batteries will be subjected to and how these tests will ensure that the batteries have the capability and capacity to perform their design functions.

Duke Energy Response

The PSW batteries will be periodically tested in accordance with applicable surveillance requirements from NUREG-1430 Vol. 1 Rev. 3.0 Standard Technical Specifications (STS) Babcock and Wilcox Plants Sections 3.8.4 (DC Sources - Operating) and 3.8.6 (Battery Parameters). Performing these surveillances will ensure that the PSW batteries have the capability and capacity to perform their design functions.

The following table lists the PSW battery periodic tests that will be performed.

Periodic Tests for PSW Batteries		
STS Surveillance Number	Description	Frequency
SR 3.8.4.1	Verify battery terminal voltage is greater than or equal to the minimum established float voltage.	7 days
SR 3.8.4.3	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
SR 3.8.6.1	Verify battery float current is ≤ 2 amps.	7 days
SR 3.8.6.2	Verify battery pilot cell voltage is ≥ 2.07 V.	31 days
SR 3.8.6.3	Verify battery connected cell electrolyte level is greater than or equal to minimum established design limits.	31 days
SR 3.8.6.4	Verify battery pilot cell temperature is greater than or equal to minimum established design limits.	31 days
SR 3.8.6.5	Verify battery connected cell voltage is ≥ 2.07 V.	92 days
SR 3.8.6.6	Verify battery capacity is ≥ 80% of the manufacturer's rating when subjected to a performance discharge test or a modified performance discharge test.	60 months AND 12 months when battery shows degradation, or has reached 85% of the expected life with capacity < 100% of manufacturer's rating AND 24 months when battery has reached 85% of the expected life with capacity ≥ 100% of manufacturer's rating

RAI 65

Provide a detailed discussion on the PSW battery room ventilation capability and temperature specifications (both minimum and maximum) and explain how the room temperature will be monitored to ensure that there is no adverse impact on battery performance or service life.

Duke Energy Response

The PSW Building has two Battery Rooms. Each Battery Room has separate ventilation, hydrogen removal, heating and cooling systems consisting of two exhaust fans with associated ductwork, heaters, dampers, and controls. The HVAC systems shall maintain Battery Room temperatures between 60°F and 120°F with a nominal temperature of 70°F. The hydrogen removal function shall maintain the concentration below 2% in accordance with IEEE 484-2002 and Regulatory Guide 1.128.

One of the fans in each room is in continuous operation serving as the operating fan. The other fan serves as a standby fan. These fans provide hydrogen removal, heating and cooling during normal operation. This system, with the exception of the cooling coils, meets QA-1 requirements and shall be seismically mounted to the walls and/or floors above the Battery Rooms in the mezzanine area. The QA-1 system is located entirely within the PSW Building. The cooling coil is non-QA but is seismically mounted within the QA-1 ductwork. The condensers for the coils are located outside the PSW Building. The Battery Room fans provide cooling ventilation in the event of a loss of the non-QA cooling coils (ventilation mode).

To support hydrogen removal during normal operation, the rate of air removed from each Battery Room shall be greater than 10 cubic feet per minute (cfm) but shall not exceed 100 cfm. In this configuration, if the operating fan fails, the standby fan will automatically start for hydrogen removal.

In the ventilation mode, one fan will be in operation for its associated Battery Room. The rate of air removal from the associated Battery Room shall be 1500 cfm. In this configuration, if the operating fan fails, the standby fan will automatically start for Battery Room ventilation. These fans are sized to maintain the Battery Rooms at or below a maximum of 120°F by ventilating the rooms with outside air.

The PSW Building will be inspected during operator rounds every shift and, in addition, an Operating Aid Computer (OAC) alarm is provided in the Control Room if the temperature in the building exceeds specified limits.

RAI 66

By letter dated May 25, 2010, the NRC issued RAI 2-28. The licensee responded to the RAI by letter dated August 31, 2010. The response stated, "The two 300 Ampere (A) DC battery chargers are manufactured by AMETEK." Industry operating experience has shown that momentary overvoltage or undervoltage transients experienced during switching or fault-related perturbations can trigger a self-protecting lockout feature in battery chargers resulting in disabling the chargers. Provide details on magnitude and duration of transient and sustained overvoltage/undervoltage conditions resulting from the perturbations identified above for the 13.8 kilovolt (kV) Keowee Hydro Unit (KHU) underground circuit and how these conditions were considered in the design and procurement of the PSW system battery chargers. Also discuss a perturbation due to lightning on the alternate 13.8 kV overhead circuits from the new 100/13.8 kV substation to the PSW switchgear building in the discussion.

Duke Energy Response

The Protected Service Water (PSW) battery chargers do not have a self-protecting lockout feature for input power undervoltage or overvoltage.

If the input voltage drops below the minimum needed for charger operation, the charger will cease supplying output voltage due to the charger voltage control oscillator circuit no longer having sufficient voltage to provide gating signals to the power silicon controlled rectifiers. After input voltage levels recover, the charger will automatically resume normal operation without requiring operator action.

The battery chargers have an output DC overvoltage shunt trip feature with a time delay set at 30 seconds (adjustable from 0.1 seconds to 100 minutes) which will allow uninterrupted charger operation during brief output overvoltage transients.

If the chargers cease operation due to loss of AC input voltage or high DC output voltage, alarms will be indicated both locally and in the main control room that will allow operators to take appropriate action.

Calculation OSC-9370 (U1/2/3 PSW AC Power Systems Voltage and Short Circuit Analyses) performs evaluations to demonstrate the capability of the PSW electrical system to function under postulated scenarios by comparing the analysis results with equipment ratings for undervoltage, overvoltage, short circuit and cable ampacity. This calculation includes analyses of the battery charger 600 VAC input power from both Keowee Hydro and the alternate 13.8 kV overhead paths from the PSW substation.

Calculation OSC-9832 (U1/2/3 PSW AC Power System - ETAP Model Base File) provides the PSW electrical equipment parameters required as input for OSC-9370.

Both calculations use ETAP (Electrical Transient Analyzer Program) software which is widely used in both U.S. and international commercial and nuclear power applications. Each version of ETAP undergoes Verification and Validation in accordance with 10CFR 50 Appendix B and Part 21. ETAP's calculation methodology is based on IEEE and ANSI standards including IEEE-308 and IEEE-485. IEEE-308 and IEEE-485 have been endorsed by Regulatory Guides 1.212 and 1.32.

The PSW battery charger procurement specification has a nominal input voltage of 600 VAC with an allowable range from 510 VAC (-15%) to 660 VAC (+10%).

The calculated sustained (steady-state) battery charger input voltage range with the PSW electrical system fed by Keowee is from 581 to 623 VAC and with the 13.8 kV alternate overhead feeding PSW, from 581 to 629 VAC. All calculated sustained values were within the allowable PSW battery charger voltage range.

The calculated transient (motor starting) minimum battery charger input voltage with the PSW electrical system fed by Keowee is 510 VAC which occurs after approximately 1 second after motor starting. 510 VAC is the minimum allowable battery charger input voltage range. In approximately 6 seconds, battery charger input voltage has recovered to 593 VAC which is well within the battery charger input voltage range.

With the 13.8 kV alternate overhead feeding the PSW electrical system, the minimum battery charger voltage is 501 VAC that occurs approximately 5 seconds after motor starting. In approximately 13 seconds, battery charger input voltage has recovered to 576 VAC which is within the battery charger input voltage range.

While the alternate overhead case is slightly below the minimum voltage rating of 510 VAC, as discussed above, this is acceptable since the battery chargers will automatically resume normal operation after input voltage has recovered to normal limits.

During a brief interruption of battery charger operation during motor starting for either the Keowee or 13.8 kV overhead PSW power sources, the PSW DC system will be capable of performing it design function since the battery will maintain the required system voltage until battery charger input voltage recovers.

The overhead path from the 100/13.8 kV substation to the PSW switchgear is equipped with lightning arrestors per Duke Energy Distribution Standards to minimize the affect of lightning-induced transients on the PSW electrical system. A total of five lightning arrestors are installed on the overhead path - one at each end and three in between.

RAI 67

By letter dated May 25, 2010, the NRC issued RAI Nos. 2-27, 2-28 and 2-29. The licensee responded to the RAIs by letter dated August 31, 2010. In its response the licensee stated to, that equipment protection and coordination studies are still under development and are not available for review. The anticipated completion date for the protection and coordination studies is December 2010. By letter dated October 8, 2010 the NRC issued 44. The licensee responded to the RAI by letter dated December 7, 2010. The RAI response on equipment protection and coordination referred back to the above licensee's response to the NRC staff's RAI dated August 31, 2010. Provide a summary of the equipment protection and coordination analyses for the entire PSW system, and describe, in detail, the acceptability criteria that were used in determining that adequate protection and coordination would be provided.

Duke Energy Response

OSC-9831 (Protective Relay Settings Associated with PSW Switchgear), was used to determine proper settings to provide equipment protection and coordination for all 600V load center breakers, 4.16kV relays and 13.8kV relays associated with the PSW switchgear system and the 600V breaker of the alternate feed to the XPSW Motor Control Center (MCC). OSC-9831 has been uploaded to the Share Point Site.

Acceptability Criteria were met in all but two cases for overcurrent relay coordination. Coordination of the device 51 on breaker OTS1-0 with breaker B7T4 is not required. However, breaker OTS1-0 should always trip for a fault on the OTS1 bus, even if breaker B7T4 also trips. Therefore, the time delay setting of the 51L relay at B7T4 is adjusted to ensure that the OTS1-0 breaker will open for a fault on OTS1 bus. Coordination of the 51L relay at the B7T4 compartment doesn't exist with breaker B7T1 (bus tie) at the maximum fault current. However, since B7T1 relay has a different trip characteristic, it may cause B7T1 to trip before B7T4 for lower values of fault current. Because the SSF Feeder is the only load on B7T bus, no coordination is needed. If new loads are added to bus B7T, calculation OSC-9831 should be reviewed and relay coordination should be performed with the tie breaker (B7T1) and the SSF Feeder breaker (B7T4).

At the 600V level, because of restraints in achieving coordination with the upstream RW2 Main breakers, the Radwaste feeder breaker does not coordinate with the XPSW MCC Main breaker. There is a possibility that the Radwaste feeder breaker will trip before the XPSW Main breaker. However, this is acceptable since in either case, the XPSW MCC will be de-energized. In other cases at the 600V level, in order to coordinate with the pickup of the largest load breaker in an MCC, the feeder can't be set to protect the cable for overload. The maximum loading of these MCCs are reviewed to ensure the cable will not be overloaded. If MCC loading is increased, these breaker settings should be reviewed. The feeder breaker does protect the cable for faults, but coordination with the Main Breaker can't be achieved. This is acceptable since the end result of either the MCC Main Breaker or the feeder breaker tripping is de-energizing the MCC and clearing the fault.

The acceptability criteria used for the analyzed equipment in OSC-9831 is summarized as follows:

Overcurrent devices are set according to ratings of equipment protected and checked for time-current coordination. Coordination between 600V breakers is established when their Time Current Trip Characteristics do not overlap. Coordination between a 600V breaker and a fuse is established when their Time Current Trip Characteristics do not overlap. In order to establish coordination between an overcurrent relay and downstream 600V breakers, the Coordination Time Interval (CTI) between the two devices should be at least 0.25 seconds at the maximum fault current seen by the two devices. In order to establish coordination between two overcurrent relays, the CTI between the two devices should be at least 0.3 seconds at the maximum fault current seen by the two relays. These CTI guidelines incorporate relay operating time tolerances and include circuit breaker operation time of 0.08 seconds and setting errors/relay tolerance of 0.22 seconds. There is no over-travel in the case of static relays. Static relays are used at the PSW Switchgear.

The ampacities of 600 V MCC Feeder cables have been taken from analysis OSC-9370 . These ampacities are based on the cumulative effect of loading the MCC feeders in the duct bank to provide the optimal ampacity in the duct bank. These loadings have been increased to the point where a cable in the duct bank reaches a temperature of 90°C.

<u>4160 V Feed Breaker to 4160 V / 600 V PX13 Transformer</u> - The transformer feeder time delay overcurrent relay should have a pickup setting of 150% to 200% of the transformer full load current. It should coordinate with any downstream time delay relays. The instantaneous overcurrent relay should be set high enough to avoid tripping when a fault occurs on the bus feeder on the transformer's low voltage side, but low enough to detect severe faults which may occur in the transformer. The instantaneous pickup current should be 2x maximum low side fault current, and above the maximum inrush current.

<u>4160 V Motors Fed from PSW Bus B6T – HPI Injection Pump Motors 1A, 1B, 2A, 2B, 3A & 3B (Cubs. B6T-3, 4 & 5)</u> - The relay settings should be such that they will allow the motor to accelerate the connected load to the rated speed without tripping. The relay should protect the motor from exceeding its thermal capability during locked rotor and overload conditions. The relay should immediately clear any faults on the motor feeders. These breakers are alternate feeds to existing motors that are presently fed from the Oconee 4160 V auxiliary system. Existing relay settings have been taken from OSC-4300 Appendix H and are not

reanalyzed in this calculation. The trip characteristics of the existing protective relays are duplicated to provide settings for the new relays.

4160 V PSW Main Pump Motor (Cub. B6T-6) - The relay settings should be such that they will allow the motor to accelerate the connected load to the rated speed without tripping. The relay should protect the motor from exceeding its thermal capability during locked rotor and over load conditions. The relay should immediately clear any faults on the motor feeders. The long time pickup should be set between 125% and 150% of the motor full load current. The time dial setting of the Time Over-current relay should allow coordination of the relay trip characteristic with the motor thermal limit curve and the motor acceleration time-current curve. The pick-up of the short time delay unit should be set at about 125% of the motor locked rotor current and the delay of the short time delay unit should not cause a trip during motor start. The standard instantaneous element should be set at about 250% of the motor locked rotor current.

4160 V PSW Booster Pump Motor (Cub. B6T-7) - The relay settings should be such that they will allow the motor to accelerate the connected load to the rated speed without tripping. The relay should protect the motor from exceeding its thermal capability during locked rotor and over load conditions. The relay should immediately clear any faults on the motor feeders. The long time pickup should be set between 125% and 150% of the motor full load current. The time dial setting of the Time Over-current relay should allow coordination of the relay trip characteristic with the motor thermal limit curve and the motor acceleration time-current curve. The pick-up of the short time delay unit should be set at about 125% of the motor locked rotor current and the delay of the short time delay unit should not cause trip during motor start. The standard instantaneous element should be set at about 250% of the motor locked rotor current.

Device 51 Settings at PSW Breaker B7T, Compt 4 (Feed to SSF) - Coordination of this relay with downstream device 51 on breaker OTS1-0 is not required. However, breaker OTS1-0 should always trip for a fault on the OTS1 bus, even if breaker B7T4 also trips. Therefore, the time delay setting of the 51L relay at this compartment is adjusted to ensure that the OTS1-0 breaker will open for a fault on OTS1 bus.

4160 V Buses B6T and B7T Tie Breaker - The Tie Breaker relay settings should provide coordination with the Load Breakers and upstream coordination with the Main Breakers. The breaker should not trip during normal operation.

4160 V Buses B6T and B7T Main Breakers - The Main Breaker relay settings should provide coordination with the Load Breakers and the Tie Breaker. The breaker should not trip during largest motor start when the bus is fully loaded. The settings should provide overload protection to the feeding transformer.

Transformer CT6 and CT7 4160V Ground Overcurrent Relay - The relay should provide protection for ground faults on the 4160V side of the transformers and backup protection for ground faults on 4160V buses B6T and B7T.

13.8 kV CT6 and CT7 Feeder Breakers A and C - The transformer feeder time delay overcurrent relay should have a pickup setting of 150% to 200% of the transformer full load current. It should coordinate with any downstream time delay relays. The instantaneous overcurrent relay should be set high enough to avoid tripping when a fault occurs on the bus feeder on the transformer's low voltage side, but low enough to detect severe faults which may occur in the transformer.

13.8 kV CT6 and CT7 Feeder Breakers B and D (Supplied by Fant Line) - The transformer feeder time delay overcurrent relay should have a pickup setting of 150% to 200% of the transformer full load current. It should coordinate with any downstream time delay relays. The instantaneous overcurrent relay should be set high enough to avoid tripping when a fault occurs on the bus feeder on the transformer's low voltage side, but low enough to detect severe faults which may occur in the transformer.

Instantaneous ground fault relays on the 4.16 kV bus feeders have been set to a pickup of 5A and time delay of 0.1 seconds based on Duke Energy operational experience.

Developed using the following Standards:

- IEEE Standard C57.12.00 – 2006
- NEMA C50.41-2000 (ANSI C50.41-2000) Polyphase Induction Motors for Power Generating Stations
- IEEE Standard 242-2001
- Electrical Division Engineering Criteria Manual, RE – 3.01 Rev. 6 Relaying – Auxiliary Systems – Equipment Protection Settings.

RAI 68

The licensee's O-6700 drawing reflects degraded voltage relays and loss of voltage relays on the 13.8 kV PSW switchgears. Provide a summary of the settings for these relays. Also identify the most-limiting equipment or component and provide its minimum voltage requirement. Discuss how the most-limiting equipment or component was considered in determining the degraded voltage relay setpoint.

Duke Energy Response

In OSC-9831 (Protective Relay Settings Associated with PSW Switchgear), the degraded voltage relays are set to pick up at 7700V primary L-N (Tap = 110V) and to drop out at 7623V primary L-N (99% of pickup = 108.9V). The time dial tap is set to 6 (1.0 seconds). The undervoltage relays are set to pick up at 5600V primary L-N (Tap = 80V). The undervoltage time dial tap is set to 2 (2 seconds).

At the dropout point of the degraded grid relays, the OTS1 voltage is 99% of rated buss voltage, which is required for SSF pressurizer heaters. This is the most limiting equipment considered for the degraded grid relay setting.

RAI 69

In Enclosure 2, page 14 of the June 26, 2008, LAR concerning Tornado mitigation, the licensee stated: "The PSW switchgear will also provide a backup power supply to the SSF [Standby Shutdown Facility] via an underground path as additional defense-in-depth." Discuss the following capabilities of the PSW electrical power system to supply backup power to the SSF: (1) automatic or manual operation, (2) expected order of availability of power supply to the SSF, (3) the time frame this back up power will be expected to be available, and (4) evaluation and conclusion of the time for the availability of PSW backup power in automatic and/or in manual operation.

Duke Energy Response

1) The backup power to the SSF from the PSW switchgear requires manual operation of control switches located in the SSF control room.
2) The expected order of availability of power to the SSF following a tornado is as follows:
    1. Unit 2 Main Feeder Buss (if available)
    2. SSF Diesel
    3. PSW B7T switchgear (or B6T with tie-breaker closed)
3) The PSW 4KV electrical system is normally supplied from an offsite power source. A Keowee hydro generator provides an independent and redundant onsite power source to the PSW 4KV power system. At least one of these power sources will be available after a tornado for backup power to the SSF within 72 hours.
4) At least one of the power sources will be available after a tornado for backup power to the SSF within 72 hours. Refer to RAI 98 response for additional information.

RAI 70

Confirm that all electrical design calculations, analyses, and drawings associated with the proposed PSW electrical power system are approved and final.

Duke Energy Response

The PSW project (electrical, civil and mechanical scope) contains thirty nine (39) Design Change Packages (DCPs):

- Seven (7) of these DCPs are being implemented utilizing the 50.59 process.
- Twenty-five additional DCPs are within the scope of the PSW LAR and have been approved and released for field implementation. Design documents including electrical design calculations, analyses and drawings associated with these released DCPs have been approved. In some instances, there will be some subsequent calculations, analyses or drawings and revisions to these documents to close out open items that are being tracked.
- Seven (7) remaining DCPs are In-Progress. The remaining seven (7) DCPs will be released on a schedule that supports future field implementation start dates for the scope of these DCPs. Calculations, analyses and drawings will be available for NRC audit as these DCPs are completed.

The final DCP is projected to be approved mid-February 2012 with documentation for that final DCP available for transmittal on or before March 1, 2012.

RAI 71

In the June 29, 2009 LAR, the licensee stated that equipment qualification of shutdown components is only required in the east penetration rooms of the auxiliary building for postulated main feedwater and main steam HELBs. Explain why equipment qualification, or more appropriately, environmental qualification of shutdown components in other areas, including the west penetration rooms, is not required.

Duke Energy Response

In the June 29,2009 LAR, the licensee has not stated that equipment qualification of shutdown components are only required in the East Penetration Rooms (EPR). Duke Energy provided a response in a letter dated October 23, 2009 to a request for additional information contained in a letter from the NRC dated July 24, 2009. In response to RAI 15, Duke Energy stated, "As discussed on pages 8-31 of the HELB Report (ONDS-351, Rev. 2), the only areas of the station where environmental qualification was considered due to a harsh environment following a postulated HELB outside containment, are the East Penetration Room (EPR) and the West Penetration Room (WPR). The breaks of concern are the Main Steam line and the Main Feedwater lines in the EPR. This was also the case addressed in the original MDS Report No. OS-73.2. The response goes on to describe that the equipment located in both the EPR and the WPR that is required for mitigation of the breaks in the EPR have been qualified for the resulting environmental profile which extend to both the EPR and the WPR.

No changes to the current EQ licensing basis have been requested in response to the HELB LAR. The current EQ licensing basis for HELBs outside containment is based on the original HELB report contained in MDS Report No. OS-73.2. Breaks were postulated in the yard, the Auxiliary Building, and the Turbine Building. The only area of the plant where appreciable pressurization could be experienced from postulated HELBs outside containment were the penetration rooms. The HELBs of concern were the main steam line and the main feedwater lines in the EPR. Pressure and temperature profiles were calculated and formed the basis for the environmental profiles that were subsequently adopted in the EQ program. Postulated HELBs in the Turbine Building resulted in a negligible pressure and temperature response. Therefore, HELBs occurring inside the Turbine Building were not considered to create a harsh environment. No adverse environmental profiles were established for the Turbine Building in the EQ program.

The reconstitution of the HELB licensing basis has postulated breaks inside the Auxiliary Building and the Turbine Building similar to the original HELB report that established the basis for harsh environmental areas outside containment. The only area of the plant containing equipment needed for safe shutdown and plant cooldown to cold shutdown, where appreciable pressurization could be experienced, continues to be the penetration rooms. As a result there are no changes to the EQ licensing basis.

It was noted in the reconstituted HELB report that some postulated breaks in the plant heating piping could result in a slight pressurization and/or a steam/air environment in selected rooms inside the Auxiliary Building. It was determined that the impact would not result in a loss of systems needed for safe shutdown or plant cooldown to cold shutdown. As such, no new environmental qualifications were imposed for equipment located in these areas.

RAI 72

Explain how the proposed PSW system meets NRC requirements with regard to the design, installation, and testing of electrical equipment.

Duke Energy Response

The electrical equipment for the PSW system is designed, installed and tested in accordance with the Duke Energy Topical Report which is contained in Chapter 17 of the Oconee UFSAR.

The Topical Report describes the Duke Energy Quality Assurance Program (QAP). The Duke Energy QAP conforms to applicable regulatory requirements including 10CFR50 Appendix B and approved industry standards including ANSI N45.2-1971 and ANSI N18.7-1976. The QAP also conforms to Regulatory Guides (with clarifications, modification or alternatives) as listed in Table 17-1.

Per Table 17-1 of the QAP, ONS conforms to Regulatory Guides 1.28 Rev. 2 (Quality Assurance Program Requirements Design and Construction) and 1.30 Rev. 0 (Quality Assurance Requirements for the Installation, Inspection and Testing of Instrumentation and Electric Equipment).

Lower tier Duke Energy documents that govern the design, installation and testing of the PSW electrical equipment in accordance with the QAP include EDM-140 (Procurement Specifications for Equipment), EDM-601 (Engineering Change Manual), NSD-301 (Engineering Change Program) and NSD-408 (Testing).

RAI 73

Explain how you have addressed the findings identified in NRC Inspection Reports 05000269/2010004, 05000270/2010004, and 05000287/2010004 (ADAMS Accession No. ML103020265).

Duke Energy Response

Finding 1:

A Green NRC-Identified NCV was identified for the licensee's failure to comply with 10 CFR 50.49(f) in that Rosemount transmitters, Limitorque valve actuators, and Electrical Penetration Assemblies (EPAs), each an item of electric equipment important to safety, were found installed in a configuration other than the tested configuration and the licensee did not establish the qualification of the installed configuration.

Status 1:

The Rosemount transmitter issue is documented in Oconee Nuclear Station (ONS) Problem Identification Program (PIP) PIP report O-10-6409. The original non-compliance dealt with shipping plugs still installed and inadequate housing torque. These issues have been corrected by replacing the plastic shipping plugs with stainless-steel plugs and by retorquing, as necessary, the housings to their correct design values.

The Limitorque issue is documented in PIP O-10-6515 and O-10-8395. This non-compliance dealt with limit switch compartments (LSC) installed vertically down and no T-drain installed on the LSCs. The NRC did not accept the Duke Energy response given in PIP O-10-6515; therefore, each was declared operable but degraded-nonconforming (OBDN) in PIP O-10-8395. Duke Energy calculation DPC-1381.05-00-0049/OSC-10359, approved on September 29, 2011, addresses the issue. T-drains were installed in the LSCs on Unit 2. Plans are to walk down Units 3 and 1 during the upcoming spring and fall (2012) refueling outages and make repairs as necessary.

The EPA issue is documented in PIP O-10-8398. This non-compliance dealt with not testing hybrid EPAs as complete assemblies. Two EPAs were declared operable but degraded-nonconforming in PIP O-10-8398. Duke Energy plans to submit an Exemption Request to resolve the nonconforming condition. No field work is required.

Finding 2:

An NRC-identified Green NCV of 10 CFR 50, Appendix B, Criterion V, Instructions, Procedures and Drawings, was identified for the licensee's failure to install Fiber Reinforced Polymer (FRP) on the Unit 1 Auxiliary Building wall in accordance with the installation procedure. The licensee had not identified and repaired all wall defects greater than 0.75 inches deep as required by procedure.

Status 2:

The apparent cause evaluation concluded this event was isolated to the three (3) Unit 1 wall elements that had the Fibrwrap® installed at the time the issue was identified. There were "pin-hole penetrations" found on subsequent wall elements that may have existed on these three wall elements. Extent of Condition reviews eliminated the possibility of any concern regarding the three wall elements. Once the penetrations were identified, the epoxy injection repair method was used to repair the holes on the remaining Unit 1 wall elements. This pin-hole identification and repair process was also incorporated into the installation procedures for Unit 2 and Unit 3 (PIP O-10-7414).

Finding 3:

An Unresolved Item (URI) was identified when water was observed in the 1-RIA-40 and 2-RIA-40 rotameters. The rotameters were downstream of the detectors indicating that the monitors had been affected by the presence of condensed water.

Status 3:

Duke Energy plans to originate an Engineering Change (EC) for each Unit to replace each existing sample dryer and then re-align the sample flow through the new dryer upstream of the RIA-40 sample skid (PIP O-10-6151).

Finding 4:

A NRC-Identified Green NCV of 10 CFR 50.49(l) was identified when the licensee did not follow the requirements for replacing components within EPAs when existing components qualified under the Division of Operating Reactors, Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors (DOR Guidelines), dated November 1979, were combined with replacement components qualified to current standards. The outboard Viking EPA terminal box and associated terminal blocks, not qualified under current standards, were left in 86 EPAs that had been upgraded and made available for use in safety-related or environmentally-qualified applications.

Status 4:

This EPA issue is documented in PIP O-10-1383. This non-compliance dealt with mixing original parts that met DOR Guidelines with replacement 10CFR50.49 qualified parts. Affected EPAs were verified to not have circuits that were required to be qualified. PIP O-10-1383 includes actions for Engineering Changes (ECs) to update affected documents to state that these EPAs are not to be used for EQ loads. The following ECs have been created for the EQ penetrations: (U1) EC107282, (U2) EC107285, and (U3) EC107286.

RAI 74

By letter dated October 8, 2010 the NRC issued RAI 28. The licensee responded to the RAI by letter dated December 7, 2010. In the response to RAI 28, the licensee stated that postulated water entry through the weep holes is not a concern since normal and accident conditions for the penetration rooms does not include spray or submergence. The NRC staff understands that the electrical penetrations will be subjected to a steam environment. Describe the impact of steam entering the penetration boxes through the weep holes on the environmental qualification and performance of the electrical components contained within these penetrations.

Duke Energy Response

For a MSLB inside the East Penetration Room, the Oconee Environmental Qualification Criteria Manual (EQCM) has determined that the electrical penetration boxes will be exposed to 100% relative humidity. The EQCM does not postulate direct steam impingement for a MSLB.

The ONS Environmental Qualification Maintenance Manuals for the Viking and Conax/Viking hybrids state that the electrical penetration boxes do not require environmental sealing and are vented. The original configuration of the Viking penetration boxes had a mesh grating as a front cover which was subsequently replaced with solid covers to increase personnel safety and equipment reliability.

Calculation OSC-8505 (Oconee HELB EQ Analysis for Penetration Rooms) reviewed the Viking qualification test report and determined that the penetrations (including the terminal blocks) were tested in a 100% relative humidity environment. The calculation concluded that for a HELB, there would not be a long duration high level of ambient pressure that would result in a forcing function that would move condensation into the boxes.

As stated in RAI 18 of Duke Energy RAI Response Letter dated October 23, 2009, the weep holes were installed to address NRC staff concerns on Viking penetration box drainage. As part of this response, Duke Energy committed to install weep holes which were considered an enhancement and did not change the original qualification of the Viking electrical penetrations. Prior to weep hole installation, the ONS EQ engineer reviewed the acceptability of the weep holes and determined there would be no impact with respect to environmental qualification.

Therefore, the weep holes installed on the low-voltage Viking and Conax/Viking hybrid penetration boxes located in the penetration rooms will not adversely affect the environmental qualification and performance of the electrical components contained within these penetrations.

RAI 75

Explain how your assessment of the impact of the proposed PSW system on the environmental qualification of equipment was completed without having fully completed the design of the PSW system.

Duke Energy Response

The PSW system has been designed to provide mitigation of postulated high energy line breaks (HELBs) occurring inside the Turbine Building. The postulated HELBs inside the Turbine Building are not expected to create a harsh environment inside the Control Rooms (CR), Electrical Equipment Rooms (EER), Cable Spreading Rooms (CSR), and the balance of the Auxiliary Building. The new equipment specifications for PSW related equipment were written to meet the existing temperature profiles established for the CR, EER, CSR, and the balance of the Auxiliary Building following a design basis accident as documented in the Environmental Qualification Criteria Manual (EQCM). The PSW system is a new high energy system that will be installed inside the Auxiliary Building. The PSW system is only expected to be used under extreme emergencies where normal and emergency systems located inside the Turbine Building are damaged from postulated HELBs or tornado. The PSW system would also be expected to operate for short durations to perform routine testing to assure operability of the system. Since the PSW system is not expected to be operated in excess of 1% of the total plant operating time, the system has been excluded from the postulation of HELBs and critical cracks. As such, there are no new postulated HELB interactions created by the installation of the PSW system. However, the new PSW pump motor and PSW electrical equipment are expected to change the heat loads inside the Auxiliary Building, thus impacting the heatup calculations for the Auxiliary Building. Calculations have not been completed for the additional heat loads created by the PSW equipment. Should the calculations result in Auxiliary Building temperatures exceeding the profile used in the equipment specifications, additional modifications would be implemented to provide adequate heat removal capability to maintain Auxiliary Building temperatures within the equipment specifications.

RAI 76

By letter dated October 8, 2010 the NRC issued RAI 42. The licensee responded to the RAI by letter dated December 7, 2010. The response stated that a Failure Modes and Effects Analysis/Single Failure Analysis (FMEA/SFA) will be performed for the PSW electrical system. Provide the results of the FMEA/SFA for the PSW system.

Duke Energy Response

The failure modes and effects analysis / single failure analyses (FMEA / SFA) is in progress. Projected approval date is mid-February 2012 with documentation available for transmittal to the NRC on or before March 1, 2012.

FMEA / SFA analyses are performed in accordance with Duke Energy Engineering Directive: Guidelines for Performing a Failure Modes and Effects Analysis and Single Failure Analysis. Documentation of these analyses is in accordance with Duke Energy Engineering Directive: Engineering Calculations / Analyses with a preparer, checker and approver. FMEA / SFA analyses and associated calculations prepared, checked and approved by a vendor are also approved by Duke Energy.

The Duke Energy FMEA / SFA process was created utilizing numerous internal and external documents and standards. The external documents/standards include:

- ANSI/ANS-58.9-1981, "Single Failure Criteria for Light Water Reactor Safety-Related Fluid Systems".

- Safety Series No. 50-P-1, "Application of the Single Failure Criterion", International Atomic Energy Agency, Vienna, 1990, "Application of the Single Failure Criterion", (A publication within the NUSS Program).
- IEEE Std. 603-1998, "IEEE Standard Criteria for Safety Systems for Nuclear Power Generating Stations"
- IEEE Std. 379-1994, "IEEE Standard Application of the Single-Failure Criterion to Nuclear Safety Systems"
- IEEE Std. 352-1987, "IEEE Guide for General Principles of Reliability Analysis of Nuclear Safety Systems"
- IEEE Std. 1028-1997, "IEEE Standard for Software Reviews"
- NUREG 492 "Fault Tree Handbook"
- Regulatory Guide 1.53 "Application of the Single-Failure Criterion to Safety Systems"
- Regulatory Guide 1.168 "Verification, Validation, Reviews, and Audits for Digital Software used in Safety Systems of Nuclear Power Plants"
- BTP-19 "NUREG 0800 - Standard Review Plan Chapter 7, Branch Technical Position HICB 7-19" Guidance for Evaluation of Defense-in-Depth and Diversity in Digital Computer based Instrumentation and Control Systems."

The FMEA / SFA analyses evaluate the effects of failures of each element of the system and will address:

- Essential functions
- Components needed for those essential functions
- How each component can conceivably fail. For instrumentation, failure modes other than "on" or "off" are considered.
- What are the effects if the failure does occur
- Is the failure in the safe or unsafe direction
- How the failure is detected
- Inherent provisions provided in the design to compensate for the failure
- Operating errors that should be considered.

RAI 77

Describe the capability of the PSW system to be controlled and monitored from the remote/safe shutdown facility.

Duke Energy Response

The PSW System is controlled from the Main Control Room. The Standby Shutdown Facility (SSF) cannot control the PSW system with the exception of closing the OTS1-0 feeder breaker in the SSF 4.16kV switchgear to the power source from the PSW system. Only power to OTS1 from PSW can be monitored via local meters at the SSF.

RAI 78

Provide a detailed discussion on how the electrical power systems of the PSW system will be installed such that they are physically separate and independent.

Duke Energy Response

The PSW electrical system is a single train system; however, the PSW Main pump circuits, Booster pump circuits and associated valve circuits are mutually redundant to the SSF ASW pump and valve circuits. Red PSW cables are not to be routed in the West Penetration Rooms or the Cask Decontamination Rooms to ensure the mutually redundant cables are kept physically separate. The alternate feeder from the PSW to the SSF may be routed without any separation requirements from SSF cables. This will be controlled by Duke Energy Design Criteria DC 3.13, "Oconee Nuclear Station Cable and Wiring Separation Criteria." DC 3.13 provides guidance for cable routing and installation which has been revised to include PSW-related cables. DC 3.13 references IEEE Standard 603-1980, IEEE Standard Criteria for Safety Systems for Nuclear Power Generating Stations.

RAI 79

By letter dated October 8, 2010 the NRC issued RAI 13. By letter dated December 7, 2010, the licensee responded to the RAI. The response to, the RAI included comments concerning the design of structures, separating high energy lines from essential systems and components, covered pressurization and pressure relief features. Regarding this section of the Branch Technical Position (BTP) MEB [Mechanical Engineering Branch] 3-1, please address how impact, pipe whip and jet impingement are addressed, as they can also be consequences of the pipe break.

Duke Energy Response

Analysis of structures separating high energy lines from essential systems and components were evaluated if such structures were impacted by either a pipe whip or jet impingement. The revised ONS HELB strategy is predicated on separation of essential systems (e.g. those systems and components necessary to reach safe shutdown) from the postulated high energy line break. For breaks postulated to occur in the Turbine Building, systems and components located in the Auxiliary Building or the Standby Shutdown Facility (SSF) would be available for mitigation of the effects from the break. For breaks postulated to occur in the Auxiliary Building, systems and components located in the Turbine Building or SSF would be available for mitigation of the effects from the break.

The Turbine/Auxiliary Building wall provides the physical protection for breaks occurring in the Turbine Building from affecting systems and components in the Auxiliary Building credited for break mitigation. The same wall provides physical protection for breaks occurring in the Auxiliary Building from affecting systems and components in the Turbine Building credited for mitigation. The SSF is a standalone building that has no physical connection to either the Auxiliary Building or the Turbine Building.

Surveys of postulated break locations in both the Turbine Building and Auxiliary Building indicated that no interactions with the Turbine/Auxiliary Building wall would occur from postulated breaks located in the Auxiliary Building. These same surveys indicated several interactions that could occur with the Turbine/Auxiliary Building wall from postulated breaks located in the Turbine Building. As completed for other postulated breaks, the initial thrust and steady state thrust forces (pipe whip) were calculated from Appendix B of ANS/ANSI 58.2 (See RAI 85 response for further information regarding the use of ANS/ANSI 58.2). Jet impingement effects were calculated in accordance with NUREG/CR-2913.

RAI 80

By letter dated October 8, 2010, the NRC issued RAI 13. The licensee responded to the RAI by letter dated December 7, 2010. In the response on page 4 of 11 of Table RAI-13 of the Attachment to the RAI the licensee discusses justification for not defining breaks at locations where thermal stresses exceed 0.8 S_a. In the response, the licensee states:

Giambusso/Schwencer included the requirement to postulate break locations where the actual stress exceeded .8 S_A. However, BTP MEB 3-1 includes no such requirement. Duke Energy concluded that the omission of the thermal stress threshold in BTP MEB 3-1 is recognition by the regulatory authorities that thermal stress, in the absence of primary stress, cannot cause pipe rupture failures.

In fact, this limit has been modified, not dropped. Credit for margin in sustained stress has been extended to thermal stress. The limit with additional margin is 0.8 $(kS_h + S_a)$ in BTP MEB 3-1.

In the response, the licensee stated:

Repeating cycles of thermal stress exceeding the yield stress may result in cracking due to fatigue, however, the potential for critical crack formation is addressed by the postulation of critical cracks where the actual stress exceeds the crack stress threshold of .4 x $(S_A + S_H)$.

The consequences of a crack do not envelope those of a break. For this argument to be effective, the formation of a crack would need to preclude the formation of a break. This would require a demonstration that fatigue cracks would propagate through the pipe wall and cause a leak before they propagated along the wall to create a critical crack leading to fracture; a break. Taken all together, the licensee's arguments offer elements that are all part of the leak-before-break methodology discussed in the Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR [Light Water Reactor] Edition (NUREG-0800), Section 3.6.3, "Leak-Before-Break Evaluation Procedure." Please address whether the ONS units meet the provisions of this document for these elements.

Duke Energy Response

The current ONS HELB licensing basis for stressed based break locations is Giambusso (0.8S_A). The break stress threshold in BTP MEB 3-1 is used in the revised ONS HELB Program to identify break locations. This includes the postulation of breaks in analyzed piping that contains seismic loading where the primary plus secondary stress equals or exceeds the quantity 0.8$(S_h + S_A)$. Thermal fatigue stresses alone (i.e., secondary stresses) do not fail piping. Therefore the original Giambusso/Schwencer break criteria based solely on S_A is not appropriate, and the BTP MEB 3-1 break threshold is used.

The current ONS Licensing basis for crack locations is a non-deterministic Giambusso criteria (worst effects). The ASME Code discussion recognizes that self limiting (secondary) thermal stresses, even above yield, does not fail piping and therefore, for cracks, the $0.4(S_h + S_A)$ is an appropriate stress limit for crack postulation also taken from BTP MEB 3-1.

The revised outside containment ONS HELB Program does not use Leak-Before-Break methods to link crack and break locations. For rigorously analyzed piping systems, break and crack locations are based only on stress values, and then cracks and breaks are evaluated for their different effects, as required by Giambusso/Schwencer.

RAI 81

By letter dated October 8, 2010 the NRC issued RAI 13. The licensee responded to the RAI by letter dated December 7, 2010. The licensee's response to the addressed the inaccessible of girth welds by stating:

As described in ONDS-351 (Section 8, Item 5) each MFDW guard pipe encloses the postulated MFDW break location(s). Since the downstream elbow girth welds are adjacent to the postulated break location inside the guard pipe, assuming a break at the inaccessible weld(s) would result in no greater consequences than those that would occur for break(s) postulated inside the guard pipe.

Please address whether there is a separation distance beyond which welds would not be considered adjacent.

Duke Energy Response

There is no specific separation distance beyond which welds would not be considered adjacent. The subjective word 'adjacent' in this specific application means the distance from the RB Wall side of the 14" long collar, under the 12" long guard pipe and on to the first weld on the MFW elbow. This is a distance of about 18.5" (Penetration #25) and 24" (Penetration #27). The collar/guard pipe is designed to withstand the pressure loads as a result of a break anywhere under these components. Since they surround a straight piece of 24" nominal diameter pipe, the dynamic and jet effects of a piping break under the collar/guard pipe up to and including the butt weld at the elbow will result in the same dynamic forces, the same pipe reactions and no greater consequences than those breaks initiating from under the guard pipe alone.

RAI 82

By letter dated October 8, 2010 the NRC issued RAI 32[H]. The licensee responded to the RAI by letter dated December 7, 2010. In the licensee's response to the RAI, the licensee provided a copy of Revision 3 of "HELB Outside Containment Walkdown Criteria & Requirements" (Reference 10.3.17 of ONDS [Oconee Nuclear Design Study] 351, Revision 2). The NRC staff has reviewed the document and has the following questions and requests for clarification.

Section 5.1, ii) states that "Non-liquid piping systems (air, gas) with a maximum operating pressure less than or equal to 275 psig are not considered high energy, regardless of temperature." Please provide the basis for this statement.

Section 5.4 discusses critical cracks, and leakage cracks, and dismisses the latter from consideration in the HELB criteria or design bases for piping outside containment. BTP MEB 3-1, Revision 2, June 1987, specifically requires addressing leakage cracks. Please confirm that the term leakage crack has the same meaning in both documents. Please address the difference between critical cracks and leakage cracks.

The pipe diameter used for longitudinal crack dimension is specifically mentioned as the inner diameter (ID). BTP MEB 3-1, Revision 2, June 1987, mentions diameter, without specifying ID or outside diameter (OD). Please explain why the ID was chosen over the OD for calculation purposes.

Duke Energy Response

Part A: Air or other gasses do not have the density or the phase change that subcooled or saturated water conditions have during depressurization. They also do not have the wetting and flooding concerns. The nitrogen and hydrogen lines at ONS do not exceed temperatures of 200F. The air systems in the Auxiliary and Turbine buildings all have operating temperatures less than 425F (Backup Instrument Air) and some (Service and Breathing) Air systems have after-coolers that limit actual air temperatures to a maximum of 30F above ambient. Therefore, with low density and no phase change, the identification and protection from the effects of low pressure and low temperature air and gas lines are not included in the revised ONS HELB Criteria.

Part B: The terms are not the same. A 'critical' crack is defined as a crack that envelopes the effects of other cracks in a specific area. ONS evaluates all 'leakage' cracks in a specific area against Giambusso requirements. In addition, the revised outside containment ONS HELB criteria do not use "Leak Before Break" (LBB) methodologies. Therefore, all ONS cracks are 'leakage cracks'.

Part C: The basis for the inside pipe diameter for a "Through-Wall Crack" comes from a common sense understanding of pressure forces, where the inside diameter is used for development of internal pipe pressure forces and stresses. In addition, due to a lack of guidance at that time, ANSI/ANS-58.2-1988 was reviewed, and page 5, paragraph 4.2.4 states (paragraph is not related to issues with jet shapes):

"A through wall crack shall be assumed to be a circular orifice through the pipe wall of cross-sectional flow area equal to the product of one-half the pipe inside diameter and one-half the pipe wall thickness."

Finally, the crack geometry based on either an inside or outside diameter dimension would cause an inconsequential difference with respect to identifying crack target interactions.

RAI 83

By letter dated October 8, 2010 the NRC issued RAI 35[H]. The licensee responded to the RAI by letter dated December 7, 2010. In the licensee's response to the RAI 35 [H], the licensee refers to rigorously analyzed piping, once where seismic loading is included, and once where seismic loading is omitted. Please define rigorously analyzed piping, and address how it differs from piping that is not rigorously analyzed.

Duke Energy Response

Rigorously analyzed piping is piping that is analyzed with a computer model, such as Duke Energy's Superpipe Computer Program. Stresses are calculated at each piping location and qualified to specific Code allowable values, as required by ONS Piping Analysis Specification OS-

027B.00-00-0001, latest revision, Table 1. The piping could require seismic loadings or it could not, depending on the specific piping system design criteria. For example, a Duke Class F piping system has seismic loads included, where a Duke Class G piping system does not require seismic loads to be included in the design. ONS UFSAR Table 3-1 identifies those Oconee piping systems that are designed for seismic loads and those that are not.

Non-rigorous or 'Alternate' Analysis (AA) methods look at general piping routing, pipe size, design temperature and seismic spans to develop support schemes that balance deadweight, thermal expansion and seismic stresses within the pipe. These methods are generally used for small bore piping (< 1.5 NPS) and tubing runs. As long as the support spans and support locations meet the AA criteria, supporting calculations for the AA method ensures that all pipe stresses will always be within Code allowable values. No direct, location specific piping stresses are calculated during the Alternate Analysis or Handbook methods.

The ONS HELB criteria address the effects of breaks and cracks for piping down to 1.5 inches NPS.

RAI 84

Concerning the application of NUREG/CR-2913, "Two Phase Jet Loads" (ADAMS Accession No. ML073510076), provide the following information:

Since NUREG/CR-2913 applies to breaks, provide justification for applying this NUREG to cracks.

The assessment should be site-specific (i.e., the indicated 10-pipe diameters may not provide a large enough zone of influence for potentially affected systems, structure, and components (SSCs).

Duke Energy Response

Duke Energy agrees that NUREG/CR-2913 was initiated for the determination of jet impingement effects following a high energy line break. However, Duke Energy requests NRC approval to use the NUREG for determination of the effects from critical cracks.

The NUREG provides an analytical model for predicting two-phase, water jet loadings on axisymmetric targets. Input to the model includes the initial system pressure, temperature (or alternatively steam quality), diameter of the break opening, distance to the target, and radius from the centerline of the target. The model ranges in application from 60 bars (870 psi) to 170 bars (2465 psig) pressure and 70 degrees Centigrade (158 degrees Fahrenheit) subcooled liquid to 0.75 (or greater) steam quality.

Giambusso/Schwencer defines critical cracks as 1/2 the pipe diameter in length and 1/2 the wall thickness in width. Giambusso/Schwencer does not provide any direction on the methodology to be used to determine potential impingement effects from critical cracks. In absence of additional guidance, Duke Energy chose to use NUREG/CR-2913 to define the zone of influence from critical cracks.

The NUREG was applied to those high energy systems that were rigorously analyzed (using a computer model) and included seismic loading. Cracks were postulated where the calculated stress exceeded $0.4(S_A + S_h)$.

The only high energy systems which had calculated stresses that exceeded the crack threshold were the Main Steam and Main Feedwater systems, thus critical cracks were postulated. For the Main Steam system the locations where the stresses exceeded the crack threshold were limited to the Turbine Building of all three Units. For the Main Feedwater system the locations where the stresses exceeded the crack threshold were in both the Turbine Building and the East Penetration Room of the Auxiliary Building of all three units. The operating pressure and temperatures for the Main Steam and Main Feedwater systems fall within the pressure and temperature ranges described in the NUREG.

Since no guidance for the determination of the zone of influence for critical cracks was promulgated in Giambusso/Schwencer and there is no description of the methodology used for the determination of the zone of influence for critical cracks in the original HELB report MDS OS-73.2, the use of the NUREG in the manner described represents a change to the ONS licensing basis for HELB. In absence of definitive studies of the zone of influence for critical cracks, the NUREG provides a reasonable methodology that can be adapted for critical cracks.

RAI 85

In the June 29, 2009, HELB LAR, the licensee stated the following:

Thrust Loads for evaluating potential interactions between postulated HELBs and the Turbine Building structural components will be determined in accordance with ANSI 58.2.

NUREG-0800, 3.6.2, Revision 2 – March 2007, page 9 states:

The ANSI/ANS 58.2 standard has been accepted by the NRC. However, based on recent comments from the Advisory Committee on Reactor Safeguards (ACRS) (V. Ransom and G. Wallis), it appears that some assumptions related to jet expansion modeling in the ANSI/ANS 58.2 standard may lead to nonconservative assessments of the jet impingement loads of postulated pipe breaks on neighboring SSCs.

Please address how these statements regarding the potential nonconservative assessments of jet impingement loads has been addressed or considered.

Duke Energy Response

The original 1973 HELB submittal (MDS OS-73.2) did not include the methodology to which HELB thrust forces and jet impingement loads were calculated. Thrust forces for systems normally in operation and for systems not normally in operation were listed in Tables 2.1-1 and 2.1-2 respectively in the MDS OS-73.2 report. However the methodology used to determine these forces is not included. In addition, the submittal did not include information relative to the jet lengths originating from a high energy line break or crack. A review of the report indicates that 'line of sight' systems and components were assumed to be not available for event mitigation following the postulated high energy line break or crack.

One of the reasons for submitting a new design basis for HELB was to provide sufficient documentation on the bases for break/crack postulation, determination of pipe whip and jet impingement loads, jet impingement lengths, and determination of mitigation strategies that were unclear in the 1973 submittal (MDS OS-73.2). The reason for including this documentation was to provide a HELB design basis that would stand the test of time. Since the methodology for the calculation of pipe whip and jet impingement loads and the calculation of jet length was unclear in the original HELB submittal, these methodologies were included in the new HELB submittal for completeness of the documentation effort.

In the revised ONS HELB licensing basis, the initial and steady state thrust forces were calculated in accordance with Appendix B of ANSI/ANS 58.2. Appendix B provides a simplified methodology for calculation of fluid thrust forces based on various publications by Shapiro, Henry, Fauske, and Moody. A review of this Appendix indicates that it was not considered a part of ANSI/ANS 58.2 per the American Nuclear Society. A note to that effect is given below the Appendix B title on page 35 of the standard.

Per the Appendix, the initial thrust force is calculated as the product of the operating pressure and inside area of the piping. The steady state thrust force is calculated similarly, except a steady state thrust coefficient is applied to the product of the operating pressure and inside area of the piping. The numerical value of the steady state thrust coefficient is a function of the fluid state of the high energy system prior to break occurrence.

As predicted by Moody, the Appendix notes that the maximum steady state thrust coefficient is 1.26 for a saturated-superheated steam system (Equation B-4 on pg. 38 of the standard). This maximum thrust coefficient was applied to all Main Steam line breaks postulated in the revised ONS HELB licensing basis. As stated, it is unclear what methodology was used in the original HELB report (MDS OS-73.2) for determining HELB thrust forces. A comparison of thrust forces following a postulated break in the 36" Main Steam line is as follows (The steady state thrust coefficient was back calculated from the MDS OS-73.2 thrust force):

Report	Operating Pressure (psig)	Inside Area of MS pipe	Initial Thrust Force (lbs.)	Steady State Thrust Force (lbs.)	Computed steady state thrust coefficient
MDS OS-73.2	914	917.13	838,257	1,230,000	1.467
HELB LARs	914	917.13	838,257	1,056,204	1.26

While the initial thrust forces are identical, the steady state thrust force calculated in the revised ONS HELB licensing basis is approximately 14% less than that calculated in the MDS OS-73.2. The difference appears to be based on the differences in the applied steady state thrust coefficient, based on a back calculation of that variable. However, the overall methodology for determining steady state thrust forces appears to be the same.

As predicted by Henry and Fauske, the Appendix notes that the steady state thrust coefficient for a frictionless subcooled system varies from 1.26 to 2.0. However, if frictional losses are taken into account the thrust coefficient varies from approximately 0.2 to 1.65. The frictional losses are calculated as fL / D, where f is the friction factor and L is the length of the piping with a diameter of D. The frictional losses are calculated from the source of the fluid (typically a pump or tank) for each segment of piping with a particular diameter to the postulated break location. These losses are then summed to determine the overall friction loss. The thrust coefficient is then determined based on the stagnation enthalpy of the piping system at the postulated break location and the overall friction loss (See Fig. B-7 of Appendix B). As such, the thrust coefficient varies with the distance of the postulated break from the source and the internal pressure and temperature of the piping system at the postulated break location. The table below shows the computed steady state thrust coefficient from the MDS OS-73.2 report:

Report	Operating Pressure (psig)	Inside Area of MFDW pipe	Initial Thrust Force (lbs.)	Steady State Thrust Force (lbs.)	Computed steady state thrust coefficient
MDS OS-73.2	1043	365.15	380,851	174,900	0.459

Since the computed steady state thrust coefficient is less than 1.0, it appears that frictional losses were used in the original HELB licensing basis to determine steady state thrust forces.

In the revised HELB licensing basis frictional losses were calculated for subcooled systems, such as the Main Feedwater system, and used to the determine steady state thrust coefficient and steady state forces. This methodology is consistent with that used in the original MDS OS-73.2 report.

Following calculation of the initial and steady state thrust forces, the jet expansion shapes were determined in accordance with NUREG/CR-2913. In those cases where surveys indicated that structures would be impacted by the jet, the jet impingement load was calculated in accordance with NUREG/CR-2913 and used to evaluate the structural component. In those cases where surveys indicated that a component was impacted by the jet, the component was assumed lost for mitigation purposes, thus it wasn't necessary to calculate the impingement load.

The portions of ANSI/ANS 58.2 regarding assumptions related to jet expansion modeling that may lead to un-conservative assessments of jet impingement loads from postulated pipe breaks on SSCs located in the zone of influence were not used in the revised ONS HELB licensing basis. Duke Energy used the simplified methodology documented in Appendix B of ANSI/ANS 58.2 for determination of initial and steady state thrust forces. Based on the discussion above, this approach appears to be similar to that used in the original HELB licensing basis. Duke Energy proposes to use the jet expansion characteristics and impingement loading methodology documented in NUREG/CR-2913. This proposed change represents a change to the ONS HELB licensing basis.

RAI 86

Please address whether containment penetrations have been analyzed for the jet impingement and pipe whip loads associated with breaks outside the containment pressure boundary in the associated penetrating lines.

Duke Energy Response

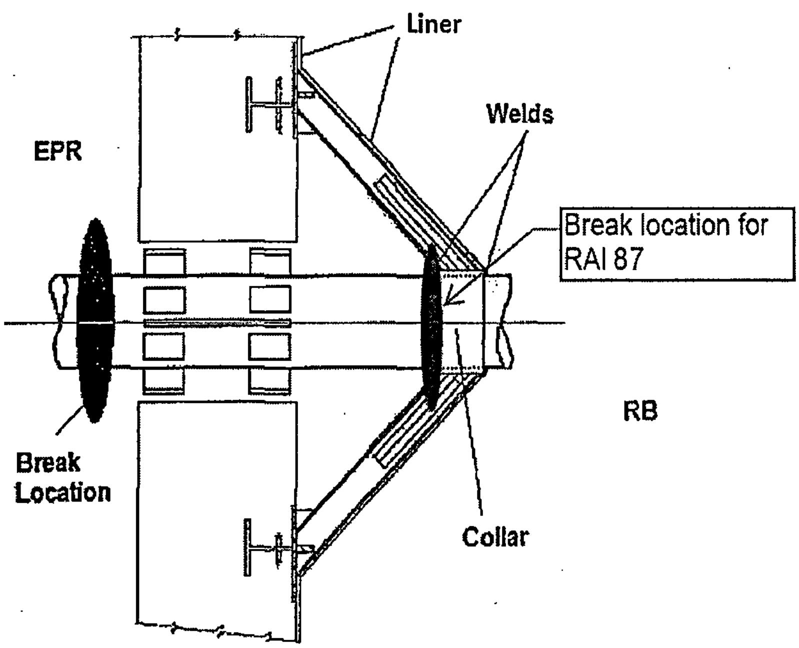
Per UFSAR Section 3.6.1.1 (2), "All penetrations are designed to withstand line rupture forces and moments generated by their own rupture as based on their respective design pressures and temperatures." This is interpreted to mean that each ONS containment penetration is designed for a postulated rupture of the piping running through that penetration. The postulated rupture could be either inside or outside containment. However, the postulated rupture would be adjacent to the anchor point of the penetration. Since the focus of the HELB LAR is for high energy line breaks outside containment, the location of the postulated terminal end breaks at the containment penetrations are outside of the concrete envelope of the reactor building. The locations were previously documented in the original HELB submittal (MDS OS-73.2) and these locations remain the same in the revised ONS HELB licensing basis. Jet impingement loads on each penetration would be bounded by individual line rupture loads given the distributed load characteristic associated with the jet expansion and the small area of the penetration(s). Duke Energy does not propose a change to the HELB licensing basis regarding the ability of the containment penetrations to withstand line rupture forces and moments created by their own rupture nor the locations of postulated piping ruptures at containment penetrations.

RAI 87

It is not clear in the licensee's October 23, 2009, response to RAI 10 how the containment liner was evaluated for jet impingement and pressurization loads resulting from the break depicted in the RAI response.

Please address whether the potential attenuation of loading, due to the presence of the reactor building wall between the break and the liner, was credited for in the evaluation.

Discuss a postulated terminal end break outside the containment boundary on the main steam anchor (see sketch below), and evaluate the effect that this break will have on the containment integrity or provide a technical justification why such a break is not required to be postulated.



Sketch RAI-87

Duke Energy Response

The postulated break location of the Main Steam line outside of the Reactor Building in the East Penetration Room (EPR) was originally postulated in the 1973 HELB report. The Atomic Energy Commission accepted and approved this location. The 1973 report (Table 2.3-1) did not note any damage to the reactor building structure for this break. Apparently, a qualitative assessment was performed supporting the 1973 report conclusion that no damage would occur to the Reactor Building concrete wall. The revised HELB license amendment requests in 2008 & 2009 did not consider the damage potential as significant, given the combination of the distributed load from the jet expansion and the inherent strength of the reactor building wall. Thus no formal analysis was completed.

The Giambusso/Schwencer requirement was to analyze the effects of postulated high energy line breaks outside containment. The ONS UFSAR Section 3.1.10 criterion 10 notes that containment is provided by the Reactor Building. The Reactor Building includes the post tensioned concrete structure and the liner. ONS UFSAR Section 3.8.1 notes that the concrete/steel containment is referred to as the Reactor Building. ONS UFSAR Section 3.8.1.1 notes that the containment structure consists of a post-tensioned reinforced concrete cylinder and dome connected to and supported by a massive reinforced concrete foundation slab. The entire interior surface of the structure is lined with a ¼ inch thick welded ASTM A36 steel plate to assure a high degree of leak tightness.

Thus the Main Steam break originally postulated in the 1973 HELB report, and postulated in the revised HELB submittals in 2008 & 2009 is the appropriate location, given that it is immediately outside the containment building (Reactor Building). This does not represent a change to ONS HELB licensing basis.

RAI 88

Attachment 2 of the June 26, 2008, LAR concerning tornado mitigation strategies proposed changes to the updated final safety analysis report (UFSAR Section 3.5.1.3.1), second paragraph states: "...This is an updated version of the original TORMIS code developed for the Electric Power Research Institute (EPRI)..." The NRC staff reviewed and approved the tornado missile risk analysis (TORMIS) code developed for EPRI in a 1983 Safety Evaluation Report (SER) for use in demonstrating compliance with the Standard Review Plan (SRP). The NRC staff has not reviewed the updated version of the TORMIS code and cannot conclude the 1983 SER is applicable.

Provide a tabulation of all differences between the original TORMIS analysis that was reviewed by the NRC and is the subject of the 1983 SER and the updated version of the TORMIS code used in the license amendment request. Provide a basis for concluding that the 1983 SER is applicable to the modified version of the TORMIS code.

Duke Energy Response

The TORMIS95 code used by Duke Energy is an updated version of the TORMIS code reviewed and approved by the NRC. It was modified to facilitate analysis for plant-specific studies rather than generic studies and research. These changes were developed by the original code developer, Applied Research Associates, Inc (ARA), and documented in various ARA TORMIS reports since TORMIS was approved in 1983 until 1995.

Duke Energy has reviewed these changes and found that the fundamental calculations used to model the transport of potential missiles, evaluate target impact, and estimate damage frequencies have not changed. In general, the changes were implemented to accomplish the following:

- Simplify code input (particularly in the area of missile data),
- Automate certain simple calculations previously performed outside the code,
- Improve output and report options, and
- Update programming to run on current computer systems.

In addition, when Duke Energy acquired the TORMIS95 code a software quality assurance evaluation was performed to verify proper operation of the code. This evaluation included an analysis run of a sample problem originally supplied by EPRI with the original code. This comparison showed that the TORMIS95 sample problem results matched exactly the results provided by the approved 1983 version of TORMIS.

Therefore, Duke Energy has concluded that the tornado missile analysis methodology approved by the NRC in 1983 is maintained in the TORMIS95 code used by Duke Energy.

RAI 89

Enclosure 2 of the June 26, 2008, Tornado LAR, Section 5.2.13 (page 31), states:

UFSAR Section 10.4.7.3.6...describes that a PRA [probalistic risk assessment] was developed to address the plant's capability to provide SSDHR [secondary side decay heat removal] via EFW [emergency feed water], SSF [standby shutdown facility] ASW [auxiliary service water], and Station ASW (see UFSAR Section 10.4.7.3.8) in the event of a tornado. As concluded in the accompanying SER, the SRP probabilistic criterion was met based on the probability of failure of the EFW and Station ASW systems combined with the protection against tornado missiles afforded by the SSF ASW System.

UFSAR Section 10.4.7.3.6 states in part "...Reference 3 concludes that the Standard Review Plan probabilistic criteria is met based upon the probability of failure of the ESW and station ASW Systems combined with the protection against tornado missiles afforded the SSF ASW System."

Reference 3 is "ONOE [Oconee Nuclear Operating Experience] -11376, changes to support multiple unit alignment to the Auxiliary Steam Header." The NRC staff believes the correct reference is "Reference 7 NRC Safety Evaluation Report on the Effect of Tornado Missiles on Oconee emergency feedwater (EFW) Systems, dated July 28, 1989 (ADAMS Accession No. 8908030311)."

The NRC staff has previously addressed the use of the 1989 SER. Specifically, RAI-11, response transmitted by letter dated September 2, 2009, and RAI 2-1, response transmitted by letter May 6, 2010, both indicated that the probability analysis submitted by the licensee did not meet the SRP 2.2.3 criteria of 10^{-6} per year. The SER stated the acceptance of the licensee's position being reviewed at that time was based on factors other than the probability analysis. As written UFSAR 10.4.7.3.6 can be interpreted to mean that the referenced SER (Reference 7 in UFSAR Section 10.4.9) approved the probability analysis prepared by the licensee. The NRC staff finds this unacceptable.

Provide the following information concerning this issue.

- What is Reference 3 is as discussed in UFSAR 10.4.7.3.6?
- Delete the reference to the 1989 SER where it can be interpreted as approving the probability analysis prepared and submitted to the NRC at that time. Also, the licensee is requested to identify and delete all references to the 1989 SER in other licensing basis documents where

the reference can be interpreted as implying that the NRC staff approved the probability analysis. The licensee is also requested to provide proposed revised UFSAR pages where the reference currently resides.

Duke Energy Response

I. Reference 3 (ONOE-11376) ["ONOE is defined as Oconee Nuclear, Oconee Exempt"] is a minor modification that addresses changes to support multiple unit alignment to the Auxiliary Steam Header [Ref. UFSAR pages 10.3-2 and 10.4-21].

II. Duke Energy conducted a licensing basis document search and found two (2) instances where there was inappropriate wording regarding the basis for the Staff approving Duke Energy's response to the TMI EFW action item (UFSAR Sections 10.4.7.3.6 and 3.2.2(4). The actions to correct these items have been captured in Duke Energy's corrective action program under PIP O-09-5977. Referenced UFSAR pages 10.4-19 and 3.2-4 are shown below:

startup path should remain available. However, if this path were unavailable, the SSF ASW System provides an alternate means of establishing feedwater flow to the unaffected SG. Prior to cooling the unit down to DHR conditions, one RCP per loop is tripped, further reducing the demand for EFW. The flowrate and inventory demands for EFW following a SGTR event is bounded by the demand for EFW following a loss of main feedwater with offsite power available.

If the EFW flow control valve on the unaffected SG fails open (on a loss of compressed air and nitrogen), this could result in the SG overcooling. The safety analyses assume action outside the Control Room for local manual control of the EFW control valve if the valve failed open. The EFW flow control valves are located in the penetration room adjacent to the Control Room.

10.4.7.3.5 EFW Response Following a MHE

The EFW pumps are located in the basement of the Turbine Building and are therefore, subject to complete failure as a result of flooding caused by a rupture of the non-seismic portion of the condenser circulating water line. In such an event, the SSF ASW System would be relied upon for shutdown decay heat removal. The SSF ASW System is not single failure proof. Penetration seals and waterproof doors have been installed between the Turbine Building and Auxiliary Building in each unit to provide waterproofing up to a height of twenty feet above the Turbine Building basement floor. Thus the High Pressure Injection (HPI) System, located in the Auxiliary Building, would be available as an alternative to the EFW System and the SSF ASW System for shutdown decay heat removal (Reference 6).

As defined in Reference 6, Oconee was deemed to meet the criteria of Generic Letter 81-14 regarding adequate post-seismic event decay heat removal capability by:

1. requiring portions of the EFW System (defined in UFSAR Section 3.2.2) to be capable of withstanding a MHE, and
2. providing alternative seismically qualified means of decay heat removal with the SSF ASW System and the HPI System.

Changed Reference 3 to 7

10.4.7.3.6 EFW Response Following a Tornado

~~A probabilistic risk assessment was developed to address the plant's capability to provide secondary decay heat removal via the EFW, SSF ASW, and station ASW Systems (see Section 10.4.7.3.8) in the event of a tornado.~~ Reference ~~3~~ concludes that the Standard Review Plan probabilistic criterion is met based upon the probability of failure of the EFW and station ASW Systems combined with the protection against tornado missiles afforded the SSF ASW System.

10.4.7.3.7 EFW Response Following a SBO

This event is similar to the LMFW with LOOP analysis with the additional assumption that the onsite emergency AC power sources have been lost. This results in the loss of the MDEFWPs. The TDEFWP should be available for 2 hours during this event because of its AC power independence. The SSF ASW System; however, is credited to remove the decay heat in this event. The SBO event, which is not a design basis event, is described in UFSAR Section 8.3.2.2.4.

10.4.7.3.8 Initiation of SSF ASW, Station ASW, and HPI Forced Cooling

The SSF ASW System, station ASW System, and HPI forced cooling serve as alternate means of decay heat removal for some of the EFW design events described in Section 10.4.7.3.

Once the control room decides to use the SSF ASW system, the system can be aligned within 14 minutes, consistent with the assumptions in the safety analyses. The SSF ASW flow rate provided to each unit's steam generators is controlled using the motor operated valves on each unit's SSF ASW supply header.

CCW intake piping. Redundant and diverse sources of secondary makeup water are credited for tornado mitigation. These include: 1) the other units' EFW Systems, 2) the ASW "tornado" pump, and 3) the SSF ASW pump.

Protected or physically separated lines are used to supply cooling water to each steam generator. One of the six sources of electric power for the pump is supplied from Keowee Hydro Station.

An external source of cooling water is not immediately required due to the large quantities of water stored underground in the intake and discharge CCW piping. The stored volume of water in the intake and discharge lines below elevation 791ft would provide sufficient cooling water for all three units for approximately 37 days after trip of the three reactors.

Although not fully protected from tornadoes, the following sources provide reasonable assurance that a sufficient supply of primary side makeup water is available during a tornado initiated loss of offsite power.

a. The SSF Reactor Coolant Makeup Pump can take suction from the Spent Fuel Pool. The pump can be supplied power from the SSF Diesel.

b. A High Pressure Injection Pump can take suction from either the Borated Water Storage Tank or the Spent Fuel Pool. Either the "A" or "B" High Pressure Injection Pump can be powered from

upon the probability of failure of the EFW and Station ASW systems combined with the protection against tornado missiles afforded by the SSF ASW system,

Vater Pump Switchgear.

design criteria, similar to the criteria to protect against phenomena described in UFSAR section 3.1.2. A specific ulated, nor is all equipment that would be used to bring the isted. The statement, "Capability is provided to shutdown ualitative assessment that, after a tornado, normal shutdown stems will be available to allow shutdown of the plant. It was not intended to imply that specific systems should be tornado-proof. As part of the original FSAR development, specific accident analyses were not performed to prove this judgement, nor were they requested by the NRC. Subsequent probabilistic studies have confirmed that the original qualitative assessments were correct. The risk of not being able to achieve safe shutdown after a tornado is sufficiently small that additional protection is not required.

In addition, there was considerable correspondence between Duke and NRC in the years post-TMI discussing Oconee's ability to survive tornado generated missiles. Based ~~primarily on PRA justifications,~~ the NRC concluded that the secondary side heat removal function complied with the criterion for protection against tornadoes.

3.2.2.1 System Classifications

Plant piping systems, or portions of systems, are classified according to their function in meeting design objectives. The systems are further segregated depending on the nature of the contained fluid. For those systems which normally contain radioactive fluids or gases, the Nuclear Power Piping Code, USAS B31.7 and Power Piping Code USAS, B31.1.0 are used to define material, fabrication, and inspection requirements.

Diagrams for each system are included in the FSAR sections where each system is described.

Fabrication and erection of piping, fittings, and valves are in accordance with the rules for their respective classes. Welds between classes of systems (Class I to II, I to III, or II to III) are performed and inspected in accordance with the rules for the higher class. This preceding sentence does not apply to valves where the class break has been determined to occur at the valve seat, and to pipe with 1" nominal diameter and less.

RAI 90

Attachment 2 of the June 26, 2008, Tornado LAR, the proposed change to UFSAR Section 3.5.1.3.1, last paragraph, states: "...the mean annual frequency of a damaging tornado missile strike resulting in a radiological release in excess of [Title 10 of the *Code of Federal Regulations* Part 100] 10 CFR 100 limits was determined to be less than the acceptance criteria of 1E-06 based on the Oconee tornado hazard data (Reference 14)." The cited reference has been withheld from public disclosure at the request of the licensee. By withholding this from public disclosure, the numerical results of the analysis are not contained in the UFSAR.

Provide the results of the analysis that demonstrate compliance with the acceptance criteria of 1E-06.

Duke Energy Response

The results for all three Oconee Units demonstrate compliance with the acceptance criteria of 1E-06, and are listed below:

Unit 1 - 6.8E-07 per year (from Reference 13 of UFSAR Markup)
Unit 2 - 6.3E-07 per year (from Reference 12 of UFSAR Markup)
Unit 3 - 9.0E-07 per year (from Reference 11 of UFSAR Markup)

RAI 91

In the June 26, 2008, Tornado LAR, Section 5.3 of Attachment 4 (page 8), under SSF South Double Door states: "Various thicknesses of steel plating...to be the appropriate minimum thickness required to produce acceptable damage frequency results." The NRC staff is not familiar with the term acceptable damage frequency results. Define the term acceptable damage frequency results, and provide any references where the term is used in NRC regulations or guidance.

Duke Energy Response

Duke Energy will design and install a missile shield to protect the SSF South Double Door. The shield design will be deterministic and will not employ varying steel plating thickness to produce acceptable damage frequency results. The shield will be designed for the missiles described in Regulatory Guide 1.76, Rev. 1 in accordance with Section 9.6.3.1 of the Oconee UFSAR. The shield will be a QA-1 structure and will be designed in accordance with the applicable codes and standards listed in Table 9-19 of the Oconee UFSAR. Ultimate strength concepts will be used in the design of the shield. Construction of the shield will be completed by December 31, 2013.

RAI 92

In the June 26, 2008, Tornado LAR, Section 4, 2nd section of Attachment 4 states: "Note that these missiles include debris from structures that are expected to fail due to tornado winds." Provide a list of structures that are expected to fail due to tornado winds that are included as sources of tornado missiles.

Duke Energy Response

The following is a list of structures from Table B-1 of Duke Energy Calculation OSC-8859 ("Oconee Tornado Missile Inventory") that are expected to fail due to tornado winds and are included as sources of tornado missiles. Some of these structures will only experience partial failure due to tornado winds.

- Unit 1 Turbine Building
- Unit 2 Turbine Building
- Unit 3 Turbine Building
- Hot Machine Shop
- HP Building (RP Office Area)
- Warehouse #5-Tool Storage
- Maintenance Support Building
- Administration Building/Service Building
- Oconee Office Building
- Warehouse #6
- Contaminated Storage Warehouse
- "Old Blue" Office Building
- Warehouse #3/Fabrication Shop
- Essential Siphon Vacuum Building
- Interim Radwaste/Shredder Building
- Insulation Shop/Scaffold Storage Building
- Oil Drum Storage Building
- RCP Refurbishment Building
- Radwaste Facility
- 230kV Switchyard Relay House
- Welding/Fabrication Shop
- 525kV Switchyard Relay House
- Maintenance Training Facility
- Oconee Garage
- Oconee Training Center
- World of Energy Visitors Center
- Old Bahnson Building
- Cable Storage Warehouse
- ISFSI Equipment Storage Building
- Microwave House
- Technical Support Building
- Office Trailers.

RAI 93

In the June 26, 2008, Tornado LAR, Attachment 4, Section 5.1 states "With the modifications associated with the LAR, Oconee will have 2 redundant systems credited for secondary-side decay heat removal (SSDHR) which are the SSF ASW and the PSW system (enhanced replacement for the original Station ASW system)." In order to be considered "redundant" the two systems must be available at the same time. The PSW system is potentially not available for the first 72 hours. Since the PSW system may not be available after a tornado event, provide the justification how 2 redundant systems are credited for SSDHR.

Duke Energy Response

Duke Energy agrees that the use of the word "redundant" in this context was inappropriate and plans to revise the wording as part of the repackaging of the Tornado LAR.

Duke Energy believes that the PSW system will remain functional following most tornado strikes to the station. Historically, between 1950 and 2005, the majority of recorded tornado intensities in the 5-state Oconee subregion have been in the EF0 (65-85 mph) to EF1 (86-110 mph) range. In addition, the portions of the PSW system that are not deterministically protected are located in areas of the Auxiliary Building that affords physical protection, but not to current industry standards.

RAI 94

In Attachment 4, of the June 26, 2008, LAR, Section 5.2 identifies three SSCs as having redundancy and that are evaluated "qualitatively," i.e., not included in the cumulative probability results. The results of the ONS TORMIS analysis are reported in Table 5 as 6.8/6.3/9.0E-07 for Units 1, 2 and 3 respectively. In an NRC memorandum to V. Stello from H. Denton, "position on Use of Probability Risk Assessment in Tornado Missile Protection Licensing Actions," dated November 7, 1983 (ADAMS Accession No. 080870291), the staff states:

This guidance, which we will use in our probabilistic tornado missile reviews, states that an expected rate of occurrence of potential exposures in excess of the 10 CFR 100 guidelines of approximately 10^{-6} per year is acceptable if, when combined with reasonable qualitative arguments, the risk can be expected to be lower.

Given the narrow margin between the cumulative probabilities reported in the LAR and the acceptance criteria, the staff finds the omission of the probability of these, and other targets that are qualitatively assessed, questionable when one considers what is stated in the November 7, 1983 memo cited above.

Provide a basis for concluding that with reasonable qualitative arguments, the risk can be expected to be lower.

Duke Energy Response

Section 5.2 of Attachment 4 of the LAR was intended to document three specific target sets which required special treatment due to special circumstances rather than to imply that they were excluded from the scope of the TORMIS evaluation. These special circumstances include instances where functional redundancy, physical separation, and other qualitative considerations were taken into account, or where limitations of the TORMIS computer code prevented the development of a suitable model to evaluate the targets. Additional qualitative information and clarifications was provided for these target sets in the response to RAI #14 submitted to the NRC in a letter dated September 2, 2009.

One particular problem is that the inherently low damage probability characteristics for these targets make it difficult to successfully obtain an adequate sample size to establish a precise estimate of the low probability value. Out of this group, the target set most suitable for more detailed analysis is the Main Steam Support pedestal columns. To provide additional justification that the damage contribution is negligible, additional analysis runs were made for two of the Unit 3 columns to increase the sample size by approximately a factor of 10. The results showed a damage probability of 2.4E-10 for the outer pair of columns. Considering all combinations of columns, the total damage contribution for the Unit 3 pedestal columns is estimated to be approximately 7E-10 per year.

In view of the Unit 3 total damage probability of 8.96E-07 /year (from Table 12 of Calculation OSC-8860 Rev. 3) the additional contribution of the pedestals represents a negligible increase of less than 0.1%. Given that the spacing of the Unit 1 and Unit 2 pedestal columns is the same as Unit 3, it is expected that the probability of concurrent damage on multiple columns is also negligible and do not need to be quantified explicitly. Unit 1 and Unit 2 also have greater analysis margin than Unit 3 since their total missile damage probabilities are 6.8E-07 /year and 6.3E-07 /year, respectively.

The confirmation that the damage probability of pedestal columns is negligible is also judged to support the qualitative evaluation of the other target sets. This is because the spacing between the SSF Trench Vents and the CCW piping is greater than the spacing between the pedestal columns which is considered to reduce the likelihood of damage to multiple targets at the same time. Thus, it can be concluded the probability of damage to these other targets is bounded by the damage probability of the pedestal columns, and that the overall contribution of these targets is also negligible.

Another factor that was identified for the SSF trench vents is that they are located immediately in front of the newly installed steel barriers on the West Penetration Room/Cask Decon Room walls. These steel barriers are not rated for vehicle missiles and are included as safety targets in the TORMIS model. As a result, the majority of damaging missile impacts to the vent pipes are already being effectively counted as damage events against the shield barriers. Thus, the vent pipes do not add any significant damage contribution to the overall damage probability even before redundant vent paths are considered.

In conclusion, the omission of the specific quantitative results for this limited set of qualitatively evaluated targets does not adversely impact the overall plant damage result. Therefore, the TORMIS acceptance criterion is met since the quantitative results are less than 1E-06 per year and reasonable qualitative arguments have been presented in Section 4.4.2 of Enclosure 2 of the Tornado LAR to demonstrate that the actual risk can be expected to be lower. Specifically:

- No credit was given for the availability of PSW System for accident mitigation.
- A conservative estimate of the site tornado hazard was used for the analysis.
- A conservative estimate of the site missile inventory was used for the analysis. The entire site missile population is treated as being minimally restrained. The missile injection model used by the TORMIS code is designed to release potential missiles into simulation windfield at the point in time that would lead to maximum transport resulting in conservative estimates of impact and damage probabilities.
- Due to limitations in modeling the trajectory of missiles, the code is unable to account for the interactions of missiles with Auxiliary Building concrete beams and columns. A small adjustment was made for very long missiles which can span between these beams. However, the effect of off-set missile hits for missile types could be significant in the

prevention of missile impacts on safety targets inside the WPR and EPR and represents a conservative analysis assumption.

- No credit was taken for the substantial number of interferences inside in the East and West Penetration Rooms from other piping systems, electrical conduits & cable trays, hangers and steel supports, platforms, handrails, and ventilation ductwork. These rooms are in fact quite congested and would likely dissipate and stop most missiles from damaging critical equipment in the rooms. This "congestion" is in part why modifications inside the room to protect these specific pieces of equipment are not practical or feasible.
- The treatment of the Turbine Building is conservative in that it (1) minimizes the shielding effects that it would provide with its massive superstructure and metal siding, and (2) optimizes the availability of potential missiles located on the turbine deck for injection into the tornado windfield.
- No credit is given for SSF cables surviving a missile impact at any velocity. The horizontal cable trays provide a reasonable amount of protection in the horizontal direction, plus the cables themselves are armored-jacketed cables which are much more rugged than ordinary power plant cable.

The results show that with the planned modifications most of the risk contribution is attributable to the SSF cable trays in the WPR. The SSF cables are relatively "soft" targets which cover a significant area. However, as noted above, no credit is given for the interferences in the room which would dissipate the energy of most missiles and prevent their transport across the room to the SSF cables. Considering these qualitative factors and the availability of PSW for tornado mitigation, the actual risk of missile damage is less than the quantified analysis value.

RAI 95

Attachment 4 of the June 26, 2008, LAR conclusions, states [page 15]: "...Considering these sources of conservatism, especially the availability of PSW for tornado mitigation..." The NRC staff understands that PSW electrical distribution system can be damaged and would need to be repaired in the first 72 hours.

Explain how the PSW is considered a conservatism if the PSW system can be damaged by a tornado.

Duke Energy Response

Duke Energy believes that the PSW system is a conservatism in that, although the PSW system is not completely protected from the damaging effects of a severe tornado, it is likely to remain functional following most tornado strikes to the station.

Historically, between 1950 and 2005, the majority of recorded tornado intensities in the 5-state Oconee subregion have been in the EF0 (65-85 mph) to EF1 (86-110 mph) range. In addition, the portions of the PSW system that are not deterministically protected are located in areas of the Auxiliary Building that affords physical protection, but not to current industry standards.

RAI 96

By letter dated May 25, 2010, the NRC issued RAI 2-29. The licensee's response to RAI, by letter dated June 24, 2010.The RAI response states that the average tornado warning time is 13 minutes, based on National Weather Service data.

Please provide a reference citation or description of the tornado warning time which includes the methodology and inputs used to estimate the warning time.

Please provide the bases for use of an average warning time and the margins of uncertainty.

Duke Energy Response

The official NOAA website states that the average warning time for tornadoes is 13 minutes (http://www.noaa.gov/features/protecting/tornados101.html). At Duke Energy's request a query was made by the staff in the Greer, SC NOAA office of the Storm-based Severe Weather Warning Verification database (inaccessible to the general public) and verified the average lead time since October 2007 to be 13.0 minutes.

The following documents were also reviewed by Duke Energy and found to support the 13 minute average warning time:

- NOAA's Warn-on-Forecast Project Plan (http://www.nssl.noaa.gov/projects/wof/documents/WoF_Project_Plan_2010.pdf), and
- Bieringer and Ray (1996) (http://journals.ametsoc.org/doi/pdf/10.1175/1520-0434(1996)011%3C0047%3AACOTWL%3E2.0.CO%3B2

RAI 97

Are all SSCs that are important to safety at ONS designed, as a minimum, to withstand either the design-basis tornado described in Regulatory Guide (RG) 1.76, Revision 0, "Design-Basis Tornado for Nuclear Power Plants," or the design-basis tornado and design-basis tornado-generated missile spectrum described in RG 1.76, Revision 1, "Design-Basis Tornado and Tornado Missiles for Nuclear Power Plants," for Region I tornadoes? In your response, please discuss whether the RG 1.76, Rev. 0, or RG 1.76, Revision 1, guidance applies to all current structures, systems, and components that are important to safety, as well as any new, or current structures, systems, and components that are modified as part of the current license amendment request. If the design-basis tornado proposed for ONS is characterized by less-conservative parameter values than specified in RG 1.76, Revision 0, or RG 1.76, Revision 1, provide a comprehensive analysis to justify the selection of the less-conservative design-basis tornado.

Duke Energy Response

No. Over its 38 year operating history, the Oconee Nuclear Station (ONS) has been licensed to three (3) tornado design bases criteria (shown below) which, depending on the vintage of the equipment, were used in the licensing process to design station structures.

(1) Class 1. Applicable to original ONS SSCs required to
   - Maximum 300 mph wind speed,

- Tornado induced negative differential pressure: three (3) psi occurring in 5 seconds, and
- Two (2) tornado missiles: (1) 8-inch diameter x 12 foot long piece of wood, 200 pounds, 250 mph, and (2) 2,000 pound automobile, 100 mph, 20 sq. ft. impact area, 25 ft above grade.

(2) RG 1.76 Revision 0 (w/exceptions). Applicable to the Standby Shutdown Facility (SSF).

- Rotational wind speed = 300 mph.
- Translational speed of tornado = 60 mph.
- Radius of maximum rotational speed = 240 ft.
- Tornado induced negative pressure differential = three (3) psi occurring in three seconds
- Tornado missiles (see table below):

Missile Descriptions	Weight (lbs.)	Impact Area (sq. in.)	Horizontal (ft/sec)	Vertical (ft/sec)
WOOD PLANK 3.62 in. x 11.37 in. x 12ft	115	41.2	272	190
STEEL PIPE 6 in. diam. 15 ft. long Schedule 40	287	34.5	171	120
STEEL ROD 1 in. diam., 3 ft. long	8.8	0.79	167	117
UTILITY POLE 13.5 in. diam., 35 ft. long	1124	143.1	180	126
STEEL PIPE 12 in. diam., 15 ft. long Schedule 40	750	127.68	154	108
AUTOMOBILE 28 sq. ft. frontal area	3990	4032.0	194	136

(3) RG 1.76 Revision 1. Applicable to future ONS design changes to SSF-related SSCs and to new systems and structures required to resist tornado loadings.

- Maximum wind speed = 230 mph.
- Translational speed = 46 mph.
- Radius of maximum rotational speed = 150 ft.
- Tornado induced negative pressure differential = 1.2 psi, occurring in 2.4 seconds (rate of pressure drop of 0.5 psi/sec).
- Maximum rotational speed = 184 mph.
- Tornado missiles (see table below):

Missile Descriptions	Weight (lbs.)	Impact Area (sq. in.)	Horizontal (ft/sec)	Vertical (ft/sec) (Note 1)
STEEL PIPE 6.625 in. diam. 15 ft. long Schedule 40	287	N/A	135	90
SOLID STEEL SPHERE 1 in. diam.	0.147	N/A	26	17
AUTOMOBILE 16.4 ft. x 6.6 ft. x 4.3 ft.	4000	N/A	135	90

Note 1: Vertical velocity is 67% of the horizontal velocity.

In March 2007, the NRC issued RG 1.76, Revision 1. The RG 1.76 design basis tornado wind speeds are chosen such that the probability of a tornado exceeding the design basis would be on the order of 10^{-7} per year per nuclear power plant. Also of note is that on page 10 of the RG, it is stated that, "*No backfitting is intended or approved in connection with its issuance*."

On October 17, 2007, Duke Energy incorporated via 10 CFR 50.59, Regulatory Guide (RG) 1.76, Revision 1, "Design-Basis Tornado and Tornado Missiles for Nuclear Power Plants," for future design changes of SSF-related SSCs and to new systems and structures required to resist tornado loadings.

The applicable tornado design criteria for the structures important to tornado mitigation are:

Structure	Applicable Tornado Design Criteria	Year Licensed (initial)
Reactor Building (RB)	Class 1	1973
Auxiliary Building (AB)	Class 1 areas given in UFSAR Table 3-23[1]; otherwise Class 2[2,3,4]	1973
Turbine Building (TB)	Class 2	1973
Standby Shutdown Facility (SSF)	RG 1.76 Rev. 0 (w/exceptions)[5]	1992, 2012 (est.) for TORMIS
Protected Service Water (PSW) Building and duct banks	RG 1.76 Rev.1	2012 (est.)
Keowee Hydroelectric Units (KHU)	Class 2	1973
Borated Water Storage Tank (BWST) and skirt enclosure	Class 1	1973

[1] All Class 1 structures, except those structures not exposed to wind, are designed for tornado loads (UFSAR 3.3.2)
[2] For Class 2 structures, the wind loads are determined from the largest wind velocity for a 100-year occurrence. This is 95 mph at the site (UFSAR 3.3.2.5)
[3] Class 2 structures are those whose limited damage would not result in a release of radioactivity and would permit a controlled plant shutdown but could interrupt power generation (UFSAR 3.2.1.1.2).
[4] East Penetration Room: contains a HELB blowout panel and is susceptible to tornado missile damage. West Penetration Room modifications comply with Rev. 1 of RG 1.76 for wind and delta-P, missiles qualitatively evaluated using TORMIS.
[5] As noted above, with some exceptions, the SSF has been designed to RG 1.76 (Rev. 0) tornado design criteria. In addition, the following are not physically protected from the effects of tornado missiles and have been evaluated probabilistically using the TORMIS methodology:

- Certain electrical penetrations and vertical cable trays in the West Penetration Room (WPR) and Cask Decontamination Tank Rooms (CDTR),
- SSF ASW piping in the WPR/CDTR (all in guard pipe except for feedwater check valves and CCW-125),
- SSF cable trench at north end of SSF building,
- SSF Diesel Service Water (DSW) Discharge Pipe (at west wall).

RAI 98

By letter dated July 6, 2009, the NRC issued RAI 15a. The licensee responded to the RAI by letter dated September 2, 2009. The RAI response states "The location of the new 100/13.8 kV substation was selected to provide wide separation from existing ONS backup power supplies to prevent coincident tornado damage of all power supplies at the same time. The 230 kV switchyard is supplied from multiple directions including 2 circuits from Jocassee (from the north) while Keowee Hydro is located east of ONS, and the new 100/13.8kV substation was placed south of ONS. There is a minimum of approximately 3,000 feet between these power supplies. Using Regulatory Guide 1.76, Revision 1, Region I data and equation 1b, the resultant wind speed at the perimeter of the 3,000 foot circle would be approximately 64 mph which is within the design capability of Oconee's power supplies."

Please explain why this scenario is the limiting case. Describe the consequences of the design-basis tornado sequentially striking the power supplies and/or the point of confluence of power lines from several directions, even if the power sources themselves are not impacted.

Duke Energy Response

The 100/13.8kV substation and the Keowee Hydro Station (Keowee) are the credited power supplies to the Protected Service Water (PSW) System. There is over 5000 feet of separation between these two independent power sources for PSW.

The 100/13.8kV substation is powered from the 100kV Black Fant line. The 13.8kV power feed cables from the substation to the PSW Building are mounted on wood poles. The power feed from Keowee to the PSW Building is protected underground and therefore unaffected by tornadoes.

The 5000 foot separation of these two power sources minimizes the possibility of a tornado striking both sources. However, should a tornado (as defined in Regulatory Guide 1.76 Revision 1) travel in a straight path that impacts both credited power sources, then the plant switchyard (including transmission lines from Jocassee), the plant Turbine Building and the CT-5 transformer will not be physically impacted.

Regulatory Guide 1.76 Revision 1 provides a means of calculating the maximum wind speed at the perimeter of the tornado path. Using formula (1b) and Table 1 in the Regulatory Guide,

$$Vt + Vr = Vt + (VRm\ Rm) / r$$

Where:

Vt = translational speed = 46 mph for Region 1
Vr = rotational speed at given radius
VRm = maximum rotational speed = 184 mph for Region 1
Rm = radius of maximum rotational speed = 150 feet for Region 1
r = radius from tornado vortex center

And the distances from the centerline of the tornado path that travels through the 2 credited power sources to the following equipment:

- 230kV Switchyard: r > 1700 feet
- Turbine Building: r > 2200 feet
- CT-5 transformer: r > 3000 feet

The corresponding wind speed at the 230kV Switchyard is 62 mph
The corresponding wind speed at the Turbine Building is 59 mph
The corresponding wind speed at the CT-5 Transformer is 55 mph

These wind speeds are well within the 95 mph design capability of these structures.

If the tornado approaches the plant from a different direction, for cases that cause damage to the plant, a similar exercise shows that at least one of the credited power sources' structure is not affected. However, depending on the direction of the tornado path, repairs to the above ground 13.8kV power feed to the PSW Building and isolation from a potentially damaged portion of the 100 kV Black Fant line may be required. Sufficient transmission crews and materials are available on the Duke Energy system to perform these repair activities during the 72 hour mission time of the Standby Shutdown Facility.

Based on the above information, the most limiting case for impact to the power supply to the PSW system is when the tornado impacts both credited power sources. In this case, PSW is not needed for mitigation, because normal plant systems are available and powered from the switchyard via the Jocassee transmission lines. Repairs to transmission towers and lines are not required. In the cases described, a power supply will be available to the PSW system within the required 72 hours, following the completion of limited damage repairs.

RAI 99

By letter date October 8, 2010 the NRC issued RAI 1 [H]. The licensee responded to the RAI by letter dated December 7, 2010. The licensee's response to the RAI, provides atmospheric dispersion factors (χ/Q values) used in the dose assessment for postulated HELBs in the letdown line.

Please provide a reference which documents the establishment of these control room (CR) χ/Q values as licensing basis values for the HELB dose assessment.
Please clarify whether the CR χ/Q values shown on page 4 would apply to the worst-case main steam line break following a tornado.

Provide a reference to any other CR χ/Q values associated with design basis accidents that may result from the occurrence of a tornado.

Duke Energy Response

The control room (CR) χ/Q values used for the HELB letdown line break event dose analysis employ the same methodology that the NRC approved for the Alternative Source Term (AST) License Amendment Request (LAR). The χ/Q associated with an ADV release point was used for the HELB letdown line break, since it is conservative relative to the HELB letdown line break release location. Bounding χ/Qs for Oconee release points (including the ADV) were previously submitted to the NRC with the AST LAR on October 16, 2001. Duke Energy received the NRC Safety Evaluation approving full-scope AST implementation for Oconee on June 1, 2004. The most current calculated χ/Q values vary slightly from those initially submitted in the October 2001

AST LAR, based on final as-built locations of Oconee's dual control room intakes installed in 2005. The most current calculated χ/Q values are reflected in UFSAR Table 15-61, shown below. Note that the values do not reflect the adjustment for the airflow split between the dual intakes reflected in the χ/Qs used in the HELB letdown line break dose analysis.

The analysis of a worst-case main steam line break following a tornado will credit steam line isolation by the Main Steam Isolation Valves (MSIVs), which will be located upstream of the current location of the Main Steam Safety Valves (MSSVs) and further from the control room intakes than the current MSSVs. Thus, the release location is expected to be less limiting than the MSSV χ/Qs shown in UFSAR Table 15-61.

The χ/Q values from UFSAR Table 15-61, adjusted as necessary for the airflow imbalance between the dual intakes, are used for design basis accidents at Oconee. Duke Energy is not asking for approval for any new CR χ/Q values for accidents that may result from the occurrence of a tornado.

Table 15-61. Control Room Atmospheric Dispersion Factors (χ/Qs)

Release Type	Bounding χ/Q (sec/m^3)
Units Vent Releases	
0 to 2 hr	9.43E-04
2 to 8 hr	6.00E-04
8 to 24 hr	2.41E-04
1 to 4 days	1.87E-04
4 to 30 days	1.54E-04
Main Steam Penetration Releases	
0 to 2 hr	5.76E-04
2 to 8 hr	4.09E-04
8 to 24 hr	1.72E-04
1 to 4 days	1.34E-04
4 to 30 days	1.08E-04
Equipment Hatch Releases	
0 to 2 hr	6.59E-04
2 to 8 hr	4.86E-04
8 to 24 hr	2.13E-04
1 to 4 days	1.65E-04
4 to 30 days	1.28E-04
ADV Releases	
0 to 2 hr	1.79E-03
2 to 8 hr	1.25E-03
8 to 24 hr	5.45E-04
1 to 4 days	4.17E-04
4 to 30 days	3.34E-04
MSSV Releases	
0 to 2 hr	1.91E-03
2 to 8 hr	1.33E-03
8 to 24 hr	5.86E-04
1 to 4 days	4.52E-04
4 to 30 days	3.54E-04

Release Type	Bounding χ/Q (sec/m^3)
MSLB Releases	
0 to 2 hr	1.21E-03
2 to 8 hr	8.39E-04
8 to 24 hr	3.70E-04
1 to 4 days	2.81E-04
4 to 30 days	2.23E-04
Fuel Handling Building Roll-up Door Releases	
0 to 2 hr	3.19E-04
2 to 8 hr	2.50E-04
8 to 24 hr	1.04E-04
1 to 4 days	7.89E-05
4 to 30 days	6.10E-05
BWST Releases	
0 to 2 hr	4.76E-04
2 to 8 hr	3.27E-04
8 to 24 hr	1.35E-04
1 to 4 days	1.05E-04
4 to 30 days	8.99E-05

RAI 100

The Design Study ONDS-351, Rev. 2, "Analysis of Postulated High Energy Line Breaks Outside of Containment" (HELB Analysis) states in Section 2.4 that single active failures will be imposed for systems required for initial event mitigation, but not for systems required to initiate plant cool down.

Are single active failures imposed on the PSW, and the SSF systems?

Duke Energy Response

No. Neither the PSW System nor the SSF System has been designed to withstand individual single active failures. As such, there is no analysis at a component level to evaluate the effects of single active failures within each system. The PSW and SSF systems serve as backups to the plant's normal and emergency systems. Should the normal and emergency systems be lost due to HELBs outside containment, either the PSW or the SSF systems could be utilized to establish safe shutdown. The PSW and SSF systems provide Oconee with two alternate methods of maintaining safe shutdown.

RAI 101

Identify postulated HELBs that are capable of damaging piping or components belonging to the PSW or SSF and support systems that enable the operation of PSW or SSF. If any HELBs that damage or prevent the PSW or SSF from functioning exist, then provide a description of the impact that loss of PSW or SSF would have in that HELB scenario. Also address whether repairs would be necessary and how such repairs could be made.

Duke Energy Response

HELBs, occurring inside the East Penetration Room (EPR), have the potential to adversely affect the pressurizer heaters that can receive power from PSW. The PSW system is not required to mitigate the consequences of the postulated HELBs occurring inside the EPR. Power to the Pressurizer Group B heaters would remain powered from its normal power source and controlled from the main control room. The loss of the remaining pressurizer heaters does not adversely affect those HELB scenarios. Plant systems remain available to enable a plant cooldown to a cold shutdown condition.

HELBs, occurring inside the Turbine Building (TB), do not damage the PSW and SSF systems. These HELBs may damage the CCW piping inside the TB. Ruptures in the CCW piping could result in flooding of the TB prompting operator action to isolate CCW inputs to the TB. The actions to isolate the CCW inputs will affect the long term available inventory in the CCW piping for use by the PSW or the SSF Auxiliary Service Water (SSF ASW) Pump. A portable pump powered from either PSW or the SSF would be utilized to pump water from the intake canal into the Unit 2 CCW inlet piping to provide long term inventory control in the CCW piping to support extended operation of the PSW pump or the SSF ASW pump. The installation and use of the portable pump for replenishment of the CCW inlet piping is addressed in existing station procedures.

RAI 102

As identified in the June 29, 2009, LAR HELB analysis, some HELB interactions result in a breach in the piping of systems required for cold shutdown. In order to proceed from the safe shutdown condition, these piping breaches would need to be repaired. For the largest piping breach resulting from HELB interaction with a cold shutdown system, provide a description of how such repairs would typically be made and an estimate of the time required to complete those repairs. Can this type of damage be repaired within the 72-hour time frame identified in the HELB Analysis?

Duke Energy Response

As described in the referenced HELB LAR, safe shutdown could be maintained for up to 72 hours utilizing the Standby Shutdown Facility (SSF) following HELBs inside the Turbine Building that could render normal plant systems unavailable. The Protected Service Water (PSW) system could enable safe shutdown capability beyond 72 hours. The PSW system and its associated electrical distribution system would also provide for a plant cooldown to approximately 250°F. There are no postulated piping failures that need to be repaired to support operation of the PSW system in maintaining safe shutdown or for plant cooldown. The referenced LAR has not imposed any time requirement for completing a plant cool down to cold shutdown. The referenced LAR identified some piping necessary for the achievement of cold shutdown that may be damaged from postulated HELBs inside the Turbine Building. Damage repair to the vulnerable piping is not required to be completed within 72 hours. A description of the vulnerable piping needed for cold shutdown is provided below.

A number of interactions were identified with piping systems required for cold shutdown. All of these interactions were created by postulated HELBs occurring inside the Turbine Building. The piping systems required for cold shutdown that may be damaged by HELBs inside the Turbine Building include the Condenser Circulating Water (CCW) and Low Pressure Service Water (LPSW) systems. The Siphon Seal Water (SSW) system supports the operation of the CCW and LPSW systems. As such, the SSW system is included as a system evaluated to determine impact to achieving cold shutdown. Piping breaches in these systems do not prevent the units from being brought to a safe shutdown condition nor do they prevent the units from being cooled down to approximately 250°F. The units can be maintained for an extended period of time at this condition using the steam generators for decay heat removal. As such, there is no established time frame for completing all damage repairs.

There are two supply headers for the SSW system. One header is supplied from the shared Unit 1 and 2 LPSW system. The second header is supplied from the Unit 3 LPSW system. SSW piping failures can occur in one or both headers. All of the postulated piping breaches in the SSW system can be isolated from the LPSW systems. However, the breaches in SSW piping results to failure of the SSW system. Damage repairs would be necessary to restore the SSW system to its normal operating configuration. However, damage repairs are not required to restore its support function to the CCW and LPSW systems. An alternate means of providing cooling water to the CCW pumps would be available. The broken SSW lines could be isolated outside the Turbine Building. A portable pump would be installed and connected to the cooling water lines to the CCW pumps at the CCW intake structure. All of the required equipment are stored onsite and installed utilizing existing station procedures.

The LPSW pumps for all units are supplied from the CCW crossover header that can be supplied by any or all of the units' CCW systems. Any one unit's CCW system, with one CCW pump operating, can supply adequate suction to the LPSW pumps. There are three LPSW pumps shared by Units 1 and 2, and two LPSW pumps for Unit 3. The LPSW system has been sub-divided into "essential" and "non-essential" headers. The non-essential headers are not required for cooldown to cold shutdown. Any postulated pipe ruptures in the non-essential header would be isolated from the essential header by manually closing an isolation valve. The essential headers are required to provide cooling water to the decay heat removal coolers to enable a plant cooldown to cold shutdown. The LPSW return from the decay heat removal coolers can be discharged to any or all units' CCW discharge piping via the "RCW Cooler Discharge Header". Any pipe breaches in the CCW crossover header, suction lines to the LPSW pumps, the essential LPSW headers that supply cooling water to the decay heat removal coolers, or the LPSW return via the RCW Cooler Discharge Header would need to be repaired to enable a unit cooldown to cold shutdown. There are several instances where a postulated HELB inside the Turbine Building may create a breach that would need to be repaired. The extent of piping repair is dependent on the postulated HELB. It should be noted that only one HELB is postulated as the event. Therefore, in assessing the scope of damage repair to piping, only one HELB event should be considered.

The following are Unit 1 HELBs that may cause repair activities to piping needed for cold shutdown:

- HELB 1-C-037-R breaks 1, 6, or 7 may cause a breach to a 16-inch line on the RCW Cooler Discharge Header.
- HELB 1-C-037-R Breaks 2, 3 or 8 may cause a breach to a 24-inch line on the RCW Cooler Discharge Header
- HELB 1-FDW-031-R Breaks 6 or 7 may cause breaches to a 30-inch suction line to the 'A' and 'B' LPSW pumps, two 24-inch lines and a 16-inch line on the shared Units 1 & 2 LPSW 'B' Essential header
- HELB 1-FDW-031-R Break 11 may cause a breach to a 42-inch CCW crossover line

The following are Unit 2 HELBs that may cause repair activities to piping needed for cold shutdown:

- HELB 2-FDW-025-R Break 10 may cause breaches to a 10-inch, a 16-inch, an 18-inch and a 24-inch LPSW return lines from the Unit 2 decay heat removal coolers
- HELB 2-FDW-033-R Breaks 4 or 5 may cause a breach to a 20-inch line on the LPSW 'B' Essential Header

The following are Unit 3 HELBs that may cause repair activities to piping needed for cold shutdown:

- HELB 3-C-037-R breaks 4L or 5 may cause a breach to a 30-inch suction line to the 3A LPSW Pump
- HELB 3-FDW-008-R Break 14 may cause a breach to a 24-inch line that cross-connects the 3A and 3B LPSW Essential Headers
- HELB 3-FDW-031-R Break 4 may cause breaches to a 30-inch suction line to the 3B LPSW Pump, the 3B LPSW pump and its associated discharge piping, a 24-inch LPSW '3B' Essential header, and a 6-inch recirculation line for the 3A LPSW Pump
- HELB 3-MSRD-362-R02 Break 12 may cause a breach to a 24-inch LPSW '3A' Essential Header

No time estimates have been developed to repair any of these piping breaches at this time. While the units are being maintained in a long term subcooled natural circulation decay heat removal condition, the piping repairs and system alignments necessary to transition the units from Mode 4 (< 250°F) with decay heat removal via the SGs to Mode 5 (< 200°F) would be completed. The Oconee Emergency Response organization would coordinate these recovery actions augmented by fleet and industry personnel. Duke Energy would obtain materials and resources needed to restore the systems needed to achieve Mode 5, utilizing existing fleet resources and existing relationships with other utilities, suppliers, and manufacturers.

Postulated HELBs inside the Turbine Building can also cause breaches to the CCW piping. These breaches to the CCW system can result in flooding of the Turbine Building basement. The flooding continues until operator action is taken to isolate the CCW system from the lake. The CCW inlet is isolated by stopping all of the CCW pumps and closing the individual CCW pump discharge valves. The CCW discharge is isolated by lowering the CCW discharge gates. After the CCW system has been isolated from the lake, the flood waters in the Turbine Building basement will recede through the Turbine Building drain. Once flood waters have receded from the Turbine Building basement, operators would be dispatched to locate the source of the flooding. The affected unit's CCW system would be isolated from the other units' CCW systems to allow them to be restarted. The unit with the operating CCW system would be utilized to provide the LPSW pump suction for each unit. The flooding results in the potential loss of the LPSW pumps on all three units due to inundation of the pump motors. The damage repairs to LPSW would include replacing one LPSW pump motor to be shared by Units 1 and 2, and replacing one LPSW pump motor for Unit 3. There are two spare LPSW pump motors that can be installed using existing station procedures.

RAI 103

Section 3.2 of the June 29, 2009, LAR HELB analysis credits a submersible pump for replenishing the Unit 2 CCW embedded piping, which is the suction source for PSW and SSF. Assuming the maximum output of these systems, how long can PSW and SSF function before the submersible pump must be in place and functioning? What is the maximum flowrate from the submersible pump, and is it greater than the rate at which PSW or SSF will draw water from the CCW embedded piping? The submersible pump provides a required support function to the PSW and SSF; has a single active failure of the submersible pump been addressed?

Duke Energy Response

1. Assuming the maximum output of these systems, how long can PSW and SSF function before the submersible pump must be in place and functioning?

   Response:

   Per calculation OSC-2322, the worst case scenario for deploying the submersible pump to support the SSF is within 3 hours and 20 minutes after forced CCW flow and siphon flow are lost. Based on preliminary calculations, the deployment of the submersible pump to support PSW is bounded by the worst case scenario for deploying the submersible pump to support the SSF.

2. What is the maximum flow rate from the submersible pump, and is it greater than the rate at which PSW or SSF will draw water from the CCW embedded piping?

Response:

The maximum flow rate for the submersible pump is approximately 1100 gpm (Ref. OSC-2324). The secondary side flow rate to the steam generators required to support decay removal after the first two hours is $\leq$ 500 gpm and decreases with time (Ref. OSC-4171). The flow rates from the PSW and SSF service water pumps will be throttled to meet the decay heat requirements (Ref. AP/0/A/1700/25, SSF Emergency Operating Procedure and EC 91830). When the submersible pump is operating, its flow rate will be greater than the rate at which the PSW or SSF will be drawing water from the CCW embedded piping. Note that the PSW Booster Pump also provides a continuous cooling water flow rate of 10 gpm to each unit's High Pressure Injection (HPI) pump motor bearing coolers. (Ref. EC 91878)

3. The submersible pump provides a required support function to the PSW and SSF; has a single active failure of the submersible pump been addressed?

   Response: The submersible (portable) pump stored inside the SSF can be powered and operated from either the SSF or the PSW Building. Oconee has a spare portable pump, identical to the pump stored in the SSF. Note that the design of the SSF and PSW Systems does not include a requirement to postulate single active failures (Ref. SER on ONS SSF Design dated April, 28, 1983 and preliminary calculation OSC-10008, PSW System FMEA).

RAI 104

Section 2.3 of the June 29, 2009, LAR HELB analysis states, "Equipment that is used for the detection and isolation for an identified HELB is the only detection and isolation equipment required to be targets of that specific HELB."

Piping impacted by a broken high energy line will need to be isolated, both for flooding concerns and to facilitate efforts to mitigate the event. It is not clear from the statement above that the equipment needed to isolate piping damaged by HELB has been included as a target for HELB. Are there HELBs that result in an unisolable break?

Duke Energy Response

Pressure boundary piping and associated isolation valves were included as targets if the piping was needed to (a) establish safe shutdown, (b) provide for plant cooldown to a cold shutdown condition, or (c) its failure would result in flooding of the Turbine Building or Auxiliary Building.

The installation of the Main Steam Isolation Valves (MSIV) will provide isolation for the majority of the postulated breaks in the main steam piping. However, there would remain several locations upstream of the MSIVs where postulated breaks in the main steam system could not be isolated. These postulated break locations are discussed in detail in sections 4.2.1.1.3 and 4.2.1.5 (for Unit 1), sections 5.2.1.1.3 and 5.2.1.5 (for Unit 2), and sections 6.2.1.1.3 and 6.2.1.5 (for Unit 3) of the referenced HELB analysis.

There are postulated breaks downstream of the main feedwater isolation check valves located inside the East Penetration Room (EPR). A break at this location would result in an unisolable break on the affected steam generator. These postulated break locations are discussed in detail in sections 4.2.1.1.2 (for Unit 1), section 5.2.1.1.2 (for Unit 2) and section 6.2.1.1.2 (for Unit 3) of the referenced HELB analysis.

All postulated breaks in pressure boundary piping that can result in flooding of the Auxiliary Building can be isolated.

HELBs inside the Turbine Building can result in Emergency Feedwater (EFW) pressure boundary piping failures that would render the system unavailable. There is no credit being taken for isolation of the piping failures to restore EFW function. The loss of EFW is mitigated by the use of either the Protected Service Water (PSW) System or the Standby Shutdown Facility Auxiliary Service Water (SSF ASW) System. Failures in the EFW piping do not result in unacceptable flooding inside the Turbine Building due to the limited condensate inventory in the storage tanks.

HELBs inside the Turbine Building can result in Siphon Seal Water (SSW) pressure boundary failures that would render the system unavailable. There is no credit being taken for isolation of the piping failures to restore the SSW function. The loss of the SSW system may result in a loss of cooling to all three unit's Condenser Circulating Water (CCW) pumps, requiring the pumps to be secured. In addition, the loss of the SSW system would result in a loss of the Essential Siphon Vacuum (ESV) system. Emergency CCW flow cannot be assured without the ESV system. The combined loss of forced CCW flow and Emergency CCW flow is assumed to result in a loss of the Low Pressure Service Water (LPSW) function. The loss of LPSW function is discussed in the next paragraph. Failures in the SSW piping do not result in unacceptable flooding of the Turbine Building. Due to the small line size (4 inches in diameter), the flow rate resulting from the break can be released from the building through the Turbine Building drain.

HELBs inside the Turbine building may result in LPSW pressure boundary failures. (There are no postulated HELBs inside the Auxiliary Building that result in a failure of the LPSW pressure boundary.) Many of the failures can be isolated. There are cases where the failed piping results in the loss of the LPSW system function. Failure of the LPSW system can degrade other systems needed for safe shutdown, as well as result in the loss of cooldown capability to cold shutdown. The motor-driven EFW pumps are assumed to be lost due to the loss of motor cooling. If the turbine-driven EFW pump is not available, the EFW function would be lost. The loss of EFW function is mitigated by the PSW system. The High Pressure Injection (HPI) system is degraded by the loss of cooling to the HPI pumps. The PSW system also supplies cooling water to the HPI pumps to maintain the HPI function. The SSF systems would also be available to mitigate the loss of EFW and HPI, should the PSW system not be available. The LPSW pipe breaks that cannot be isolated will need to be repaired to enable a plant cooldown from 250°F to cold shutdown. Failures in the LPSW piping may result in Turbine Building flooding, depending on the location and size of the piping failure. Ruptures in the CCW piping provide the bounding flooding conditions.

HELBs inside the Turbine Building may result in CCW pressure boundary failures. The Turbine Building basement is susceptible to flooding from ruptures in the CCW System due to the much larger piping. Turbine Building flooding may result in a loss of all EFW and LPSW. The loss of EFW is mitigated by the PSW system or the SSF ASW system. The PSW system would provide cooling water to the HPI pumps to maintain HPI function. The SSF systems would also be available to mitigate the loss of EFW and HPI, should the PSW system not be available. The source of the Turbine Building flooding is isolated by stopping all CCW pumps, closing the CCW pump discharge valves, and by lowering the CCW Discharge Gates. The Turbine Building Drain provides the means for removing water from the basement to allow isolation of break locations and to effect repairs to piping that cannot be isolated.

RAI 105

Item 15 of the Atomic Energy Commission letter dated December 15, 1972 (ADAMS Accession No. 029949) (A. Giambusso letter) requested a discussion of the potential for flooding of safety-related equipment in the event of an HELB. When evaluating possible flooding, were non-safety lines broken by a high energy line considered as additional flooding sources?

Duke Energy Response

Yes. The Turbine Building basement is susceptible to flooding. Due to its large volume, only the Condenser Circulating Water (CCW) system is listed as a possible source of flooding. The Low Pressure Service Water (LPSW) system supply and return piping connecting to the CCW system are considered to be part of the CCW system pressure boundary. Therefore, the CCW system pressure boundary piping is included as possible HELB targets.

Non-safety systems were included as targets for HELBs inside the Auxiliary Building, if their failure could result in a release of inventory that could inundate safety-related equipment. There were no interactions with non-safety system that resulted in flooding in the Auxiliary Building.

RAI 106

Please provide under one cover all documentation associated with the tornado and HELB mitigation strategies. This should include an update to the original application as appropriate, updated regulator commitments, all updated RAIs, diagrams, figures and any other associated documentation. This request is being made because some documentation associated with the LARs has been superseded. The updated documentation will allow the NRC to accelerate the review of the LARs.

Duke Energy Response

Refer to Enclosure 3 for the updated HELB LAR package. As stated in the cover letter, Duke Energy plans to update the Tornado LAR by March 31, 2012.

RAI 107

To ensure licensing-basis clarity and component operability, Technical Specifications (TSs) need to properly address the PSW system in a manner that is consistent with the Standard TS requirements that have been established for the functions that are being performed by similar systems. For example, the minimum required mission time should be 7 days and the completion times should be limited to 72 hours in most cases. The proposed TS for the PSW system allow the system to be out of service for up to 45 days while maintenance is being performed on the system. The proposed TS does not put restrictions on other diverse systems (SSF) that are also used for tornado, HELB and fire mitigation while the PSW system is out of service. The suction source for the PSW system and the SSF are the same (Unit 2 circulation cooling water piping (CCW)). When the Unit 2 CCW piping is dewatered both the PSW system, and the SSF are out of service and cannot perform their intended functions. The proposed PSW TSs does not address this situation. Please address each of the above concerns.

Duke Energy Response

Duke Energy reviewed 44 other plant TSs and TS Bases to ascertain whether these plants had similar Criterion 4 systems that could be used to correlate Conditions, Required Actions, and Completion Times. Duke Energy also reviewed the BWOG, CEOG, WOG, and BWR STS. The review did not identify any Technical Specifications directly comparable to PSW. The closest comparison was the Safe Shutdown Makeup Pump System at Quad Cities. Also, the BWR plants have a single train RCIC system. These systems have a 14-day restoration time.

As concluded from the information given above, the STS emergency core cooling system guidelines are not directly applicable to the PSW system; however, Duke Energy determined that changes were warranted for the PSW system TSs. Specifically, Action A, completion time (CT) was revised to 14 days which is reasonable based on the SSF Auxiliary Service water and Reactor Coolant Makeup systems being operable and the low probability of a tornado or HELB event occurring during this time period. For Action C, the CT was revised to 30 days and the note was removed. Surveillance requirements were added for the battery charger (aligned with STS) and the PSW portable pump. The PSW Battery Parameters TS was revised to align with STS. As such, revised proposed PSW TSs are provided. In addition, Duke Energy proposes the following as a license condition to support implementation of the proposed TS changes:

"Upon implementation of the Amendment, TS SR 3.7.10.6, SR 3.7.10.8, SR 3.7.10.9 and SR 3.7.10.10 shall be considered met based on appropriate post modification testing. Following implementation, the first performance of SR 3.7.10.7, SR 3.7.10.9 and SR 3.7.10.10 is due at the next refueling outage of each Oconee unit after implementation of this amendment."

The revised draft PSW TS/TSB pages are given below (the PSW system TS Condition 'C' and Bases will provided by January 20, 2012).

3.7 PLANT SYSTEMS

3.7.10 Protected Service Water (PSW) System

LCO 3.7.10 The PSW System shall be OPERABLE

APPLICABILITY: MODES 1, 2, and 3
MODE 4 when steam generators are relied upon for heat removal.

ACTIONS

--NOTE--
LCO 3.0.4 is not applicable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. PSW System is inoperable.	A.1 Restore PSW System to OPERABLE status.	14 days
B. PSW System is inoperable. AND SSF Systems are inoperable.	B.1 Restore PSW System to OPERABLE status.	7 days
C. Required Action and associated Completion Time of Condition A or B not met when PSW inoperable due to maintenance [contingency actions under development].	C.1 [contingency actions under development]. AND C.2 Restore to OPERABLE status.	[contingency actions under development]. 30 days from discovery of initial inoperability.

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time of Condition C not met. OR Required Action and associated Completion Time of Condition A or B not met for reasons other than Condition C.	D.1 Be in MODE 3. AND D.2 Be in MODE 4.	12 hours 84 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.10.1	Verify required PSW battery terminal voltage is ≥ 125 VDC on float charge.	7 days
SR 3.7.10.2	Verify that the KHU underground can be aligned to and power the PSW electrical system.	92 days
SR 3.7.10. 3	--------------NOTE--------------------------------- Not applicable to the PSW portable pump. -- Verify that the developed head of the PSW pumps at the flow test point is greater than or equal to the required developed head.	In accordance with the Inservice Testing Program
SR 3.7.10.4	Verify battery capacity of required battery 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)

SURVEILLANCE		FREQUENCY
SR 3.7.10.5	Verify each PSW battery charger supplies ≥ 300 amps at greater than or equal to the minimum established float voltage for ≥ 8 hours <u>OR</u> Verify each battery charger can recharge the battery to the fully charged state within 24 hours while supplying the largest combined demands of the various continuous steady state loads, after a battery discharge to the bounding design basis event discharge state.	24 months
SR 3.7.10.6	Verify that the PSW switchgear can be aligned and power either the "A" or "B" HPI pumps	24 months
SR 3.7.10.7	Verify that the switches used for the "A" or "B" HPI pumps, pressurizer heaters, PSW control and electrical panels, and miscellaneous valves, are OPERABLE.	24 months
SR 3.7.10.8	Verify that the PSW pumps can be used to provide adequate cooling water flowrate to the HPI pump motor coolers.	24 months
SR 3.7.10.9	Verify the developed head of the PSW portable pump at the flow test point is greater than or equal to the required developed head.	24 months
SR 3.7.10.10	Verify that the PSW pumps can be aligned and provide flow to each unit's Steam Generator (SG)	48 months

B 3.7 PLANT SYSTEMS

B 3.7.10 Protected Service Water (PSW) System

BASES

BACKGROUND

The Protected Service Water (PSW) system is designed as a standby system for use under emergency conditions. The PSW System includes a dedicated power system. The PSW System provides added "defense in-depth" protection by serving as a backup to existing safety systems and as such, the system is not required to comply with single failure criteria. The PSW system is provided as an alternate means to achieve and maintain a stable RCS pressure and temperature for one, two, or three units following postulated event scenarios, e.g., tornado and high energy line break (HELB) events, and a loss of Lake Keowee event.

The PSW System is also capable of cooling the RCS to 250 °F and maintaining this condition until damage repairs can be implemented to proceed to cold shutdown. Failures in the PSW system will not cause failures or inadvertent operations in existing plant systems. The PSW system is fully controllable from the main control rooms and will be activated when existing redundant emergency systems are not available.

For a tornado event, the overall objective is to utilize the tornado-protected SSF system to maintain the units in Mode 3 for up to 72 hours while damage control measures are completed to restore any unavailable PSW/HPI system equipment needed to cooldown the units to approximately 250 °F. This temperature is the least that can be attained using the Steam Generators (SGs) for cooldown. The PSW/HPI systems can be used for an extended period of operation while additional repairs to systems, structures, and components (SSCs) required to transition the units to Mode 5 are completed.

For HELBs inside the Turbine building resulting in loss of 4160 essential power, either the SSF or the PSW system are used for safe shutdown. The SSF System is limited to 72 hours and is not credited for cooling the units beyond Mode 3 conditions (unless the initiating event causes the unit to be driven to a lower temperature). The PSW system is required to further cooldown to approximately 250 °F and for longer-term operation beyond the initial 72 hours. The PSW System can maintain

BACKGROUND (continued)

these conditions for all three units for an extended period of operation during which time other plant systems required to cool down to Mode 5 conditions will be restored and brought into service as required.

The mechanical portion of the PSW system is designed to provide decay heat removal by feeding Keowee Lake water to the secondary side of the steam generators. The system, consisting of one booster pump, one high head pump and a portable pump , shall be capable of providing 375 gpm per unit at 1082 psig within 15 minutes following the initiating event. In addition, the system is designed to supply Keowee Lake water at 10 gpm per unit to the HPI pump motor coolers.

The PSW system utilizes the inventory of lake water contained in the plant Unit 2 CCW embedded piping. The PSW pumps are located in the Auxiliary Building at Elev.771' (except the portable pump) and take suction from the Unit 2 CCW embedded piping and discharges into the steam generators of each unit via separate lines into the emergency feedwater headers. The raw water is vaporized in the steam generator removing residual heat and is dumped to atmosphere. The Unit 2 CCW embedded piping is interconnected with Units 1 & 3. For extended operation, the PSW portable pump with a flow path capable of taking suction from the intake canal and discharging into the Unit 2 CCW line, is designed to provide a backup supply of water to the PSW system in the event of loss of CCW and subsequent loss of CCW siphon flow. The PSW portable pump is installed manually according to procedures.

The piping system has pump minimum flow lines that discharge back into the Unit 2 CCW embedded piping. For flow testing to the steam generators, the system is connected to a condensate water source located in the Turbine Building that is normally isolated using valves in the Auxiliary Building.

The PSW pumps and motor operated and solenoid valves required to bring the system into service are controlled from the main control rooms. Check valves and manual handwheel operated valves are used to prevent back-flow, accommodate testing, or are used for system isolation. Periodic testing of the PSW valves and pumps (except the portable pump) will be performed in accordance with the In Service Testing (IST) program.

The PSW electrical system is designed to provide power to PSW mechanical and electrical components as well as other system components needed to establish and maintain a safe shutdown condition. A separate PSW electrical equipment structure is provided for major PSW electrical equipment. Power is provided from the KHU via a

BASES

BACKGROUND (continued)

tornado protected underground path. Alternate power is provided by a transformer connected to a 100 kV overhead transmission line that receives power from the Central Tie Switchyard located approximately 8 miles from the plant. These external power sources provide power to transformers, switchgear, breakers, load centers, batteries, and battery chargers located in the PSW electrical equipment structure.

The PSW HVAC is designed to maintain the Transformer Space (main equipment area) and the Battery rooms within their design temperature range. There are two redundant battery systems inside the PSW Building. The redundant battery banks are located in different rooms separated by fire rated walls. One HVAC system is QA-1; the other is non-QA. The hydrogen removal fans shall maintain the hydrogen in the Battery rooms below 2% in accordance with IEEE 484-2002. There are multiple thermostats in each Battery Room to ensure temperatures are maintained within acceptable limits.

APPLICABLE SAFETY ANALYSES

The safety function of the PSW system is to supply cooling water for secondary side decay heat removal at full system pressure to all six (6) steam generators (SGs) following postulated event scenarios. A secondary safety function of the PSW system is, in combination with the HPI System, to provide borated water to the RCS pump seals and to provide primary RCS makeup. Two redundant sources of electrical power serve the PSW electrical switchgear.

Because portions of the PSW System are not completely protected from the effects of a tornado, the system is not credited during the initial 72 hours after a tornado strike to the station. During the first 72 hours, the SSF will be utilized until damaged portions of the PSW system, which would be required for continued cooldown of the units to approximately

250 °F, are repaired. For HELBs occurring in the Turbine Building, the PSW System can be used as long as there is water contained in the underground CCW piping or until restorations are made to additional systems needed to cool down the units to Mode 5 conditions.

The PSW System is designed to mitigate the consequences of a loss of Lake Keowee event by providing emergency cooling water to one or more of the three Oconee Units' SGs and HPI pump motor coolers.

LCO

The PSW System is considered to be OPERABLE when its mechanical and electrical equipment, as well as associated support equipment, are OPERABLE. The system is designed to adequately perform these

LCO (continued)

functions for one, two, or all three units concurrently. The system is aligned, controlled, and monitored, from the main control rooms.

For OPERABILITY, the following are required:

- One (1) booster pump and one (1) high head pump.
- A viable suction source from the embedded Unit 2 CCW piping to the PSW pumping system.
- Five (5) of the six (6) 125 VDC Vital I&C Normal Battery Chargers

The following are required to be powered from PSW (each unit):

- Either the "A" or "B" High Pressure Injection Pump.
- HPI valves needed to align the HPI pumps to the Borated Water Storage Tanks (HP-24).
- HPI valves and instruments that support RCP seal injection and RCS makeup.
- PSW pumps flow to an HPI pump motor cooler.
- Pressurizer Heaters ($\geq$ 400 kW).
- RCS and Reactor Vessel Head high point vent valves
- PSW electrical system from either the KHU underground or 13.8 kV overhead power paths to support secondary side decay heat removal (SSDHR) and reactor coolant make-up (RCMU) functions.

PSW system dedicated instrumentation and controls located in each main control room:

- Two (2) high flow controllers (one per SG).
- Two (2) low flow controllers (one per SG).
- One (1) flow indicator (per SG).
- Two (2) SG header isolation valves (one per SG header).
- Two (2) HPI System power transfer switches per unit.
- Power transfer switches to HPI valves needed to align the BWST to the HPI pumps.

APPLICABILITY

In MODES 1, 2, and 3, the PSW System is required to be OPERABLE and to function in the event that all normal and emergency feedwater systems are lost. In MODE 4, with RCS temperature above 212 °F, the PSW

BASES

APPLICABILITY (continued)

System may be used for heat removal via the steam generators. In MODE 4, the steam generators are used for heat removal unless this function is being performed by the Low Pressure Injection System.

In MODE 4 steam generators are relied upon for heat removal whenever an RCS loop is required to be OPERABLE or operating to satisfy LCO 3.4.6, "RCS Loops – Mode 4."

In MODES 5 and 6, the steam generators are not used for SSDHR and the PSW System is not required.

ACTIONS

The exception for LCO 3.0.4, provided in the Note of the Actions, permits entry into MODES 1, 2, 3 or 4 with the PSW not OPERABLE. This is acceptable because the PSW is not required to support normal operation of the facility or to mitigate a design basis accident.

A.1

With the PSW system inoperable, action must be taken to restore the system to OPERABLE status within 14 days. The 14-day Completion Time is reasonable based on the SSF Auxiliary Service Water and RCMU systems being OPERABLE and a low probability of a tornado or HELB event occurring that would require the PSW System during the 14 day time period.

B.1

With both the PSW and SSF Systems inoperable, action must be taken to restore the PSW system to OPERABLE status within 7days. The required action is not intended for voluntary removal of both systems from service that provide alternate means for safe shutdown. This required action is applicable if the PSW system is inoperable for reasons other than maintenance and the SSF is found to be inoperable, or if both the PSW and the SSF systems are found to be inoperable at the same time. The 7 day Completion Time is based on the redundant heat removal capabilities afforded by other safety systems, reasonable times for repairs, and the low probability of a tornado or HELB event occurring that would require the PSW System during this time period.

ACTIONS (continued)

C.1 and C.2

If the Required Action and associated Completion Time of Condition A or B is not met when the PSW System is inoperable due to maintenance (e.g., dewatering of the Unit 2 CCW underground piping or repair of the PSW pump) [contingency actions under development], action must be taken to restore the PSW System to OPERABLE status within 30 days. Operation for 30 days is permitted [contingency actions under development]. The 30 days is from the time of discovery of initial inoperability.

[Contingency actions under development]

D.1 and D.2

If the Required Action and associated Completion Times of either Condition C or Conditions A or B are not met for reasons other than Condition C, the unit(s) must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours and MODE 4 within 84. The allowed Completion Times are appropriate to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems, considering a three unit shutdown may be required.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.10.1

Verifying battery terminal voltage while on float charge for the batteries helps to ensure the effectiveness of the charging system and the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery (or battery cell) and maintain the battery (or a battery cell) in a fully charged state. The voltage requirements are based on the nominal design voltage of the battery and are consistent with the initial voltage assumed in the battery sizing calculations. The 7 day frequency is consistent with manufacturer recommendations and IEEE-450.

SR 3.7.10. 2

This SR verifies the availability of the KHU associated with the underground power path to the PSW electrical system. Power path verification is included to demonstrate breaker OPERABILITY from the KHU to the PSW electrical system. This is accomplished by closing the Keowee to PSW Feeder Breakers. The 92 day Frequency is adequate based on operating experience to provide reliability verification without excessive equipment cycling for testing.

SR 3.7.10.3

This SR requires the PSW pumps be tested in accordance with the IST Program. The IST verifies the required flow rate at a discharge pressure to verify OPERABILITY. The SR is modified by a note indicating that it is not applicable to the PSW portable pump.

The specified Frequency is in accordance with the IST Program requirements. Operating experience has shown that these components usually pass the SR when performed at the IST Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.10.4

A battery service test is a special test of the battery capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length correspond to the design duty cycle requirements.

The Surveillance Frequency for this test is 24 months which is consistent with expected fuel cycle lengths.

SR 3.7.10.5

This SR verifies the design capacity of the battery charger. According to Regulatory Guide 1.32, the battery charger supply is recommended to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensure that these requirements can be satisfied.

This SR provides two options. One option requires that each battery charger be capable of supplying 300 amps at the minimum established float voltage for 8 hours. The ampere requirements are based on the output rating of the charger. The voltage requirements are based on the charger voltage level after a response to a loss of AC power. The time period if sufficient for the charger temperature to have stabilized and to have been maintained for at least 2 hours.

The other option requires that the battery charger be capable of recharging the battery after a service test coincident with supplying the largest coincident demands of the various continuous steady state loads (irrespective of the status of the plant during which these demands occur). This level of loading may not normally be available following the battery service test and will need to be supplemented with additional loads. The duration for this test may be longer than the charger sizing criteria since the battery recharge is affected by float voltage, temperature, and the exponential decay in charging current. The battery is recharged when the measured charging current is $\leq$ 2 amps. The Surveillance Frequency is acceptable, given the unit conditions required to perform the test and the other administrative controls existing to ensure adequate charger performance during these 24 month intervals.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.10.6

This SR verifies that the PSW switchgear can be aligned and power either the “A” or “B” HPI pumps once every 24 months.

SR 3.7.10.7

This SR verifies that the power transfer switches for the HPI pumps, pressurizer heaters, PSW control and electrical panels, and miscellaneous valves, are functional every 24 months.

SR 3.7.10.8

This SR verifies that the PSW pumps can supply Keowee Lake water at a flow rate greater than or equal to 10 gpm to the "A" or "B" HPI pump motor coolers (should there be a loss of normal LPSW cooling to these pumps) every 24 months.

SR 3.7.10.9

This SR requires the PSW portable pump to be tested on a 24 month frequency and verifies the required flow rate at a discharge pressure to verify OPERABIITY.

The specified frequency is based on the pump being not QA grade and on operating experience that has shown it usually passes the SR when performed at the 24 month frequency.

SR 3.7.10.10

The ability to align, start, and control flow of the PSW system to each unit must be verified every 48 months. This includes verification that the PSW header isolation valves to each unit's SGs open upon demand and that flow can be throttled to each SG through the full range of operation.

BASES (continued)

REFERENCES

1. Nuclear Station Report ONDS-351, "Analysis of Postulated High Energy Line Breaks (HELBs) Outside of Containment," dated May 20, 2008.
2. IEEE-450-1995.
3. Regulatory Guide 1.32, February 1977
4. Regulatory Guide 1.129, December 1974

3.7 PLANT SYSTEMS

3.7.10a Protected Service Water (PSW) Battery Parameters

LCO 3.7.10a Battery parameters for the PSW batteries shall be within limits.

APPLICABILITY: When the PSW system is required to be OPERABLE.

ACTIONS

--NOTES--
Separate Condition entry is allowed for each battery.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One battery on one train with one battery cell float voltage < 2.07 V.	A.1	Perform SR 3.7.10.1	2 hours
	<u>AND</u>		
	A.2	Perform SR 3.7.10a.1.	2 hours
	<u>AND</u>		
	A.3	Restore affected cell voltage $\geq$ 2.07 V.	24 hours
B. One battery on one train with float current > 2 amps.	B.1	Perform SR 3.7.10.1	2hours
	<u>AND</u>		
	B.2	Restore battery float current to $\leq$ 2 amps.	12 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
------------NOTE------------ Required Action C.2 shall be completed if electrolyte level was below the top of plates. ---------------------------------- C. One battery on one train with one or more cells electrolyte level less than minimum established design limits.	--------------NOTE--------------- Required Actions C.1 and C.2 are only applicable if electrolyte level was below the top of plates. -- C.1 Restore electrolyte level to above top of plates. <u>AND</u> C.2 Verify no evidence of leakage. <u>AND</u> C.3 Restore electrolyte level to greater than or equal to minimum established design limits.	 8 hours 12 hours 31 days
D. One battery on one train with pilot cell electrolyte temperature less than minimum established design limits.	D.1 Restore battery pilot cell temperature to greater than or equal to minimum established design limits.	12 hours
E. One battery with battery parameters not within limits.	E.1 Restore battery parameters for battery within limits.	2 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. Required Action and associated Completion Time of Condition A, B, C, D, or E not met. <u>OR</u> One battery on one train with one or more battery cells float voltage < 2.07 V and float current > 2 amps.	F.1 Declare associated battery inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.10a.1	--------------------NOTE-------------------- Not required to be met when battery terminal voltage is less than the minimum established float voltage of SR 3.7.10.1. -- Verify battery float current is ≤ 2 amps.	7 days
SR 3.7.10a.2	Verify battery pilot cell voltage is ≥ 2.07 V.	31 days
SR 3.7.10a.3	Verify battery connected cell electrolyte level is greater than or equal to minimum established design limits.	31 days

(continued)

ACTIONS (continued)

SR 3.7.10a.4	Verify battery pilot cell temperature is greater than or equal to minimum established design limits.	31 days
SR 3.7.10a.5	Verify battery connected cell voltage is ≥ 2.07 V.	92 days
SR 3.7.10.a.6	-----------------------NOTE-------------------------- This Surveillance shall not be performed in MODE 1, 2, 3, or 4. However, portions of the Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. --- Verify battery capacity is ≥ 80% of the manufacturer's rating when subjected to a performance discharge test or a modified performance discharge test.	60 months <u>AND</u> 12 months when battery shows degradation or has reached 85% of the expected life with capacity < 100% of manufacturer's rating <u>AND</u> 24 months when battery has reached 85% of the expected life with capacity ≥ 100% of manufacturer's rating

B 3.9 PLANT SYSTEMS

B 3.7.10a PSW Battery Parameters

BASES

BACKGROUND

This LCO delineates the limits on battery float current as well as electrolyte temperature, level, and float voltage for the PSW Power system batteries. In addition to the limitations of this Specification, the PSW Battery Monitoring and Maintenance Program specified in Specification 5.5.xx for monitoring various battery parameters that is based on the recommendations of IEEE Standard 450-1995, "IEEE Recommended Practice For Maintenance, Testing, And Replacement Of Vented Lead- Acid Batteries For Stationary Applications."

The battery cells are of flooded lead acid construction with a nominal specific gravity of 1.215. This specific gravity corresponds to an open circuit battery voltage of approximately 120 V for 58 cell battery (i.e., cell voltage of 2.065 volts per cell (Vpc)). The open circuit voltage is the voltage maintained when there is no charging or discharging. Once fully charged with its open circuit voltage < 2.065 Vpc, the battery cell will maintain its capacity for 30 days without further charging per manufacturer's instructions. Optimal long term performance however, is obtained by maintaining a float voltage 2.20 to 2.2 Vpc. This provides adequate over-potential which limits the formation of lead sulfate and self discharge. The nominal float voltage of 2.22 Vpc corresponds to a total float voltage output of 128.8 V for a 58 cell battery.

APPLICABLE SAFETY ANALYSES

The safety function of the PSW system is to supply cooling water for the secondary side decay heat removal at full system pressure to all six (6) steam generators (SGs) following postulated event scenarios. A secondary safety function of the PSW system is, in combination with the HPI System, to provide borated water to the RCS pump seals and to provide primary RCS makeup. Two redundant sources of electrical power serve the PSW electrical switchgear.

Because portions of the PSW System are not completely protected from the effects of a tornado, the system is not credited during the initial 72 hours after a tornado strike to the station. During the first 72 hours, the SSF will be utilized until damaged portions of the PSW system, which would be required for continued cooldown of the units to approximately

BASES

APPLICABLE SAFETY ANALYSES (continued)

250°F, are repaired. For HELBs occurring in the Turbine Building, the PSW System can be used as long as there is water contained in the underground CCW piping or until restorations are made to additional systems needed to cool down the units to Mode 5 conditions.

The PSW System is designed to mitigate the consequences of a loss of Lake Keowee event by emergency cooling water to one or more of the three Oconee Units' SGs and HPI pump motor coolers.

LCO

PSW Battery parameters must remain within acceptable limits to ensure availability of the required PSW DC power system to shut down the reactor and maintain it in a safe condition after an occurrence of a Tornado or High Energy Line Break inside the Turbine Building. Battery parameter limits are conservatively established, allowing continued PSW DC electrical system function even with limits not met. Additional preventative maintenance, testing, and monitoring performed in accordance with the PSW Battery Monitoring and Maintenance Program is conducted as specified in Specification 5.5.xx.

APPLICABILITY

The battery parameters are required solely for the support of the associated PSW electrical power systems. Therefore, battery parameter limits are only required when the PSW DC power source is required to be OPERABLE.

ACTIONS

A.1, A.2, and A.3

With one or more cells in a battery < 2.07 V, the battery cell is degraded. Within 2 hours verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage (SR 3.7.10.1) and of the overall battery state of charge by monitoring the battery float charge current (SR 3.7.10a.1). This assures that there is still sufficient battery capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of one or more cells in a battery < 2.07 V, and continued operation is permitted for a limited period up to 24 hours.

Since the Required Actions only specify "perform," a failure of SR 3.7.10.1 or SR 3.7.10a.1 acceptance criteria does not result in this Required Action not met. However, if one of the SRs is failed the appropriate Condition(s), depending on the cause of the failures, is entered. If SR 3.7.10a.1 is failed then there is no assurance that there is still sufficient battery capacity to perform the intended function and the battery must be declared inoperable immediately.

BASES

ACTIONS (continued)

B.1 and B.2

One battery with float current >2 amps indicates that a partial discharge of the battery capacity has occurred. This may be due to a temporary loss of a battery charger or possibly due to one or more battery cells in a low voltage condition reflecting some loss of capacity. Within 2 hours verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage. If the terminal voltage is found to be less than the minimum established float voltage there are two possibilities, the battery charger is inoperable or is operating in the current limit mode. Condition A addresses charger inoperability. If the charger is operating in the current limit mode after 2 hours that is an indication that the battery has been substantially discharged and likely cannot perform its required design functions. The time to return the battery to its fully charged condition in this case is a function of the battery charger capacity, the amount of loads on the associated DC system, the amount of the previous discharge, and the recharge characteristic of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within 12 hours (Required Action B.2). The battery must therefore be declared inoperable.

If the float voltage is found to be satisfactory but there are one or more battery cells with float voltage less than 2.07 V, the associated "OR" statement in Condition F is applicable and the. battery must be declared inoperable immediately. If float voltage is satisfactory and there are no cells less than 2.07 V there is good assurance that, within 12 hours, the battery will be restored to its fully charged condition (Required Action B.2) from any discharge that might have occurred due to a temporary loss of the battery charger.

A discharged battery with float voltage (the charger setpoint) across its terminals indicates that the battery is on the exponential charging current portion (the second part) of its recharge cycle. The time to return a battery to its fully charged state under this condition is simply a function of the amount of the previous discharge and the recharge characteristic of the battery. Thus there is good assurance of fully recharging the battery within 12 hours, avoiding a premature shutdown with its own attendant risk.

If the condition is due to one or more cells in a low voltage condition but still greater than 2.07 V and float voltage is found to be satisfactory, this is not indication of a substantially discharged battery and 12 hours is a reasonable time prior to declaring the battery inoperable.

BASES

ACTIONS

B.1 and B.2 (continued)

Since Required Action B.1 only specifies "perform," a failure of SR 3.7.10.1 acceptance criteria does not result in the Required Action not met. However, if SR 3.7.10.1 is failed, the appropriate Condition(s), depending on the cause of the failure, is entered.

C.1, C.2, and C.3

With one battery with one or more cells electrolyte level above the top of the plates, but below the minimum established design limits, the battery still retains sufficient capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of electrolyte level not met. Within 31 days the minimum established design limits for electrolyte level must be re-established.

With electrolyte level below the top of the plates there is a potential for dryout and plate degradation. Required Actions C.1 and C.2 address this potential (as well as provisions in Specification 5.5.xx, PSW Battery Monitoring and Maintenance Program). They are modified by a Note that indicates they are only applicable if electrolyte level is below the top of the plates. Within 8 hours level is required to be restored to above the top of the plates. The Required Action C.2 requirement to verify that there is no leakage by visual inspection and the Specification 5.5.xx. item to initiate action to equalize and test in accordance with manufacturer's recommendation are taken from Annex D of IEEE Standard 450. They are performed following the restoration of the electrolyte level to above the top of the plates. Based on the results of the manufacturer's recommended testing the battery may have to be declared inoperable and the affected cell[s] replaced.

D.1

With one battery with pilot cell temperature less than the minimum established design limits, 12 hours is allowed to restore the temperature to within limits. A low electrolyte temperature limits the current and power available. Since the battery is sized with margin, while battery capacity is degraded, sufficient capacity exists to perform the intended function and the affected battery is not required to be considered inoperable solely as a result of the pilot cell temperature not met.

BASES

ACTIONS (continued)

E.1

With one battery with parameters not within limits there is not sufficient assurance that battery capacity has not been affected to the degree that the battery can still perform their required function. The longer Completion Times specified for battery parameters not within limits are therefore not appropriate, and the parameters must be restored to within limits within 2 hours.

F.1

With one battery with any battery parameter outside the allowances of the Required Actions for Condition A, B, C, or D, sufficient capacity to supply the maximum expected load requirement is not assured and must be declared inoperable. Additionally, discovering one battery with one or more battery cells float voltage less than 2.07 V and float current greater than 2 amps indicates that the battery capacity may not be sufficient to perform the intended functions. The battery must therefore be declared inoperable immediately.

SURVEILLANCE REQUIREMENTS

SR 3.7.10a.1

Verifying battery float current while on float charge is used to determine the state of charge of the battery. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a charged state. The float current requirements are based on the float current indicative of a charged battery. Use of float current to determine the state of charge of the battery is consistent with IEEE-450. The 7 day Frequency is consistent with IEEE-450.

This SR is modified by a Note that states the float current requirement is not required to be met when battery terminal voltage is less than the minimum established float voltage of SR 3.7.10.1. When this float voltage is not maintained, actions should be taken to provide the necessary and appropriate verifications of the battery condition. Furthermore, the float current limit of 2 amps is established based on the nominal float voltage value and is not directly applicable when this voltage is not maintained.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.10a.2 and SR 3.7.10a.5

Optimal long term battery performance is obtained by maintaining a float voltage greater than or equal to the minimum established design limits provided by the battery manufacturer, which corresponds to 130.5 V at the battery terminals, or 2.25 Vpc. This provides adequate over-potential, which limits the formation of lead sulfate and self discharge, which could eventually render the battery inoperable. Float voltages in this range or less, but greater than 2.07 Vpc, are addressed in Specification 5.5.xx. SRs 3.7.10a.2 and 3.7.10a.5 require verification that the cell float voltages are equal to or greater than the short term absolute minimum voltage of 2.07 V. The Frequency for cell voltage verification every 31 days for pilot cell and 92 days for each connected cell is consistent with IEEE-450.

SR 3.7.10a.3

The limit specified for electrolyte level ensures that the plates suffer no physical damage and maintains adequate electron transfer capability. The Frequency is consistent with IEEE-450.

SR 3.7.10a.4

This Surveillance verifies that the pilot cell temperature is greater than or equal to the minimum established design limit (i.e., 40°F). Pilot cell electrolyte temperature is maintained above this temperature to assure the battery can provide the required current and voltage to meet the design requirements. Temperatures lower than assumed in battery sizing calculations act to inhibit or reduce battery capacity. The Frequency is consistent with IEEE-450.

SR 3.7.10a.6

A battery performance discharge test is a test of constant current capacity of a battery, normally done in the as found condition, after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage.

Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.7.10a.6; however, only the modified performance discharge test may be used to satisfy the battery service test requirements of SR 3.7.10.4.

SURVEILLANCE REQUIREMENTS

SR 3.7.10a.6 (continued)

A modified discharge test is a test of the battery capacity and its ability to provide a high rate, short duration load (usually the highest rate of the duty cycle). This will often confirm the battery's ability to meet the critical period of the load duty cycle, in addition to determining its percentage of rated capacity. Initial conditions for the modified performance discharge test should be identical to those specified for a service test.

It may consist of just two rates; for instance the one minute rate for the battery or the largest current load of the duty cycle, followed by the test rate employed for the performance test, both of which envelope the duty cycle of the service test. Since the ampere-hours removed by a one minute discharge represents a very small portion of the battery capacity, the test rate can be changed to that for the performance test without compromising the results of the performance discharge test. The battery terminal voltage for the modified performance discharge test must remain above the minimum battery terminal voltage specified in the battery service test for the duration of time equal to that of the service test.

The acceptance criteria for this Surveillance are consistent with IEEE-450 and IEEE-485. These references recommend that the battery be replaced if its capacity is below 80% of the manufacturer's rating. A capacity of 80% shows that the battery rate of deterioration is increasing, even if there is ample capacity to meet the load requirements. Furthermore, the battery is sized to meet the assumed duty cycle loads when the battery design capacity reaches this 80 percent limit.

The Surveillance Frequency for this test is normally 60 months. If the battery shows degradation, or if the battery has reached 85% of its expected life and capacity is < 100% of the manufacturer's rating, the Surveillance Frequency is reduced to 12 months. However, if the battery shows no degradation but has reached 85% of its expected life, the Surveillance Frequency is only reduced to 24 months for batteries that retain capacity ≥ 100% of the manufacturer's ratings. Degradation is indicated, according to IEEE-450, when the battery capacity drops by more than 10% relative to its capacity on the previous performance test or when it is ≥ 10% below the manufacturer's rating. These Frequencies are consistent with the recommendations in IEEE-450.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.10a.6 (continued)

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would perturb the electrical distribution system and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1, 2, 3, or 4 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1, 2, 3, or 4. Risk insights or deterministic methods may be used for the assessment. Credit may be taken for unplanned events that satisfy this SR.

REFERENCES

1. IEEE-450-1995
2. UFSAR, Chapter 15.
3. IEEE-485-1983, June 1983.

RAI 108

Based on the NRC staff's review of the proposed tornado LAR and all supplements the NRC staff finds that the licensee's proposed changes to the ONS UFSAR concerning the requirements of additional physical protection for SSCs against tornado guided missiles (TGMs), and the addition of the new Section 3.5.1.3.1 TORMIS Methodology to the UFSAR to describe the EPRI methodology used for the ONS probabilistic missile strike analysis, is unacceptable. Based on the NRC staff review of the information that was submitted the NRC staff has identified the following two specific deficiencies. First, the licensee incorrectly limited the target set to equipment required to support the initial 72 hours after a tornado. This fails to include the additional SSCs that are required to achieve the safe and stable plant condition. Second, the licensee has failed to demonstrate that it has applied a systematic and structured process supporting the development of a final target list which would provide confidence that all unprotected SSCs important to safety to withstand a tornado missile threat have been identified.

Described how all the SSCs needed to maintain safe and stable conditions following a tornado will be protected.

Duke Energy Response

The ONS strategy for addressing tornado missiles employs TORMIS in combination with positive missile protection and a repair strategy to demonstrate that the public health and safety will not be adversely impacted and that SSCs will not lose their capability to perform their safety functions as the plant proceeds from full power to Mode 3 within 72 hours following a tornado strike and then transitioning to Mode 4 and cold shutdown. There is reasonable assurance that repairs can be accomplished within those 72 hours to any damaged SSCs necessary to proceed to Mode 4 so that those SSCs will have the capability to perform their safety functions when required. These repairs are limited. ONS can safely remain in Mode 4, steaming on the steam generators, for an extended period, while undertaking repair of additional SSCs required for proceeding to cold shutdown.

SRP 3.5.1.4 (Missiles Generated by Tornadoes and Extreme Winds) states that SSCs shall be protected against tornado missiles without the loss of capability to perform their safety functions in accordance with GDC 2. There are identical words in RG 1.76, Rev. 1 (Design Basis Tornado and Tornado Missiles for Nuclear Power Plants.) The SRP Section also states that plants must remain in a safe condition in the event of the most severe tornadoes.

RIS 2008-14 (Use of TORMIS Computer Code for Assessment of Tornado Missile Protection) indicates that plants should be designed to withstand the effects of tornado missiles so as to not adversely impact the health and safety of the public in accordance with GDCs 2 and 4 and SRP Section 3.5.1.4. Similar words are also in the TORMIS November 29, 1983 SER in the Introduction Section.

Duke Energy has been unable to locate any statements in the TORMIS documentation that define the end state for a TORMIS application. The criteria in the various documents quoted above employ the words, "without the loss of capability to perform their safety functions" or "not adversely impact the health and safety of the public." The phrase, "safe and stable" is not used.

Duke Energy believes that following a tornado strike, ONS will remain in a safe condition and be able to proceed to Mode 4 without SSCs losing the capability to perform their safety functions when required. Therefore the health and safety of the public will be not adversely impacted. The ONS tornado mitigation strategy employs TORMIS in combination with positive missile protection and a repair strategy.

The stated acceptance criteria for TORMIS are based on the expected rate of occurrence of potential exposures in excess of 10CFR100 guidelines. Therefore, the process of identifying TORMIS targets began by recognizing that achieving and maintaining hot standby conditions (Mode 3) provides core cooling and ensures fuel integrity such that radiological releases in excess of 10CFR100 limits do not occur. While lower operational modes are the ultimate goal of the tornado mitigation strategy, they are not necessary to maintain core cooling and fuel integrity. Under this approach, a list of systems that could achieve and maintain Mode 3 conditions was initially considered and reviewed. These included EFW, HPI and the new PSW system. However, it was recognized that SSF provides an independent means of achieving Mode 3 without active support from other plant systems. As a result, the target list development process focused on identifying unprotected SSCs that could directly or indirectly cause failure of the SSF mitigation system. Other plant systems that potentially could provide mitigation capability were conservatively assumed to fail and were not included in the TORMIS analysis model. Credit for these systems as a diverse means to provide core cooling and prevent fuel damage would serve only to reduce the probability of a significant radiological release. Thus, by demonstrating that the probability of damage to SSF related equipment is less than 1E-06 per year, the overall plant damage frequency is less than 1E-06 per year and the TORMIS acceptance criteria is met. The other plant mitigation systems are only credited as a qualitative argument that actual plant damage frequency is expected to be less. The systematic process for developing TORMIS targets is discussed in Attachment 4, Sections 5.1 and 5.2 of the LAR.

In the ONS NFPA-805 SER (dated December 29, 2010), the NRC stated that the ONS' predetermined strategy with supporting procedures and repair equipment to prepare for transition from hot standby to long-term decay heat removal within 72 hours provided reasonable assurance that the fuel would remain in a safe and stable condition. Duke Energy believes that this precedence demonstrates acceptance of the concept that limited repair of selected SSCs within 72 hours is an acceptable strategy for maintaining the plant in a safe condition for certain events.

MISC. Issue

A typographical error was discovered on UFSAR Table 3-23 of the LAR. The table references Duke Energy calculation OSC-9180. The correct calculation is OSC-9160.

Duke Energy Response

A correction to the submitted UFSAR Table 3.23 marked-up (with Insert 2) and reprinted pages are shown on the following pages.

Table 3-23. Auxiliary Building Loads and Conditions

AREA	CONDITIONS	
Control Room	A,B,C,D,E	See Note 1
Cable Room	A,D,E	
Electrical Equipment Room	A,D,E	
Spent Fuel Pool	A,B,C,D,E	Blow out panels designed to relieve 3 psi differential pressure
Spent Fuel Storage Racks	A,D	Inherently resistant to wind loads
Spent Fuel Handling Crane	A,D,E	Inherently resistant to wind loads. Hold down device provided
Penetration Room Frames	A,B,D	Physical separation provided for missile protection
Cable Shaft	A,B,C,D,E	
Elevator Steel Shaft	A,D	
Main Steam Pipe Supports	A,B,D	
Hot Machine Shop	A,D	
Balance of Auxiliary Building	A,B,D	Frame designed for B, but not external walls above grade. Areas below grade are inherently protected against missiles in C and E.

Add: "See Note 2"

A = All normal dead, equipment, live, and wind loads due to 95 mph wind or design basis earthquake.

B = Normal dead and equipment loads plus tornado wind load due to 300 mph wind.

C = Tornado missiles of (1) 8 in. diameter x 12 ft. long piece of wood, 200 pounds, 250 mph, and (2) 2,000 pound automobile, 100 mph, 20 sq. ft. impact area, for 25 ft. above grade.

D = Normal dead and equipment loads plus maximum hypothetical earthquake loads.

E = Turbine-generator missile, 5,944 pounds, 502 fps, kinetic energy of 23.25 x 10^6 ft.-lbs., side on impact area of 8.368 sq. ft. and end on impact area of 3.657 sq. ft.

Note:

1. The information concerning tornado loads for Unit 3 Control Room North wall presently is incorrect and should not be used.

Add: Insert 2

INSERT 2

"2. The walls for these rooms are not directly exposed to tornado wind loads and consequently, pursuant to UFSAR 3.3.2, "Tornado Loadings" requirements, they were neither required nor constructed to withstand tornado loadings. However, Duke has evaluated[6] that only two relatively small areas, i.e., the cable and equipment room walls which face the Turbine Building) that comprise less than 1-percent of the available target area, could be vulnerable to a missile strike. Consequently, there is reasonable qualitative assurance that the integrity of these walls would not be compromised by a damaging tornado."

[6] Duke calculation: OSC-~~01809~~9160, "Tornado LAR (2007), Documentation of Miscellaneous Civil Inputs," Rev. 0.

Table 3-23. Auxiliary Building Loads and Conditions

AREA	CONDITIONS	
Control Room	A,B,C,D,E	See Note 1
Cable Room	A,D,E	See Note 2
Electrical Equipment Room	A,D,E	See Note 2
Spent Fuel Pool	A,B,C,D,E	Blow out panels designed to relieve 3 psi differential pressure
Spent Fuel Storage Racks	A,D	Inherently resistant to wind loads
Spent Fuel Handling Crane	A,D,E	Inherently resistant to wind loads. Hold down device provided
Penetration Room Frames	A,B,D	Physical separation provided for missile protection
Cable Shaft	A,B,C,D,E	
Elevator Steel Shaft	A,D	
Main Steam Pipe Supports	A,B,D	
Hot Machine Shop	A,D	
Balance of Auxiliary Building	A,B,D	Frame designed for B, but not external walls above grade. Areas below grade are inherently protected against missiles in C and E.

A = All normal dead, equipment, live, and wind loads due to 95 mph wind or design basis earthquake.

B = Normal dead and equipment loads plus tornado wind load due to 300 mph wind.

C = Tornado missiles of (1) 8 in. diameter x 12 ft. long piece of wood, 200 pounds, 250 mph, and (2) 2,000 pound automobile, 100 mph, 20 sq. ft. impact area, for 25 ft. above grade.

D = Normal dead and equipment loads plus maximum hypothetical earthquake loads.

E = Turbine-generator missile. 5,944 pounds, 502 fps, kinetic energy of 23.25×10^6 ft.-lbs., side on impact area of 8.368 sq. ft. and end on impact area of 3.657 sq. ft.

Notes:

1. The information concerning tornado loads for Unit 3 Control Room North wall presently is incorrect and should not be used.
2. The walls for these rooms are not directly exposed to tornado wind loads and consequently, pursuant to UFSAR 3.3.2, "Tornado Loadings" requirements, they were neither required nor constructed to withstand tornado loadings. However, Duke has evaluated that only two relatively small areas, i.e., the cable and equipment room walls which face the Turbine Building, that comprise less than 1-percent of the available target area, could be vulnerable to a missile strike. Consequently, there is reasonable qualitative assurance that the integrity of these walls would not be compromised by a damaging tornado missile. (Ref.: Duke Calculation: OSC-9160, "Tornado LAR (2007), Documentation of Miscellaneous Civil Inputs," Rev. 0)

Enclosure 2

Updated List of Current Tornado and HELB Commitments

No.	Tornado Commitments	Due Date	Complete (Y/N)[6]
1T	U3 Control Room North Wall Modification.	-	Y
2T	SSF Diesel Fuel Vent Modification.	-	Y
3T	SSF and CT-5 Trenches Intersection Modification SSF Trench at north end of SSF (TORMIS).	-	Y
4T	Borated Water Storage Tank Modifications.	-	Y
5T	West Penetration Room (WPR) and Cask Decontamination Tank Room (CDTR) Wall Modifications.	-	Y
6T	Fiber Reinforced Polymer (FRP) LAR for strengthening selected masonry walls for tornado wind and ΔP.	-	Y
7T	Tornado Mitigation Strategy LAR.	-	Y
8T	PSW/HPI modifications.	7-2012	N
9T	Missile inventory program developed.		Y
10T	Verbally notify in advance the Deputy Director, Division of Reactor Licensing of the NRC, followed by a written communication, of significant changes in the scope and/or completion dates of the commitments. The notification will include the reason for the changes and the modified commitments and/or schedule.	6-2016	N
11T 12T 13T	Installation of MSIVs.	U1: 12-2014 U2: 12-2015 U3: 06-2016	N
14T	Fiber Reinforced Polymer (FRP) LAR for strengthening selected "brick" masonry walls for tornado wind and ΔP.	-	Y
15T	Analyze the double column set which support each unit's Main Steam lines outside of the containment building, and provide modifications, as necessary, to meet tornado criteria	-	Y
16T	Physically protect the Atmospheric Dump Valve's (ADV's) function per RG 1.76, Rev. 1.	U1: 12-2014 U2: 12-2015 U3: 06-2016	N
17T	Improve protection of the Standby Shutdown Facility (SSF) double doors (large 8'x12' doors located on the south side of the SSF structure) per UFSAR SSF tornado criteria.	12-31-2013	N
18T	Revise and clarify the tornado LB description as documented in UFSAR Section 3.2.2; add the TORMIS methodology results to UFSAR Section 3.5.1.3, and correct inaccurate tornado design information for the Auxiliary Building Cable and Electrical Equipment Rooms as described in UFSAR Table 3-23.	After issuance of the SER.	N
19T	The SSF BASES for TS 3.10.1 will be clarified to address degradation of passive civil features as not applying to operability under Technical Specifications Limiting Condition for Operation (TS LCO) 3.10.1, “Standby Shutdown Facility,” but rather as UFSAR commitments outside of the ONS TS.	After issuance of the SER.	N
20T[7]	Duke Energy will perform qualification testing and reporting	-	Y

[6] As of December 16, 2011.

No.	Tornado Commitments	Due Date	Complete (Y/N)[6]
	in accordance with ICC AC125 [Reference 5 of Enclosure 2] for the selected FRP System.		
21T	Duke Energy will perform and document a technical evaluation of the FRP system (fibers and polymeric resin) in accordance with Duke Energy's Supply Chain Directive SCD230 [Reference 7 of Enclosure 2] to demonstrate that: 1. The item qualifies as a commercial grade item. 2. The supplier is capable of supplying a quality product. 3. The quality of the item can be reasonably assured.	-	Y
22T	Duke Energy will utilize technical procedures to control testing of concrete substrate and installation and inspection of the FRP system in accordance with ICC AC125 [Reference 5 of Enclosure 2], ACI 440.2R-02 [Reference 6 of Enclosure 2], and ICC AC178 [Reference 8 of Enclosure 2].	-	Y
23T	Duke Energy will perform long-term inspection of the FRP system as described in UFSAR Section 18.3.13 and EDM-410, and in accordance with ICC AC125 [Reference 5 of Enclosure 2], ACI 440.2R-02 [Reference 6 of Enclosure 2], and ICC AC178 [Reference 8 of Enclosure 2], on a nominal 5 year interval. This inspection frequency may be reduced to a nominal 10 year interval with appropriate justification based on the structure, environment, and previous long-term inspection results. Inspections of the installed FRP system will include: • visual inspections of test walls and selected portions of WPR walls for changes in color, debonding, peeling, blistering, cracking, crazing, deflections and other anomalies; and, • tension adhesion testing of cored samples taken from test walls using methods specified in ASTM D4541 [Reference 9 of Enclosure 2] or ACI 530R-02 [Reference 16 of Enclosure 2].	-	Y [see 27T]
24T[8]	Duke Energy will perform qualification testing and reporting in accordance with ICC AC125 [Approved 10/2006, Effective 1/1/2007] for the selected FRP System.	-	Y
25T	Duke Energy will perform and document a technical evaluation of the FRP system (fibers and polymeric resin) in accordance with Duke Energy's Supply Chain Directive SCD230 [Reference 7 of Enclosure 2] to demonstrate that: • The item qualifies as a commercial grade item.	-	Y

[7] Tornado commitments 20-23 originate from the FRP LAR dated 6-1-2006 (NRC SER dated 2-21-2008).

[8] Tornado commitments 20-26 are addressed in the NRC's FRP SER for brick masonry dated 6-27-2011. The completion status has been updated for several of the commitments.

No.	Tornado Commitments	Due Date	Complete (Y/N)[6]
	• The supplier is capable of supplying a quality product. • The quality of the item can be reasonably assured.		
26T	Duke Energy will utilize technical procedures to control testing of concrete substrate and installation and inspection of the FRP system in accordance with ICC AC125 [Approved 10/2006, Effective 1/1/2007], ACI 440.2R-02 [Effective 7/1/2002], and ICC AC178 [Approved 6/2003, Effective 7/1/2003, editorially revised 6/2008].	-	Y
27T	Duke Energy will implement a long-term inspection program of the FRP system that will be described in UFSAR Section 18.3.13 and EDM-410, meet the requirements of ICC AC125 [Approved 10/2006, Effective 1/1/2007], ACI 440.2R-02 [Effective 7/1/2002], and ICC AC178 [Approved 6/2003, Effective 7/1/2003, editorially revised 6/2008], on the following schedule: at each unit's outage cycle for the first six years from 2012 through 2017, then, if justified based on no observed FRP degradation, transition to every-other outage cycle for the next four years from 2018 through 2021, then, if justified based on continued no observed FRP degradation, transition to every third outage cycle thereafter from 2022 until end of license in July 2034. Inspections of the installed FRP system will include: • visual inspections of test walls and portions (both random and controlled locations) of WPR in-service walls for changes in color, debonding, peeling, blistering, cracking, crazing, deflections and other anomalies; • tension adhesion testing of cored samples taken from designated test walls using methods specified in ASTM D7234; and, • visual inspections of mortar joints located along the bottom edge of FRP-strengthened masonry walls. For each inspection interval, the portions of FRP-strengthened masonry walls to be inspected will be chosen in accordance with a sampling plan developed from guidance provided by a) Draft Regulatory Guide DG-1070, "Sampling Plans Used for Dedicating Simple Metallic Commercial Grade Items for use in Nuclear Power Plants", and b) EPRI NP-7218 document "Guidelines for the Utilization of Sampling Plans for Commercial Grade Item Acceptance" (NCIG-19), as implemented at ONS by Supply Chain Directive SCD-290 [(new) Reference 21 of Enclosure 2]. Note: This response replaces the five (5) year inspection commitment made in FRP LAR (No. 2009-05) dated June 29, 2009, and will apply to the FRP application for both	Prior to startup from the Unit 3 Spring 2012 refueling outage.	N

No.	Tornado Commitments	Due Date	Complete (Y/N)[6]
	block and brick.		
28T	Duke Energy will install mechanical shear restraints along the brick masonry wall perimeter (top and sides only) and block masonry wall perimeter (top only) to remediate potentially limiting conditions of construction.	-	Y
29T	Duke Energy will incorporate the FRP testing and inspection program into Oconee Nuclear Station's Aging Management Program.	-	Y
30T	As discussed with the Staff, Fyfe Company, LLC, the manufacturer of the FRP products, will provide Duke Energy with a Certificate of Compliance certifying that both the FRP product and its installation meet all applicable requirements.	-	Y

No.	HELB Commitments	Due Date	Complete (Y/N)[9]
1H	Implement an inspection program for the Aux Bldg MS and FW girth and accessible attachment welds.	-	Y
2H	Implement an inspection program for other Aux. Bldg high energy piping critical crack locations at welds.	-	Y
3H	Initial ASME Section XI ISI interval UT of the Aux. Bldg MS and FW girth welds and accessible attachment welds.	-	Y
4H	Initial ASME Section XI ISI interval UT of other Aux. Bldg high energy piping critical crack locations at welds.	-	Y
5H	Implement an inspection program for accessible piping base metal downstream of the FW isolation valves located in the EPR.	-	Y
6H	Implement an inspection program for accessible piping base metal of other Aux. Bldg high energy piping critical crack locations not at welds.	-	Y
7H	Initial ASME Section XI ISI interval UT inspection of piping base metal downstream of FW isolation valves located in the EPR.	-	Y
8H	Initial ASME Section XI ISI interval UT inspection for accessible piping base metal of other Aux. Bldg high energy piping critical crack locations not at welds.	-	Y
9H	Implement an inspection program of accessible attachment welds at the terminal ends inside the FW guard pipe.	-	Y
10H	Initial visual inspections of accessible attachment welds at the terminal ends inside the FW guard pipe.	-	Y
11H	Inspect and repair the Unit 2 East Penetration Room electrical penetration termination enclosures to their correct configuration. Missing and/or damaged covers, gaskets, and fasteners will be repaired or replaced.	-	Y
12H	Inspect and repair the Unit 1 East Penetration Room electrical penetration termination enclosures to their correct configuration. Missing and/or damaged covers, gaskets, and fasteners will be repaired or replaced.	-	Y
13H	Inspect and repair the Unit 3 East Penetration Room electrical penetration termination enclosures to their correct configuration. Missing and/or damaged covers, gaskets, and fasteners will be repaired or replaced.	-	Y

[9] As of December 16, 2011.

No.	HELB Commitments	Due Date	Complete (Y/N)[9]
14H	Create an inspection plan to select a portion of Units 1, 2 and 3 enclosures to open and inspect for signs of internal debris and corrosion.	-	Y
15H	Revise station procedures and processes as needed to ensure penetration termination enclosures are maintained in their correct configurations.	-	Y
16H	Complete the design and installation of flood outlet devices for the Unit 1 East Penetration Room.	-	Y
17H	Complete the design and installation of flood outlet devices for the Unit 2 East Penetration Room.	-	Y
18H	Complete the design and installation of flood outlet devices for the Unit 3 East Penetration Room.	-	Y
19H	Complete the design and installation of flood impoundment and exterior door flood improvement features for the Unit 1 East Penetration Room	-	Y
20H	Complete the design and installation of flood impoundment and exterior door flood improvement features for the Unit 2 East Penetration Room.	-	Y
21H	Complete the design and installation of flood impoundment and exterior door flood improvement features for the Unit 3 East Penetration Room.	-	Y
22H 23H 24H	HELB LB and Mitigation Strategy LARs.	-	Y
25H	Verbally notify in advance the Deputy Director, Division of Reactor Licensing of the NRC, followed by a written communication, of significant changes in the scope and/or completion dates of the commitments. The notification will include the reason for the changes and the modified commitments and/or schedule.	As necessary until 7-2012	N
26H	The inlet isolation valves to the Letdown Coolers on the Letdown Line (1HP-1 & 1HP-2) will be upgraded to permit their use following a postulated HELB on the Letdown Line at Containment Penetration No. 6. With these valves upgraded, either could then be closed if either of the inboard containment isolation valves (1HP-3 & 1HP-4) fails to close in order to mitigate the postulated HELB on the Letdown line.	To be provided to the Staff upon issuance of the SER.	N

No.	HELB Commitments	Due Date	Complete (Y/N)[9]
27H	The ducting near the Control Complex is being upgraded with duct registers or cover plates to prevent the potential propagation of the HELB generated environment in the East Penetration Room to the Control Complex.	To be provided to the Staff upon issuance of the SER.	N
28H	The valves (1HP-103 & 1HP-107) on the individual suction lines to the "A" & "B" High Pressure Injection (HPI) pumps are being upgraded to allow the remote operation (operated outside the HPI pump room) of these valves. The remote operation of these valves allow the isolation of postulated HELBs on the discharge side of the HPI Pumps without compromising the availability of the other HPI Pumps and the need for maintaining the Letdown Storage Tank aligned to the HPI Pump suction piping. For a single active failure of either valve 1HP-103 or 1HP-107 to close, a redundant, remotely operated valve is provided on each of the HPI Pumps "A" and "B" to assure HELB mitigation.	-	Y
29H	The position of several Plant Heating System isolation valves is being changed from "OPEN" to "CLOSED." This position change will eliminate the need to postulate Plant Heating System HELBs in the East Penetration Room and West Penetration Room, because these piping lines will isolated during normal plant conditions of the station.	-	Y
30H	Turbine Building structural support column D-26 will be modified by adding a brace to the column. This brace is necessary to prevent potential failure of the column, when subjected to a pipe whip load. This upgrade prevents the loss of the routing to get temporary cabling to the Low Pressure Injection and Low Pressure Service Water pump motors.	To be provided to the Staff upon issuance of the SER.	N
31H	The existing Condenser Circulating Water (CCW) discharge stop gates will be replaced and four (4) new stop gates will be obtained. These stop gates will be used to terminate all reverse flow through HELB damaged Low Pressure Service Water and CCW piping. This modification is required, in order to recover from a Turbine Building flood event caused by a postulated HELB therein.	To be provided to the Staff upon issuance of the SER.	N
32H	Evaluate the ability of the Standby Shutdown Facility to perform its safety functions with a compromised main steam pressure boundary due to potential breaks in the main steam system and other HELBs.	-	Y

No.	HELB Commitments	Due Date	Complete (Y/N)[9]
33H	Weep holes will be installed in the bottom of the outside-containment junction box enclosures for the Viking Electrical Penetrations. Also, the electrical penetration inspection procedure is being amended to inspect the weep holes for blockage	-	Y
34H	The inlet isolation valves to the Letdown Coolers on the Letdown Line (2HP-1& 2HP-2) will be upgraded to permit their use following a postulated HELB on the Letdown Line at Containment Penetration No. 6. With these valves upgraded, either could then be closed if either of the inboard containment isolation valves (2HP-3 & 2HP-4) fails to close in order to mitigate the postulated HELB on the Letdown line.	To be provided to the Staff upon issuance of the SER.	N
35H	The Unit 2 HVAC ducting near the Control Complex is being upgraded with duct registers or cover plates to prevent the potential propagation of the HELB generated environment in the East Penetration Room to the Control Complex.	To be provided to the Staff upon issuance of the SER.	N
36H	The valves (2HP-103 & 2HP-107) on the individual suction lines to the "A" & "B" High Pressure Injection (HPI) pumps are being upgraded to allow the remote operation (operated outside the HPI pump room) of these valves. The remote operation of these valves allow the isolation of postulated HELBs on the discharge side of the HPI pumps without compromising the availability of the other HPI Pumps and the need for maintain the Letdown Storage Tank aligned to the HPI Pump suction piping. For a single active failure of either valves 2HP-103 or 2HP-107 to close, a redundant, remotely operated valves is provided on each of the HPI Pumps "A" and "B" to assure HELB mitigation.	To be provided to the Staff upon issuance of the SER.	N
37H	The position of several Unit 2 Plant Heating System isolation valves is being changed from "OPEN" to "CLOSED." This position change will eliminate the need to postulate Plant Heating System HELBs in the East Penetration Room and West Penetration Room, because these piping lines will be isolated during normal plant conditions of the station.	-	Y
38H	Turbine Building structural support Column D-29 & D-31 will be modified by adding a brace to the column. This brace is necessary to prevent potential failure of the column, when subjected to a pipe whip load.	To be provided to the Staff upon issuance of the SER.	N

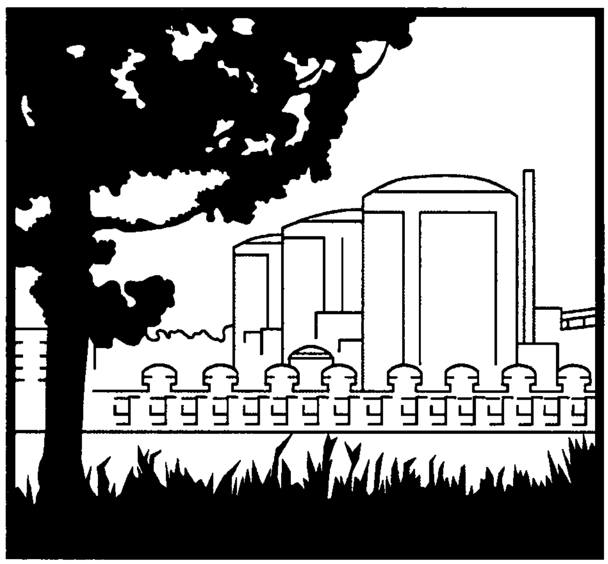
No.	HELB Commitments	Due Date	Complete (Y/N)[9]
39H	Weep holes will be installed in the bottom of the Unit 2 outside-containment junction box enclosures for the Viking Electrical Penetrations. Also, the electrical penetration inspection procedure is being amended to inspect the weep holes for blockage.	-	Y
40H	The inlet isolation valves to the Letdown Coolers on the Letdown Line (3HP-1 and 3HP-2) will be upgraded to permit their use following a postulated HELB on the Letdown Line at Containment Penetration No. 6. With these valves upgraded, either could then be closed if either of the inboard containment isolation valves (3HP-3 and 3HP-4) fails to close in order to mitigate the postulated HELB on the Letdown Line.	To be provided to the Staff upon issuance of the SER.	N
41H	The Unit 3 Auxiliary Building HVAC ducting near the Unit 3 Control Complex is being upgraded with duct registers or cover plates to prevent the potential propagation of the HELB generated environment in the East Penetration Room to the Unit 3 Control Complex.	To be provided to the Staff upon issuance of the SER.	N
42H	The valves (3HP-103 and 3HP-107) on the individual suction lines to the "A" and "B" High Pressure Injection (HPI) pumps are being upgraded to allow the remote operation (operated outside the HPI pump room) of these valves. The remote operation of these valves allow the isolation of postulated HELBs on the discharge side of the HPI Pumps without compromising the availability of the other HPI Pumps and the need for maintaining the Letdown Storage Tank aligned to the HPI Pump suction piping. For a single active failure of either valve 3HP-103 or 3HP-107 to close, a redundant, remotely operated valve is provided on each of the HPI Pumps "A" and "B" to assure HELB mitigation.	-	Y
43H	The position of the Unit 3 Plant Heating System isolation valve 3AS-182 being changed from "OPEN" to "CLOSED." This position change will eliminate the need to postulate Plant Heating System HELBs in the East Penetration Room and West Penetration Room, because these piping lines will be isolated during Normal Plant Conditions of the station.	-	Y
44H	Turbine Building structural support columns M-20 (Unit 1), M-35 (Unit 2), D-43 and D-45 (Unit 3), M-49 (Unit 3), and L-47 (Unit 3) will be modified by adding a brace or reinforcement to each column. These modifications are necessary to prevent potential failure of the column(s), when subjected to a pipe whip load.	To be provided to the Staff upon issuance of the SER.	N

No.	HELB Commitments	Due Date	Complete (Y/N)[9]
45H	Weep holes will be installed in the bottom of the Unit 3 outside-containment junction box enclosures for the Viking Electrical Penetrations. Also, the electrical penetration inspection procedure is being amended to inspect the weep holes for blockage.	-	Y

Enclosure 3

Repackaged HELB License Amendment Request

OCONEE NUCLEAR STATION
UNITS 1, 2, & 3



REPACKAGE OF HIGH ENERGY LINE BREAKS (HELBs) OUTSIDE OF CONTAINMENT LICENSE AMENDMENT REQUEST

DECEMBER 16, 2011

Tab 1: Duke Energy RAI response dated October 23, 2009

Tab 2: Duke Energy RAI response dated December 7, 2010

Tab 3: Unit 3 LAR (includes HELB Report data for Units 1, 2, and 3)

Tab 4: Updated Tornado and HELB Commitments

Tab 5: UFSAR Changes, and Revised Technical Specifications/Bases

Tab 6: HELB Diagrams and Figures (Units 1, 2, and 3)

Tab 1

Duke Energy RAI response dated 10-23-09

Duke Energy®

DAVE BAXTER
Vice President
Oconee Nuclear Station

Duke Energy
ONO1VP / 7800 Rochester Highway
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864-873-4208 fax
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October 23, 2009

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

Subject: Duke Energy Carolinas, LLC
Oconee Nuclear Station
Renewed Facility Operating Licenses Numbers DPR-38, DPR-47, and DPR-55;
Docket Numbers 50-269, 50-270, and 50-287
"Responses to Request for Additional Information for the License Amendment Request to Revise the Oconee Nuclear Station Current Licensing Basis for High Energy Line Break Events Outside of the Containment Building;"
License Amendment Request No. 2008-007

References:

1. Letter to the U. S. Nuclear Regulatory Commission from David Baxter, Vice President, Oconee Nuclear Station, Duke Energy Carolinas, LLC, "Proposed License Amendment Request to Revise the Oconee Nuclear Station Current Licensing Basis for HELB events outside of the Containment Buildings; License Amendment Request No. 2008-005," dated June 26, 2008.

2. Letter to the U. S. Nuclear Regulatory Commission from Dave Baxter, Vice President, Oconee Nuclear Station, Duke Energy Carolinas, LLC, "Proposed License Amendment Request to Revise the Oconee Nuclear Station Current Licensing Basis for HELB Events outside of the Containment Building – Unit 2; License Amendment Request No. 2008-006," dated December 22, 2008.

3. Letter to the U. S. Nuclear Regulatory Commission from Dave Baxter, Vice President, Oconee Nuclear Station, Duke Energy Carolinas, LLC, "Proposed License Amendment Request to Revise the Oconee Nuclear Station Current Licensing Basis for High Energy Line Break Events Outside of the Containment Building," License Amendment Request No. 2008-007, dated June 29, 2009.

4. Letter to Mr. Dave Baxter, Vice President, Oconee Nuclear Site, Duke Energy Carolinas, LLC, from the U. S. Nuclear Regulatory Commission, "Oconee Nuclear Station Unit 1 – Request for Additional Information (RAI) Regarding the Licensee Amendment Request for Upgrading the Licensing Basis for High Energy Line Break Mitigation (TAC NO. MD9029)," dated July 24, 2009.

5. Letter from the U. S. Nuclear Regulatory Commission to Duke Power Company LLC, "Summary of March 5, 2007, Meeting to Discuss the November 30, 2006, Letter Regarding Oconee High-Energy Line Break (HELB) and Tornado Mitigation Strategies (TAC NOS. MD3721, MD3722, MD3723, MD3724, MD3725, MD3726)," dated March 28, 2007.

6. Letter from Mr. Timothy J. McGinty, Deputy Director, Division of Operating Reactor Licensing, NRR, to Mr. Bruce H. Hamilton, Vice-President, Oconee Site, Duke Power Company, LLC., "Oconee Nuclear Station, Units 1, 2, and 3 (Oconee) – Tornado and High-Energy Line Break (HELB) Mitigation Strategies (TAC NOS MD3721, MD3722, MD3723, MD3724, MD3725 and MD3726)," dated May 15, 2007.

On June 29, 2009, Duke Energy Carolinas, LLC (Duke) submitted a License Amendment Request (LAR) to completely revise the Oconee Nuclear Station (ONS) current Licensing Basis (LB) regarding mitigating High Energy Line Break (HELB) events occurring outside of containment for Unit 3 [Ref. 3]. Prior to this, HELB LARs had been submitted for Unit 1 (June 26, 2008, [Ref. 1]), and Unit 2 (December 22, 2008, [Ref. 2]). Taken in aggregate, the LARs contained changes which were the result of an extensive and comprehensive HELB analysis and included several plant modifications necessary to support the revised HELB LB.

On July 24, 2009, Duke received a Request for Additional Information (RAI) [Ref. 4]. The attachment to this document contains Duke's responses to this RAI. When applicable, the responses are consistent with the common understandings reached with the NRC as documented in References 5 and 6.

Inquiries on this proposed amendment request should be directed to Stephen C. Newman of the Oconee Regulatory Compliance Group at (864) 873-4388.

I declare under penalty of perjury that the foregoing is true and correct. Executed on October 23, 2009.

Sincerely,

Dave Baxter, Vice President,
Oconee Nuclear Station

Attachment:

Responses to Request for Additional Information bc w/attachment:

Mr. J. F. Stang, Project Manager
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Mr. Curtis W. Rapp
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Mr. Andrew Sabisch
NRC Senior Resident Inspector
Oconee Nuclear Station

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bcc w/attachment:

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R. M. Glover
G. K. Mc Aninch
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S. L. Batson
R. J. Freudenberger
R. L. Gill – NRI&IA
R. D. Hart – CNS
K. L. Ashe - MNS
NSRB, EC05N
ELL, EC050
File - T.S. Working
ONS Document Management

ATTACHMENT

RESPONSES TO REQUEST FOR ADDITIONAL INFORMATION

RAI 1

Page 4 of Enclosure 2 of the LAR, states, "The enclosed HELB report includes safe shutdown analyses for HELBs postulated throughout the plant" and that these analyses are for structures, systems, and components required to achieve safe shutdown. Further, the LAR indicates that "ongoing safety analysis work is in progress" for the main steam and "other" HELBs. On page 7, in the significant hazards consideration section, it states that "This report provides the completed analysis for ONS HELBs."

a) Specify for which unit the main steam analysis is in progress and the corresponding proposed changes. Also, specify which HELBs the word "other" on page 4 refers to.

b) Explain the apparent inconsistency between these statements (i.e. "ongoing" vs. "completed").

Duke Response to RAI 1

The Unit 1 LAR and the accompanying report ONDS-351, Rev.0, provided the analysis of HELBs postulated to occur throughout Unit 1 except those postulated breaks (in any system) that could affect the Main Steam pressure boundary. At the time of the submittal of the Unit 1 LAR, the safety analysis of possible affects to the reactor coolant system from any system postulated breaks that could affect the Main Steam pressure boundary was still in progress and thus the results of that analysis were not included in the Unit 1 LAR.

Subsequently, the safety analysis was completed. The safety analysis concluded that Main Steam Isolation Valves could be used to limit overcooling of the Reactor Coolant System following any postulated system break that could affect the Main Steam pressure boundary. A synopsis of this analysis, including the function of the Main Steam isolation valves to mitigate the event was provided in the Unit 3 LAR (see ONDS-351, Rev. 2, Sections 3.0 and 7.0).

RAI 2

The proposed LAR states that ONS' current regulatory criteria for HELB are in accordance with the provisions of the (1972-73) Giambusso/Schwencer letters. It also states that the proposed LAR, in addition to the Giambusso/Schwencer letters, will utilize Sections 3.6.1 and 3.6.2 of the Standard Review Plan (SRP) 1981 (NUREG-800 "Review of Safety Analysis Reports for Nuclear Power Plants") and Revision 2 of Branch Technical Position (BTP) Mechanical Engineering Branch (MEB) 3-1. It appears that the proposed LAR contains a mixture of various regulatory guidance to evaluate HELB from 1972 Giambusso letters, SRP 1981. Provide the following information:

a) Specify whether the proposed LAR meets all the criteria in BTP MEB 3-1, Rev. 2.

b) If not all of the criteria in BTP MEB 3-1, Rev. 2 are met, provide a detailed comparison of the full criteria contained in BTP MEB 3-1 with the ONS proposed LAR HELB criteria. In addition, for each deviation, provide a corresponding technical justification.

Duke Response to RAI 2

The Unit 1 LAR and the accompanying report ONDS-351, Rev.0 described the break and crack postulation methodologies which represented deviations from the requirements of the Giambusso/Schwencer letters. Where deviations to the Giambusso /Schwencer letters were described in the Unit 1 LAR, a comparison to the requirements of BTP MEB 3-1 Rev. 2 was made in an effort to show that the deviation(s) was (were) acceptable by comparison to HELB current day requirements. Oconee is not licensed to the Standard Review Plan (SRP), or to BTP MEB 3-1 and does not propose to be licensed as such in the future. However, in some cases BTP MEB 3-1 Rev. 2 provides more clarity than defined by Giambusso/Schwencer. Thus the LAR proposed adopting those rules from BTP MEB 3-1 Rev. 2 where more clarity was sought over the rules promulgated in Giambusso/Schwencer. This issue was previously discussed during the March 5, 2007 meeting between the NRC and Duke and a common understanding reached (Ref. 5: Matrix item H2).

For purposes of this discussion, there are two areas where BTP MEB 3-1, Rev. 2 provides more clarity than given by Giambusso/Schwencer: (1) Relaxation in Arbitrary Intermediate Pipe Rupture Requirements; and (2) Postulation of Critical Cracks. In general these are the two subjects where a deviation to Giambusso/Schwencer is sought by the HELB LAR(s). These topics are addressed below:

(1) <u>Relaxation in Arbitrary Intermediate Pipe Rupture Requirements</u>

Giambusso/Schwencer required for ASME Code Class 2 and 3 piping that intermediate break locations should be postulated as follows:

1) *At any intermediate locations between terminal ends where either the circumferential or longitudinal stresses derived on an elastically calculated basis under the loadings associated with seismic events and operational plant conditions exceed .8 x ($S_H + S_A$) or the expansion stresses exceed .8 S_A.*
2) *Intermediate locations in addition to those determined by (1) above, selected on a reasonable basis as necessary to provide protection. At a minimum, there should be two intermediate locations for each piping run or branch run.*

Generic Letter 87-11, allowed licensees to eliminate previously postulated arbitrary intermediate pipe breaks in Class 1 piping and Class 2 and 3 piping in areas of the plant outside the containment penetration areas without prior NRC approval insofar as the change did not conflict with the plant's license or the Technical Specifications. The GL implemented the relaxation by revising portions of the Branch Technical Position MEB 3-1 (Rev. 2), "Postulated Rupture Locations in Fluid System Piping Inside and Outside Containment."

The HELB LAR(s) proposes to adopt this provision to use stress criteria to postulate intermediate break locations for Class 2 and 3 piping, and eliminate arbitrary intermediate breaks. Intermediate break locations would be determined based on the calculated circumferential or longitudinal stresses derived on an elastically calculated basis using the loadings associated with seismic events and operational plant conditions that exceed .8 x (S_H + S_A). Intermediate break locations would not be postulated where the expansion stress exceed .8 S_A. Thermal stresses are classified as secondary, and taken in absence of other stresses, do not cause ruptures in pipes. Actual stresses used for comparison to the break thresholds will be calculated in accordance with the Oconee piping code of record, USAS B31.1.0[1]. Allowable stress values S_A and S_H shall be determined in accordance with the USAS B31.1.0 code or the USAS B31.7[2]

This proposal was first communicated in a letter dated July 3, 2002 to the NRC Document Control Desk. This provision is similar to that given in the BTP MEB 3-1 Rev. 2 Section B.1.c (2). The proposal to eliminate arbitrary intermediate breaks by the adoption of GL 87-11, and by reference BTP MEB 3-1 Rev. 2 Section B.1.c (2) has been previously approved for portions of the Low Pressure Injection System at Oconee Nuclear Station as part of the Passive Low Pressure Injection Cross Connection Modifications[3]. In addition, the approval to use BTP MEB 3-1 Rev. 2 Section B.1.c (2) has also been approved by the NRC for the following licensees:

a) Florida Power Corporation (Now Progress Energy), submittal for Crystal River Unit 3, dated December 18, 1989. The submittal was approved by the NRC on April 11, 1990.
b) Tennessee Valley Authority, Watts Bar Nuclear Plant Safety Evaluation Report Supplement 6 (SSER 6), Section 6, "Protection Against Dynamic Effects Associated with the Postulated Rupture of Piping, which was reviewed and approved by the NRC April 1991.
c) American Electric Power, Donald C. Cook Nuclear Plant, UFSAR Section 14.4.2.2.2, 'Design Basis Breaks.'

Although adoption of GL 87-11 implies a reduction in the number of break locations, inclusion of the proposed portions of BTP MEB 3-1 Rev. 2 in the Oconee HELB design and licensing basis will result in an actual increase in the number of postulated HELB locations outside containment when compared to the number postulated in the original HELB MDS OS-73.2 report. Each of these new locations will require that Oconee formulate a mitigation strategy. These actions will increase the ability of the plant to mitigate any break that could possibly occur. In doing this, the overall safety of the plant is improved.

As noted above, Oconee plans to adopt the provisions of BTP MEB 3-1 Rev. 2 regarding the elimination of arbitrary intermediate breaks for analyzed lines that include seismic loading. Adoption of this provision will allow Oconee to focus attention to those high stress areas that

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[1] USAS B31.1.0, 1967 Edition, "Power Piping"
[2] USAS B31.7, February 1968 Edition including Errata of June 1968, "Code for Pressure Boundary Piping, Nuclear Power Piping
[3] Reference SER dated 9/29/2003.

have a higher potential for catastrophic pipe failure. Breaks for analyzed lines that do not contain seismic loading and breaks for non-analyzed lines will be postulated at every piping weld and fitting. The inclusion of these strategies will provide a comprehensive break scenario for which mitigation strategies will be determined. These actions can only increase the overall safety of the plant.

(2) Postulation of Critical Cracks

The requirement to postulate critical cracks was provided in the Schwencer errata letter dated January 17, 1973. The requirement was identified as follows: 1. Page 2, Item 2 – Insert the following in 2. To precede the existing sentence:

> *"Design basis break locations should be selected in accordance with the following pipe whip protection criteria; however, where pipes carrying high energy fluid are routed in the vicinity of structures and systems necessary for safe shutdown of the nuclear plant, supplemental protection of those structures and systems shall be provided to cope with the environmental effects (including the effects of jet impingement) of a single postulated open crack at the most adverse location(s) with regard to those essential structures and systems, the length of crack being chosen not to exceed the critical crack size. The critical crack size is taken to be ½ the pipe diameter in length and ½ the wall thickness in width."*

Oconee proposes to eliminate the postulation of critical crack(s) in those seismically analyzed systems where the calculated primary plus secondary stress falls below the threshold of .4 x (S_H + S_A). There are three high energy systems that are seismically analyzed to which the elimination of the postulation of critical crack request applies: Main Steam (MS), Main Feedwater (MFDW), and High Pressure Injection (HPI). The MS and MFDW Systems are located in both the Turbine Building (TB) and Auxiliary Building (AB). The HPI System is located in the AB. None of these systems are located in the Standby Shutdown Facility (SSF).

The proposal to eliminate 'arbitrary critical crack' locations is based on a logical extension of the rationale to eliminate arbitrary intermediate break locations. As noted above, GL 87-11 allowed the elimination of the postulation of intermediate break locations based on the calculated primary plus secondary stress falling below the threshold of .8 x (S_H + S_A). It follows then that the justification for eliminating the postulation of intermediate break locations could likewise apply to the elimination of critical crack locations. That is, it allows Oconee to focus attention on those medium stress areas of the plant that have a higher potential for leakage cracks to form and exclude those that have a lower potential.

The overall HELB mitigation strategy is based on the crediting of systems and equipment to reach a Safe Shutdown Condition located remote from the postulated break or crack location(s). The mitigation strategy for breaks or cracks postulated to occur in the TB would be based on systems and equipment located in the AB or the SSF to reach a Safe Shutdown Condition. Similarly, the mitigation strategy for breaks or cracks postulated to occur in the AB would be based on systems and equipment located in the TB or the SSF to reach a Safe Shutdown

Condition. Since a barrier wall separates the TB from the AB, the environmental conditions that could occur in the TB following a postulated break or crack will not affect systems and equipment located in the AB credited to mitigate the event. Since the SSF is remote from the TB, environmental conditions in the TB would not affect systems and equipment located in the SSF credited to mitigate the event. In the same way, environmental conditions that could occur in the AB following a postulated break or crack will not affect systems located in the TB or the SSF credited to mitigate the event. A further enhancement is provided for portions of the MS and MFDW Systems located in the AB. These systems receive periodic volumetric inspections at all accessible girth weld locations and adjacent base metal to provide early warning of potential degradation in these systems that might result in the formation of a break or crack.

Thus the proposal for eliminating the postulation of 'arbitrary critical crack' locations is justified by the small subset of high energy systems to which the elimination would apply, by the logical extension of the NRC justification that allowed the elimination of the postulation of arbitrary intermediate breaks, and by the mitigation strategy that credits separation between the break or crack location and the systems and equipment required to mitigate the event.

RAI 3

Revision 2 of BTP MEB 3-1, Section B.2.e, "Fluid Systems Qualifying as High-Energy or Moderate Energy," and Footnote 5 refer to "short operational period" requirements where "leakage cracks instead of breaks may be postulated." The footnote in Section B.2.e states:

> "The operational period is considered "short" if the fraction of time that the system operates within the pressure-temperature conditions specified for high-energy fluid systems is about 2 percent of the time that the system operates as a moderate-energy fluid system (e.g., systems such as the reactor decay heat removal system qualify as moderate-energy fluid systems; however, systems such as auxiliary feedwater systems operated during PWR reactor startup, hot standby, or shutdown qualify as high-energy fluid systems)."

It appears that the proposed LAR utilizes this part of the SRP to reduce the number of the HELB locations. The proposed LAR has the following statements:

> "HELBs and Critical Cracks are not postulated on HE [high energy] Lines that operate at HE conditions less than 2% of the total system operating time." (Ref.: LAR Encl. 3, pg. 2-2)

And

> "HELBs and Critical Cracks are not postulated on HE Lines that operate at HE conditions less than 1% of the of the total plant operating time (Normal Plant Conditions)". (Ref. LAR Encl. 3, pg 2-2)

And that

> "For systems meeting these limitations, no breaks or cracks are postulated." (Ref. LAR Encl. 3, pg. 8-1)

a) The criterion sited in the second LAR paragraph above (with reference to the 1% time) is not contained in the ONS current regulatory criteria (Giambusso/Schwencer letters) or in any of the proposed LAR referenced SRP editions. Provide your basis and acceptable justification for the short period of operation definition sited in that paragraph. Also, list all locations where this criterion has been applied in order to reduce the number of HELB locations.

b) Per the LAR criteria sited above, breaks or cracks are not postulated on lines meeting the short period of operation criterion. The SRP guidance is to postulate through-wall leakage cracks in lieu of breaks for those lines that qualify for the short operational period criterion as stated in the SRP. Provide a technical justification for the apparent deviation. In addition, provide a list of piping systems or sections of piping systems that fall under this requirement, your method of evaluation and whether through-wall leakage cracks have been postulated at those locations, and the corresponding assessment resulting from these leakage crack postulations.

c) State whether the proposed LAR fully satisfies Footnote 5 of MEB 3-1 in that systems such as auxiliary feedwater systems operated during PWR reactor startup, hot standby, or shutdown have been evaluated as high-energy fluid systems, as specified in the footnote.

Duke Response to RAI 3(a)

Duke recognizes that the 1% criterion is not contained in Giambusso/Schwencer or the Standard Review Plan. The proposal to exempt consideration of breaks in high energy systems or subsystems that operate for short periods of time at high energy conditions is based on the probability of a pipe break actually occurring during this short operational period and to a lesser extent, precedent established in other licensee submittals. This issue was previously addressed in the March 5, 2007 meeting between the NRC and Duke and a common understanding reached (Ref. 5: Matrix item H3).

The probability that high energy piping would fail in a given year is on the order of 1×10^{-4}. Should the high energy system or subsystem operate less than 1% of the time in a given year, then the probability that the piping would fail in a given year equates to 1×10^{-6}. The overall objective of the break and crack postulation criteria contained in the HELB LAR(s) is to identify those locations that have a higher probability of failure and determine the mitigation strategies necessary to reach safe shutdown. Other locations such as those contained within systems that operate a high energy conditions for short periods of time have a lower probability of failure and as such should be discounted.

The exemption of the postulation of breaks for those high energy systems or subsystems that operate at high energy conditions for less than 1% of the total time during Normal Plant Conditions was also based on pipe rupture licensing basis information reviewed from other licensees. Specifically, the Millstone Unit 2 document, "Pipe Rupture Analysis Criteria outside the Reactor Building," notes in Section 3.3., "HE (High Energy) Systems may also be classified as moderate energy if the total time of system operation is less than 1% of the total plant operating time."

Another example in this regard is located in an Appendix to the FSAR for Tennessee Valley Authority's Watts Bar Nuclear Plant. Specifically Appendix 3.6A Definition 6 notes in part:

"Systems may be classified as moderate energy if the total time that the above conditions are exceeded is less than either of the following:

a. One percent of the normal operating life span of the plant
b. Two percent of the time period required for the system to accomplish its design function."

Finally, the Oconee HELB LAR(s) provides a comprehensive evaluation of safe shutdown requirements for a substantial number of postulated breaks located throughout the plant. Based on the number of breaks described in the analysis, Oconee is confident that all significant high energy break scenarios have been considered. As such, the postulation of a break in high energy systems or a subsystem that doesn't normally operate, or operate infrequently is not necessary.

The 1% time exclusion has been applied to certain high energy systems that are provided for emergency situations. These systems are not normally in operation. However, the systems are routinely tested to verify their capability to perform their accident mitigation functions. The interval of time in which the system is pressurized is limited in duration (well below the 1% plant operating time). Combining the low probability of the high energy line break with the limited duration of the system being in a high energy state, the probability of a line break is sufficiently low to exclude the system from the postulation of a high energy line break. The 1% exclusion was applied to the following emergency systems:

- Reactor Building Spray (entire system)
- "B" Train of High Pressure Injection ("C" HPI Pump Discharge to RB Penetration)
- Emergency Feedwater (EFW) System (entire system)
- Standby Shutdown Facility Auxiliary Service Water System (entire system)

A historical review of these systems was performed to validate operating times of the above systems in accordance with the common understanding reached (Ref. 5: Matrix item H3). Plant data was reviewed from January 2005 to April 2009 and showed that the systems had been operated well below 1% of the Normal Plant Conditions. The EFW system is not normally operated during startup and shutdown evolutions, except for testing. However, the system may be operated for filling the steam generators to wet layup conditions when the affected unit's condensate and feedwater system has been shutdown. This is of a short duration as well. With the inclusion of this operating time, the EFW system operating time remains well below the 1% value.

Duke Response to RAI 3(b)

Giambusso/Schwencer does not require the postulation of critical cracks in moderate energy systems.

The following systems (and portions of systems) were downgraded from high energy systems and excluded from HELB postulation:

1. Low Pressure Injection System (entire system)
2. Condensate Recirculation Piping to the Upper Surge Tank
3. Main Feedwater Pump Recirculation Piping to the Main Condenser
4. Main Feedwater Cleanup Piping to the Upper Surge Tank
5. Main Feedwater to the Steam Generator Auxiliary Feedwater Nozzles
6. Steam Generator Hot Blowdown/Drain Piping
7. Turbine Bypass Valve Discharge Piping to the Main Condenser

A historical review of the systems being downgraded from high energy was performed to validate operating times at high energy conditions in accordance with the common understanding reached (Ref. 5: Matrix item H3). Plant startup and shutdown data was reviewed for the following periods:

- For Unit 1: From 7/8/1999 to 6/1/2008
- For Unit 2: From 12/16/1999 to 12/12/2008
- For Unit 3: From 5/21/2000 to 11/11/2008

1. Low Pressure Injection System (entire system)

   This system is normally isolated from the Reactor Coolant System (RCS) by closed motor-operated valves. The system is charged from the Borated Water Storage Tank (BWST) by two normally open motor-operated valves. The system is normally pressurized by the head of the BWST. Both the pressure from the BWST and the temperature in the system are below the threshold for high energy conditions. During the latter stages of plant cool-down, the system is placed into service by isolating the system from the BWST and opening the isolation valves from the RCS. The RCS is aligned to the LPI system after RCS pressure has been reduced to approximately 300 psig and RCS temperature has been reduced below 250 deg. F. This subjects the LPI system to high energy conditions until the RCS is cooled to 200 deg. F (or below) and depressurized to 275 psig (or below). Likewise, during the initial stages of RCS heat-up and pressurization for unit startup activities, the LPI system is aligned to the RCS where conditions subject the LPI system to high energy conditions. The total time the LPI spends in high energy conditions is typically short in duration. A historical review was performed for startup/shutdown evolutions on all 3 units using Operator Aid Computer (OAC) data to quantify the "short periods of time" while subjected to high energy conditions. The LPI system on each unit was subjected to high energy conditions less than 1% of the time for the period reviewed.

2. Condensate Recirculation Piping to the Upper Surge Tank

   This section of piping is normally isolated from the high energy portion of the Condensate system by a closed motor-operated valve. The valve is opened for short periods of time during unit startup to establish cleanup of the condensate system. A historical review was performed for startup evolutions on all 3 units using OAC data to quantify the "short periods of time" while subjected to high energy conditions. The Condensate Recirculation piping on each unit was subjected to high energy conditions for less than 1% of the time for the period reviewed.

3. Main Feedwater Pump Recirculation Piping to the Main Condenser

   Each Main Feedwater pump is equipped with a minimum recirculation line that directs flow to the main condenser. There are two lines per unit routed to separate condenser sections. Both of the recirculation lines are normally isolated from the high energy portion of the Feedwater system by a closed air-operated valve. The piping is under vacuum conditions during normal operation while the valve is closed. The valve is throttled open for short periods of time during unit startup and shutdown when required flow to the steam generators is below the minimum required flow for an operating main feedwater pump. The total time the recirculation piping spends in high energy conditions is typically short in duration. A historical review was performed for startup and shutdown evolutions on all 3 units using OAC data to quantify the "short periods of time" while subjected to high energy conditions. The total time the Main Feedwater pump recirculation lines to the condenser was subjected to high energy conditions was approximately 2% of the time period reviewed for each unit.

4. Main Feedwater Cleanup Piping to the Upper Surge Tank

   Each Main Feedwater header is equipped with a recirculation line that directs flow to a single line to the Upper Surge Tank to aid in cleanup of the system. Each of the recirculation lines is normally isolated from the high energy portion of the Feedwater system by two closed motor-operated valves. The valves are opened for short periods of time during unit startup and shutdown when feedwater cleanup is desired. The total time the feedwater cleanup piping spends in high energy conditions is typically short in duration. A historical review was performed for startup evolutions on all 3 units using OAC data to quantify the "short periods of time" while subjected to high energy conditions. The total time the feedwater cleanup line to the Upper Surge Tank was subjected to high energy conditions was less than 2% of the time period reviewed for each unit.

5. Main Feedwater to the Steam Generator Auxiliary Feedwater Nozzles

Each Main Feedwater header is equipped with a line that directs flow to the auxiliary nozzles of the associated steam generator. These lines are normally isolated from the high energy portion of the Feedwater system by a closed motor-operated valve. The valves are equipped with an automatic signal to open the valves on a loss of all four reactor coolant pumps or a loss of both main feedwater pumps. In addition, the valves may be opened during startup and shutdown evolutions. The total time the feedwater piping to the auxiliary nozzles spends in high energy conditions is typically short in duration. A historical review was performed for startup and shutdown evolutions on all 3 units using OAC data to quantify the "short periods of time" while subjected to high energy conditions. The total time the main feedwater lines to the auxiliary nozzles were subjected to high energy conditions was less than 1% of the time period reviewed for each unit.

6. Steam Generator Hot Blowdown/Drain Piping

Each steam generator is equipped with a blowdown line that directs flow to the main condenser. Both of the blowdown lines are normally isolated from the high energy portion of the steam generators by closed manually operated valves located inside the reactor building. During unit startup, it is desired to establish steam generator blowdown to control the water chemistry inside the steam generators. The total time the steam generator blowdown piping spends in high energy conditions is typically short in duration. A historical review was performed for startup and shutdown evolutions on all 3 units using OAC data to quantify the "short periods of time" while subjected to high energy conditions. The total time the steam generator blowdown lines were subjected to high energy conditions was less than 2% of the time period reviewed for each unit.

7. Turbine Bypass Valve Discharge Piping to the Main Condenser

There are four turbine bypass valves (two per steam generator) that are normally closed. The discharge of each turbine bypass valve is connected to a common discharge header. The common discharge header is then divided into three lines that are directed to the main condenser (one line per condenser). During normal operation, these lines are subjected to vacuum conditions. Following a main turbine trip or planned shutdown of the main turbine, the TBVs open as necessary to control main steam pressure at the desired setpoint. The TBVs are utilized to cool the RCS down to LPI entry conditions. During startup evolutions, the TBVs are initially opened to pull a vacuum on the steam generators. Once RCS heat-up is commenced, the TBVs would be closed to allow the heat-up to continue. The TBVs may be throttled open during periods of startup where the heat-up process is placed on hold. The TBVs are also throttled open during reactor power increases until the main turbine is placed online. A historical review was performed for startup and shutdown evolutions on all 3 units using OAC data to quantify the "short periods of time" while subjected to high energy conditions. The total time the TBV discharge lines were subjected to high energy conditions was approximately 2% of the time period reviewed for each unit.

No through-wall leakage cracks have been postulated for high energy systems (or portions of high energy systems) that have been downgraded using the 2% operating time at high energy conditions.

Duke Response to RAI 3(c)

The responses in 3(a) and 3(b) describe the criteria used by Duke in eliminating piping from high energy considerations; Therefore, Footnote 5 of MEB 3-1 is not applicable to the LAR in accordance with the common understanding reached (Ref. 5: Matrix item H3).

RAI 4

Enclosure 3 contains HELB criteria in Sections 2.2 and 8. Some of these criteria are not consistent. The following is brought to your attention as examples:

Page 8-2 under paragraph letter "C" states that:

> "...For unanalyzed branch connections or where the stress at the branch connection is not accurately known, break locations are postulated in accordance with BTP MEB 3-1 (Section B.I.c (3))."

Page 8-2 under paragraph letter "B" states that (similarly, "F" which refers to "B"):

> "For piping that is not rigorously analyzed or does not include seismic loadings, intermediate breaks are postulated in accordance with BTP MEB 3-1 (Section B.1.c (3)) (Reference 10.1.5)."

Last bulleted paragraph of page 2-2 states that:

> "For piping that is not rigorously analyzed or does not include seismic loadings, HELBs shall be postulated at the terminal ends, and intermediate break locations as provided in BTP MEB 3-1, Section B.l.c.(2)(b)(i). (References 10.1.5, 10.1.6, & 10.1.7)."

a) The NRC staff accepts the position taken in the paragraph of page 2-2, above, as it is in accordance with the criteria of MEB 3-1 (LAR Ref 10.1.5) Section B.l.c. (2)(b)(i). In addition, it is noted that Section B.l.c.(3)(a)(2) of the referenced MEB 3-1 states that: "Where break locations are selected without the benefit of stress calculations, [circumferential] breaks should be postulated at the piping welds to each fitting, valve, or welded attachment." Please explain the apparent inconsistency between the above cited statements.

b) Provide the criteria for non-seismic I category piping and its interaction with seismic I category piping and how these criteria have been implemented.

c) Identify areas where the criteria are inconsistent within the proposed LAR.

Duke Response to RAI 4(a)

The reference on page 8-2 to BTP MEB 3-1 Section B.1.c. (3) is incorrect as stated in the Unit 1 HELB LAR. It has been subsequently corrected in the Unit 3 HELB LAR to reference BTP MEB 3-1 Section B.1.c (2)(b)(i).

Duke Response to RAI 4(b)

The Oconee UFSAR Section 3.7.3.9 notes that "seismic / non seismic lines are physically separated insofar as possible such that failure of a non seismic line has no effect on safety related piping." The HELB LAR(s) identify certain cases where a postulated break location of a non seismic system or subsystem may interact with and possibly cause failure of a seismically supported system. These potential interactions were discovered in the Turbine Building (TB). These postulated interactions were based on field surveys of the plant, using experienced engineers. Conservative concepts were employed during the field surveys, with the resulting worst case assessment of potential interactions. As noted before, the overall mitigation strategy is predicated on separation of essential systems (e.g., those systems and components necessary to reach a Safe Shutdown Condition) from the postulated high energy line break. For breaks postulated to occur in the TB, systems and components located in the Auxiliary Building (AB) or the Standby Shutdown Facility (SSF) would be available for mitigation of the effects from the break. For breaks postulated to occur in the AB, systems and components located in the TB or SSF would be available for mitigation of the effects from the break. As shown in the ONDS-351, Rev. 2 report, any possible interactions between non seismic piping and seismic piping located in the TB can be adequately mitigated with available equipment in either the AB or the SSF.

As noted above, the identified potential interactions between non seismic and seismic piping are located in the Turbine Building, between the various secondary side high energy systems and portions of the following systems:

- Emergency Feedwater System
- Main Steam Branch lines
- Siphon Seal Water System
- Condenser Cooling Water
- Low Pressure Service Water System.

Duke Response to RAI 4(c)

Duke is not aware of any other HELB criteria that are inconsistent with the proposed LAR.

RAI 5

Enclosure 3, page 8-1, contains the following statement:

> "Gas systems (e.g. nitrogen) and oil systems (e.g. EHC) have been excluded [from HELB and leakage crack considerations], since these systems possess limited energy (Reference 10.3.17)."
>
> Page 2-1 also indicates that these systems (see above) "are not defined as high energy systems."

HELB Report, OS-73.2 titled, "Analysis of Effects Resulting from Postulated Piping Breaks Outside Containment for Oconee Nuclear Station, Units 1,2, & 3," is the original basis for the ONS HELB evaluation, included the Electro-Hydraulic Control and Nitrogen systems as postulated pipe breaks. Please address this departure from the previously approved evaluation.

Duke Response to RAI 5

The Nitrogen and Electro-Hydraulic Control (EHC) systems were within the original scope of HELB postulation. There were no breaks postulated that could impact structures, systems, or components that could adversely affect the operation of the Reactor Coolant System (ref. Table 2.1-1 in MDS Report OS-73.2). These systems were excluded from the HELB reconstitution project due to the limited energy of the piping. This was based primarily on the small diameter piping in these systems. The nitrogen system consists of a high pressure portion and a low pressure portion. The low pressure portion is not considered to be high energy due to the pressure being below 275 psig. The high pressure portion is normally pressurized to approximately 625 psig. However, most of the piping is 1-inch or less excluding it from break postulation. A small section of 1.5-inch (OD) piping is routed inside the turbine building basement. Any break in this section of piping is judged to have insufficient energy to damage adjacent piping systems or structural components. There are two locations inside the Auxiliary Building on the 2nd Floor hallway (one at the north end and one at the south end) where the high pressure nitrogen piping increases in size from 1-inch (OD) to 2-inches (OD) to accommodate a pressure reducing valve. A break in this section of piping is judged to have insufficient energy to damage adjacent piping systems or structural components. The EHC system also consists of a high energy portion and low energy portion. The low pressure portion is not considered to be high energy due to the pressure being below 275 psig. The high pressure portion is normally pressurized to approximately 1600 psig. The high energy portion contains piping that is 1-inch and 1.5-inch nominal pipe size. Again, due to the small diameter piping, it is judged that there would be insufficient energy to damage adjacent piping systems or structural components.

RAI 6

The definition of terminal end on pages 1-12 and 8-2 paragraph "C" deviates from the cited SRP reference, specifically with regard to boundary valves. The eighth bulleted paragraph on Page 2-2 provides the proposed LAR criterion for closed valves on seismically analyzed pipe runs. This LAR cited criterion is not in accordance with SRP.

a) Discuss the inconsistency between your definition of terminal end with that of the SRP and address the exclusion of treating boundary valves as terminal ends.

b) In addition, provide a list of valves and piping runs for which terminal end postulation of HELB have been excluded due to this definition.

Duke Response to RAI 6(a):

This issue was previously discussed in the March 5, 2007 meeting between the NRC and Duke. It was agreed during the meeting that a common understanding had been reached and that no further action was required by Duke (Ref. 5: Matrix item H4).

The Giambusso/Schwencer letters do not directly address the postulation of terminal end breaks in Class 2 and 3 piping at isolation valves that separate high energy systems or subsystems from non high energy systems or subsystems. However, Giambusso/Schwencer does address the postulation of terminal end breaks at isolation valves for Class 1 piping. Footnote 3 under Giambusso 2(a) notes the following:

> *"A piping run interconnects components such as pressure vessels, pumps, and rigidly fixed valves that may act to restrain pipe movement beyond that required for design thermal displacement. A branch run differs from a piping run only in that it originates at a piping intersection, as a branch of the main pipe run."*

As noted before for HELB, Oconee is not licensed to the SRP or BTP MEB 3-1, and does not seek to be licensed as such in the future. However for purposes of discussion, Footnote 3 of Section B.1.c. (1)(a) of BTP MEB 3-1 Rev. 2 notes the following:

> *"Extremities of piping runs that connect to structures, components (e.g., vessels, pumps, valves), or pipe anchors that act as rigid constraints to piping motion and thermal expansion. A branch connection to a main piping run is a terminal end of the branch run, except where the branch run is classified as part of the main run in the stress analysis and is shown to have a significant effect on the main run behavior. In piping runs which are maintained pressurized during normal plant conditions for only a portion of the run (i.e., up to the first normally closed valve) a terminal end of such runs is the piping connection to this closed valve."*

Note that the first part of the footnotes are similar in that both define terminal ends as structures (including pipe anchors) and components that act to restrain pipe motion and thermal expansion.

However, the BTP MEB 3-1 Rev. 2 footnote expands the definition beyond that provided in Giambusso/Schwencer to include isolation valves that separate piping that is normally maintained at high energy conditions from other piping that is not normally maintained at high energy conditions.

The HELB LAR(s) fully meet the requirements of Giambusso/Schwencer in this regard. Giambusso/Schwencer required the postulation of terminal end breaks at rigidly fixed valves that may act to restrain thermal movement. There are no such rigidly fixed isolation valves that serve as the boundary between high energy systems or subsystems and the non high energy systems or subsystems at Oconee. All isolation valves that serve in this manner are in line valves that are not independently supported or supported in a way that would prohibit piping motion and thermal movement.

As noted in the accompanying report to the LAR (ONDS-351, Rev. 2), the applicable high energy piping systems at Oconee are denoted as those systems or subsystems that are rigorously analyzed for applicable design loads, including seismic, those systems or subsystems that are not rigorously analyzed, and those systems or subsystems that are rigorously analyzed, but are not analyzed for seismic loads. For those systems or subsystems that are rigorously analyzed for the applicable design loads, including seismic, and the analyses are continuous across the subject isolation valves such that accurate stress information is available, breaks are postulated at locations where the actual calculated primary stress (longitudinal pressure + gravity + Operational Basis Earthquake) + secondary stress (thermal movement, anchor motions, etc.) exceed the stress threshold given in BTP MEB 3-1 Rev. 2 Section B.1.c(2). For all other systems or subsystems, breaks are postulated to occur at all welds and fittings.

The justification for not postulating breaks at isolation valves between high energy piping and non high energy piping for those systems or subsystems that are rigorously analyzed for the applicable design loads, including seismic, is based on the similarities between a branch connection that is appropriately analyzed in the stress analysis and a closed isolation valve that is appropriately analyzed in the stress analysis. As noted in the footnote, the branch side of a connection is a terminal end unless it is classified as part of the main run in the stress analysis and is shown to have a significant effect on the main run behavior. Applying that rationale to a closed valve that represents the boundary between high energy piping and non energy piping would lead one to conclude that if such a valve was classified as part of the main run in the stress analysis and shown to have a significant effect on the main run behavior, then the valve would not represent a terminal end. In the stress analysis, the appropriate design parameters are applied such that the lower pressure is applied to the non high energy piping and the higher pressure to high energy piping. Given these facts, Duke concludes that these valves do not represent a terminal end.

The NRC has previously approved this interpretation at Oconee Nuclear Station for the Passive Low Pressure Injection Cross Connection Modifications[4].

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[4] Reference SER dated 9/29/2003.

Other licensees have reached the same conclusion. Two examples are included below:

Florida Power Corporation (now Progress Energy) submitted a revised pipe rupture analysis criteria for Crystal River Unit 3 by letter dated March 31, 1989 and later revised by letter dated December 18, 1989. Page 7 of the pipe rupture analysis criteria report defines a terminal end as:

> *"Extremities of piping runs that connect structures, large components (e.g., vessels, pumps) or pipe anchors that act as essentially rigid constraints to piping thermal expansion including rotational movement from static or dynamic loading. In line fittings such as valves, adequately modeled and not anchored in the piping stress analysis, are not terminal ends."*

The NRC accepted the new licensing basis for pipe rupture for Crystal River Unit 3 by letter dated April 11, 1990.

In Tennessee Valley Authority's Watts Bar FSAR Section 3.6.A.2, "Determination of Break Locations and Dynamic Effects Associated with the Postulated Rupture of Piping," Subsection 3.6.A.2.1.2.3, "High/Moderate Energy Interfaces," reads as follows:

> *"Line supported valves sometimes form the interface between high energy lines and moderate energy lines. In this case, the fixity as implied in the word terminal does not exist at the line supported valve. This condition is treated as if there were no terminal (end).."*

Duke Response to RAI 6(b)

Unit 1

Feedwater System (Reference ONDS-351, Rev. 2, Figure 4.1-4, Sheets 3 & 4)

1FDW-38	1FDW-47	1FDW-374	1FDW-94	1FDW-97	1FDW-98
1FDW-96	1FDW-384				

High Pressure Injection (Reference ONDS-351, Rev. 2, Figure 4.1-7, Sheets 1 through 4)

1HP-116	1HP-409	1HP-42	1HP-41	1HP-62

Main Steam (Reference ONDS-351, Rev. 2, Figure 4.1-8, Sheets 3 through 5)

1MS-153	1MS-155	1MS-22	1MS-19	1MS-28	1MS-31
1MS-38	1MS-37				

Unit 2

Feedwater System (Reference ONDS-351, Rev. 2, Figure 5.1-4, Sheets 3 & 4)

2FDW-38 2FDW-47 2FDW-99 2FDW-101

High Pressure Injection (Reference ONDS-351, Rev. 2, Figurc 5.1-7, Sheets 1 through 4)

2HP-116 2HP-409 2HP-42 2HP-41 2HP-62

Main Steam (Reference ONDS-351, Rev. 2, Figure 5.1-8, Sheets 3 through 5)

2MS-153 2MS-155 2MS-22 2MS-19 2MS-28 2MS-31
2MS-38 2MS-37

Unit 3

Feedwater System (Reference ONDS-351, Rev. 2, Figure 6.1-4, Sheets 3 & 4)

3FDW-38 3FDW-47 3FDW-99 3FDW-101

High Pressure Injection (Reference ONDS-351, Rev. 2, Figure 6.1-7, Sheets 1 through 4)

3HP-116 3HP-409 3HP-42 3HP-41 3HP-62

Main Steam (Reference ONDS-351, Rev. 2, Figure 6.1-8, Sheets 2 through 4)

3MS-153 3MS-155 3MS-22 3MS-19 3MS-28 3MS-31
3MS-38 3MS-37

RAI 7

Enclosure 3, 8-2, paragraph "C" states that:

> *"A branch appropriately modeled in a rigorous stress analysis with the run flexibility and applied branch line movements included and where the branch connection stress is accurately known, the stress criteria noted above is used for postulating breaks locations."*

MEB 3-1, R2, B.1.c (1) (a) Footnote 3, states that:

> *"A branch connection to a main piping run is a terminal end of the branch run, except where the branch run is classified as part of a main run in the stress analysis <u>and</u> is shown to have a significant effect on the main run behavior."*

According to the proposed LAR criterion, branch runs analyzed as part of a main run and do not significantly affect the main run, their connections are not considered terminal end and depending on the stresses, their connection to the main run may not be postulated for pipe break. This is inconsistent with the MEB 3-1 criterion. Provide a technical justification for the sited departure from the MEB 3-1 criterion for branch runs.

Note: RAIs 7 and 8 are on branch connections and valves. The staff has, in the past, asked Duke to clarify that it will satisfy the complete criteria contained in Footnote 3 of BTP MEB 3-1. It does not appear that this has taken place in the proposed LAR. In addition, the staff has previously requested Duke to compare its proposed HELB criteria with the full criteria contained in BTP MEB 3-1 in order for the staff to perform a thorough safety review of the Duke HELB proposal. The proposed LAR only addresses the criteria from BTP MEB 3-1, which provides relaxations to the Oconee licensing basis HELB criteria.

Duke Response to RAI 7

The statement in Enclosure 3 (ONDS-351, Rev. 2), page 8-2, paragraph C indicates that if the branch connection stress is accurately known, the stress criterion is used for postulating break locations. In order for the branch connection stress to be accurately assessed, the branch line must be included in the stress model of the main run. So this statement is not incompatible with BTP MEB 3-1 Rev. 2 Section B.1.c. (1)(a) Footnote 3. In those cases where the branch line is included in the stress model of the main run, the branch line is classified as part of the main run and by its inclusion, has a significant effect on the main run behavior. For those cases where the branch line is not included in the stress model of the main run, terminal end breaks are postulated on the branch side of the connection.

To view the response regarding postulation of breaks at isolation valves separating high energy systems or subsystems from non high energy systems or subsystems, see Duke's response to RAI 6(a) above.

RAI 8

Page 8-3 states that, "Dynamic analysis of High Energy Category 1 piping postulated break locations and the effect on associated supports was not accomplished at Oconee." This does not meet the provisions of the Giambusso letter which specify that a summary be provided for the dynamic analysis applicable to the design of Category 1 piping and associated supports which determine the resulting loadings. Please address this apparent departure from the Giambusso letter.

Duke Response to RAI 8

Giambusso/Schwencer does not define the meaning of High Energy Category 1 piping. If High Energy Category 1 piping means Class 1 piping, no dynamic analysis is required since there is no Class 1 piping outside containment at Oconee Nuclear Station. Should High Energy Category 1 piping mean piping that is indirectly connected to the primary system (Reactor Coolant

System), such as Main Feedwater and Main Steam, or if High Energy Category 1 piping means safety related piping, then the statement on page 8-3 of ONDS-351, Rev. 2 prior to the statement cited in the NRC RAI provides clarification that dynamic analyses were performed for postulated pipe ruptures in the East Penetration Room to determine the internal pressurization of the room.

The Giambusso letter attachment 1, "General Information Required for Consideration of the Effects of a Piping System Break outside Containment" noted on page 1 the following:

> *"Since piping layouts are substantially different from plant to plant, applicants and licensees should determine on an individual plant basis the applicability of each of the following items for inclusion in their submittals."*

The response in ONDS-351, Rev. 2 indicates that dynamic analyses were performed for the break scenarios that warranted a dynamic analysis, but not for the break scenarios that did not warrant a dynamic analysis. For example, dynamic analyses were not required for breaks postulated to occur in the Turbine Building to determine internal pressurization, since the volume of the building is large and contains numerous openings, such that internal pressurization of the building is insignificant. However where the room is small and contain no significant openings, as is the case for the East Penetration Room and the Ventilation Equipment Rooms of the Auxiliary Building, dynamic analysis were performed to determine the internal pressurization of the room. So dynamic analyses were performed for those scenarios where such an analysis was required.

RAI 9

In reference to the main feedwater (MFDW) rupture restraint, page 8-4 states that "No breaks are postulated immediately downstream of the structural anchor." Terminal ends are on both sides of the anchors and breaks should be postulated on both sides.

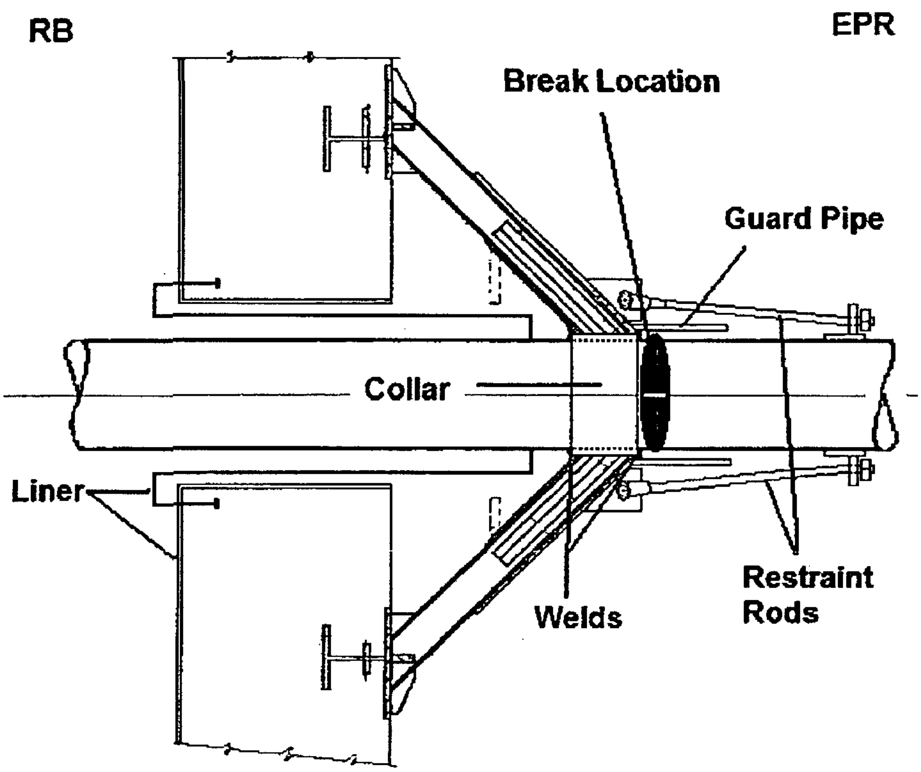
a) Provide an acceptable justification for not postulating breaks on both sides of this anchor.

b) Please describe the consequences of the terminal end failure of the feedwater system within the auxiliary building that could occur on the reactor building side of the rupture restraint. Provide an analysis supporting this description.

c) List any other inline anchors where breaks have been postulated on one side only.

Duke Response to RAI 9(a)

The postulated break location at the MFDW rupture restraint remains unchanged from the original MDS Report No. OS-73.2. The Atomic Energy Commission (AEC) previously accepted the report with the break location at the MFDW rupture restraint as shown on Figure 2.1-4.c of the report. A detailed sketch, showing the rupture restraint and the original postulated break location follows.



Sketch RAI-9(a)

Duke Response to RAI 9(b)

The intent of the original MDS Report (OS-73.2) was to address high energy line breaks occurring outside containment. The postulated terminal end breaks at containment penetrations given in this report were located on the Auxiliary Building (AB) side of the penetration. Breaks on the Reactor Building (RB) side of the penetration were not included in the report. All of the containment penetrations at Oconee are of the fixed design, and as such, act as terminal ends. So any postulated break at the containment penetrations (at the terminal end) would result, by definition, in a loss of containment integrity. Any of these breaks would be similar to a break inside containment. Similarly, a postulated break location downstream of the MFDW rupture restraint would be similar to a MFDW break inside containment, except that a localized failure of containment would also occur. The design basis of containment penetrations is given in UFSAR Section 3.6.1.1. The section states the following:

1) *All penetrations are designed to maintain containment integrity for any loss of coolant accident combination of containment pressures and temperatures.*

2) *All penetrations are designed to withstand line rupture forces and moments generated by their own rupture as based on their respective design pressures and temperatures.*
3) *All primary penetrations and all secondary penetrations that would be damaged by a primary break are designed to maintain containment integrity.*
4) *All secondary lines whose break could damage a primary line and also breach containment are designed to maintain containment integrity.*

The statements of interest are numbers 2 & 4 above. Statement 2 means that the MFDW rupture restraint can withstand the associated rupture forces associated with a break on either side of the restraint. Statement 4 means that should the MFDW line break downstream of the rupture restraint or inside containment, a primary line will not be affected.

Duke Response to RAI 9(c)

This issue was previously discussed during the March 5, 2007 meeting between the NRC and Duke and a common understanding reached (Ref. 5: Matrix item H7)

As noted in the response to RAI 9(b) above, the containment penetrations containing high energy lines are of the fixed design, and thus any postulated break at a containment penetration terminal end would result in a loss of containment integrity. Postulated breaks at containment penetrations reported in MDS Report No. OS-73.2, were shown on the AB side of the containment penetration. And as noted before, the AEC previously approved MDS Report OS-73.2, including the postulated break locations. ONDS-351, Rev. 2 does not seek to change the locations of postulated breaks at containment penetrations.

RAI 10

In reference to the postulated main steam pipe break in the east penetration room (1-MS-065), this break is not postulated at the terminal end which is the anchor point. It is indicated on page 4-8 that the break is postulated in the piping run outside the containment wall and remote from the anchor. This is a departure from the ONS MDS Report No. OS-73.2 and from all referenced SRP editions in the proposed LAR which specify postulation of breaks at terminal ends, such as anchors where a break is most likely to occur due to the rigid 6-way constraint to the pipe provided by the anchor.

a) Evaluate the effect of the break at the anchor point/terminal end, as specified in the above discussion, provide an alternative method in lieu of this evaluation; or provide an acceptable justification as to why the alternative location selected is the most likely location for an HELB.

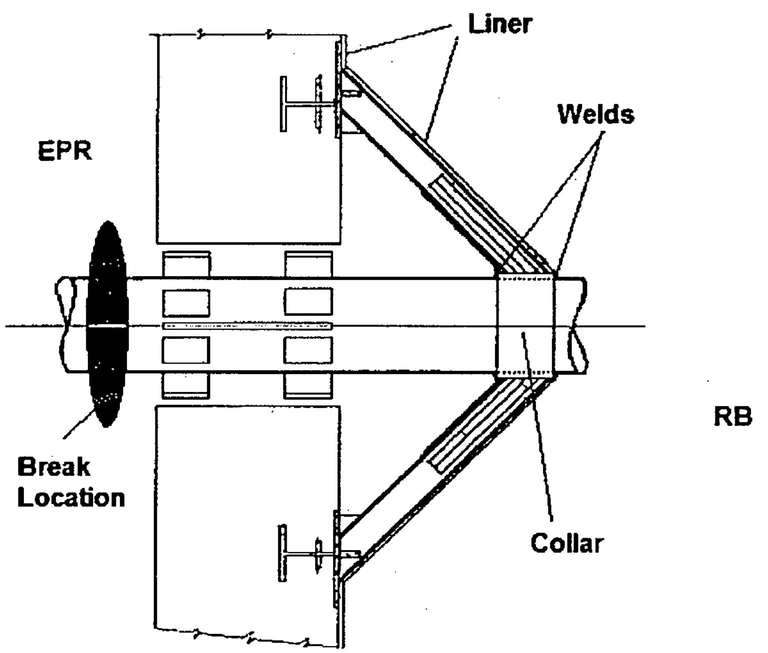
b) Please describe the consequences that the terminal end failure at the anchor point would have on containment integrity. Provide your findings and corresponding analyses that support your findings.

c) List all other HE piping where breaks were not postulated at the penetration anchors because the anchors were located inside containment and respond as in part "a" and "b" of this RAI.

Duke Response to RAI 10(a)

This issue was previously discussed during the March 5, 2007, meeting between the NRC and Duke and a common understanding reached (Ref. 5: Matrix item H8).

Figures 2.1.-1.a and 2.1.-1.b of MDS Report No. OS-73.2 clearly shows that the Main Steam Line break location is on the outside face (Auxiliary Building side) of the Reactor Building wall and not at the containment penetration anchor point. The figure also shows the anchor structure on the inside face of the wall away from the postulated break location. As noted in the response to RAI 9 above, the intent of the original MDS Report No. OS-73.2 was to address high energy line breaks occurring outside containment. Similarly the new report, ONDS-351, Rev. 2 seeks to evaluate the same.



Sketch RAI-10(a)

As shown in Sketch RAI-10(a), the Main Steam (MS) anchor structure is located inside the RB wall. Similar to the Main Feedwater rupture restraint, the MS anchor structure consists of eight structural sections that span between a welded collar on the pipe and the RB wall. At the RB wall those members are attached to embedments in the RB wall. Cover plates span the spaces between the structural members, providing a pressure boundary between the containment environment and the AB environment. The containment liner is welded directly to those cover plates. The collar is welded to the MS piping on both the inboard and outboard side of the collar. The design meets the criteria given in UFSAR Section 3.6.1.1(2):

2) *All penetrations are designed to withstand line rupture forces and moments generated by their own rupture as based on their respective design pressures and temperatures.*

A postulated rupture on the Auxiliary Building side of the structure would be similar to that postulated in the original MDS Report No. OS-73.2. A postulated rupture on the Reactor Building side of the structure would be similar to a MS break inside containment.

Duke Response to RAI 10(b):

There would be no affect on containment integrity should a break occur on either the upstream or downstream side of the structure. Refer to UFSAR Section 3.6.1.1(2) noted above.

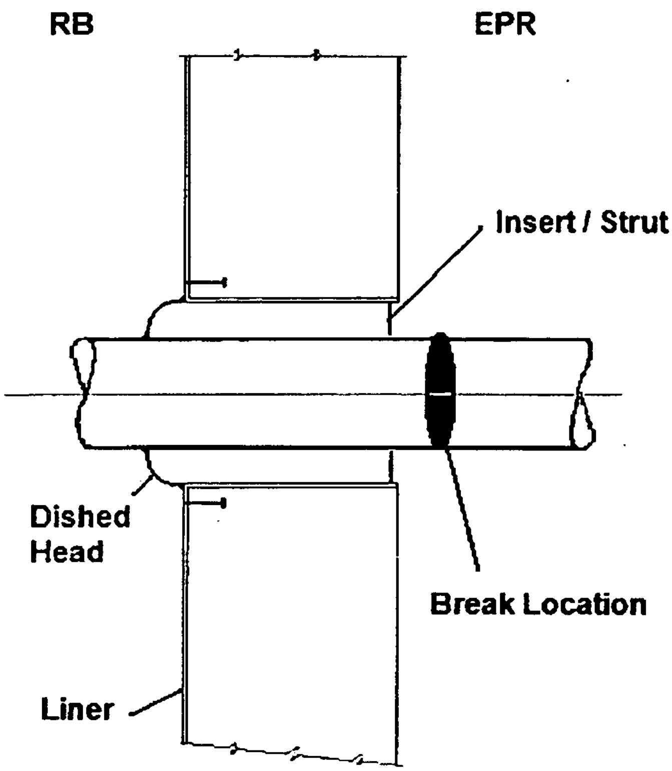
Duke Response to RAI 10(c):

There are three high energy systems that penetrate containment:

- Main Feedwater (MFDW) (2 penetrations per unit)
- Main Steam (MS) (2 penetrations per unit)
- High Pressure Injection (HPI) (6 penetrations per unit)

The Main Feedwater penetrations are addressed in the response to RAI 9 and the Main Steam penetrations are addressed in the responses to RAI -10a and 10b above. Regarding the HPI penetrations, each unit has one Letdown penetration (Penetration #6), one Normal Injection penetration (Penetration # 9), and four Reactor Coolant Pump Seal Injection penetrations (Penetrations 10A & B, and 23A & B) that are considered high energy. Penetrations 6, 9, 23A & B are located in the East Penetration Room of the AB. Penetration 10A & B are located in the West Penetration Room. Terminal end breaks were considered at each of these penetrations in the original MDS Report No. OS-73.2[5] as well as in the updated ONDS-351, Rev. 2 report. As shown in the Sketch RAI-10(c), the postulated breaks in the original MDS Report No. OS-73.2 were located on the AB side of the containment penetration. As noted before, these locations were previously approved by the AEC staff. The terminal end of the penetration is located at the welded connection of the dish head with the HPI piping. A failure of the piping at this location would be similar to an HPI break inside containment, albeit with a localized failure of containment.

[5] Breaks postulated at Penetration 6 is shown on Figure 2.1-15.a, Penetration 9 shown on Figure 2.1-14.b, Penetrations 10A & B on Figure 2.1-13.b2, and Penetrations 23A & B on Figure 2.1-13.b1 respectively in MDS Report No. OS-73.2.



Sketch RAI-10(c)

The RAI question, in general, illustrates conflicting criteria for the determination of the HELB design basis. Giambusso/Schwencer criteria 2(b) (1) notes that breaks should be postulated to occur at terminal ends. In addition, the Giambusso/Schwencer criterion 21 notes:

> *A description should be provided of the methods or analyses performed to demonstrate that there will be no adverse effects on the primary and/or secondary containment structures due to a pipe rupture outside these structures.*

Should a break be postulated at the penetration terminal end(s) as specified by Giambusso/Schwencer criterion 2(b)(1) for those nuclear plants with fixed penetrations, then it is apparent that in this situation, the Giambusso/Schwencer criterion 21 could not be met since such a break postulation would affect the containment liner.

It should also be noted that for all containment penetrations except the two MFDW penetrations, the penetration terminal end is actually located inside containment. Thus it is apparent that for these penetrations, Duke submitted postulated break locations outside containment, just inside the AB since the purpose of the criteria promulgated in Giambusso/Schwencer applied to postulated break location(s) outside containment.

RAI 11 (Section 1.3 - Calculations)

The LAR identifies various sections of the high energy piping that have been excluded due to normal operating temperature and pressure conditions. Please provide a copy of these calculations and justify the exclusions.

Duke Response to RAI 11

The exclusions and justifications for systems or portions of systems that are not normally in service were described in the response to RAI 3. Normal operating temperature and pressure in systems was based on operation at 100% rated power. A calculation OSC-8385, (ONDS-351, Rev. 2 Reference 10.2.1) was created to document these normal operating conditions. The method utilized to determine the normal operating conditions is provided in this response. The normal operating configuration at 100% rated power was established by reviewing the system operating procedures. Pressure and temperature instrumentation were selected where appropriate to define the conditions existing in the piping section of interest. Plant operating history was reviewed to determine a period of time when the units were operating at steady state of 100% rated power. Plant data was obtained from the operator aid computer (OAC) for the pressure and temperature instruments of interest during the selected operating period and documented in the attachments to the calculation. Average values were selected to define the normal operating conditions. The review of piping systems was limited to water and steam systems. Utilizing the data from OSC-8385, any systems or portions of systems, whose temperature exceeds 200°F, but operate at atmospheric pressure or below were excluded from damage assessments. The basis for the exclusion is that piping systems at or below atmospheric pressure possess insufficient energy to create pipe whips or jet impingement. This exclusion principle was applied to the "E" Extraction Steam piping and the Steam Seal Header return piping.

Duke plans to provide a copy of this calculation on a SharePoint access system for NRC review. The establishment of a SharePoint system for the Oconee HELB and Tornado LARs is currently ongoing.

RAI 12 (Section 1.5 - Definitions)

Page 1-10 of the LAR states that, "The Initial Operating Conditions are the conditions, upon which the high energy lines & their boundaries are identified." The definition of "Initial Operating Conditions (or "Normal Operating Conditions")" stated in this section is:

> "These conditions are the physical parameters that would exist within an ONS Unit with the Unit operating at 100% rated thermal power level (full power)."

This definition is inconsistent with the definition given in reference 10.1.3 (BTP ASB 3-1), which defines Normal Plant Conditions as plant operating conditions during reactor startup, operation at power, hot standby, or reactor cool-down to cold shutdown condition.

a) Please provide a basis for the use of a definition different than that in the SRP.

b) This RAI also ties to the LAR definition of HE line. Therefore, please delineate which specific fluid systems were eliminated from HELB considerations due to this alternate definition.

Duke Response to RAI 12(a)

"Normal Plant Conditions" was defined on page 1-15 of ONDS-351, Rev. 2. The definition is consistent with the definition provided in BTP ASB 3-1. This definition was used to identify systems and portions of systems that may be exposed to high energy conditions during operation in modes 1 through 4. However, in analyzing potential ruptures in high energy lines for plant response and the establishment of safe shutdown, the initial operating conditions are assumed to be 100% rated thermal power. Hence, a new term of "Initial Operating Conditions" was established to clarify when high energy line breaks occur. "Initial Operating Conditions" is defined on page 1-14 of ONDS-351, Rev. 2. This term is consistent with the analysis presented in section 3.0 of the MDS Report OS-73.2. As discussed in RAI 3, certain systems were excluded based on their short operating period at high energy conditions.

Duke Response to RAI 12(b)

Refer to Duke's response to RAI 3 for specific systems that were eliminated from HELB considerations.

<u>RAI 13</u> (Section 1.5 - Definitions)

On page 1-11, the definition of "Normal Plant Conditions" notes that the definition is used to exclude certain piping sections from the requirement of postulating HELBs on these sections. Please explain how this definition was used to exclude certain piping sections, and provide a list of all those sections of piping where this definition was used to exclude them from postulating HELBs.

Duke Response to RAI 13

"Normal Plant Conditions" is used to identify systems and portions of systems that could be operated in Modes 1 through 4, and subjected to high energy conditions. Those systems that could be operated at high energy conditions for short periods of time during modes 1 through 4 were excluded. Breaks have been postulated in high energy systems with the unit operating at 100% of rated power. As such the analysis was performed with the plant configuration existing at 100% of rated power. Systems and portions of systems being excluded are described in Duke's response to RAI 3.

RAI 14

In the last sentence of page 8-22 of Enclosure 3, it states that, "The (Main) Feedwater System high energy piping is seismically analyzed from the inlet valves 1FDW-26 & 1FDW-21, of the "A" HP Feedwater Heaters to the Containment Penetrations. The seismically analyzed portions of the FDW piping are Duke piping Class "G" from these valves to the Feedwater valves 1FDW-41 & 1FDW-42 and 1FDW-32 & 1FDW-33." According to UFSAR Table 3-1, Piping Class "G" was <u>not</u> designed for seismic loading. Please reconcile the apparent discrepancy between the FSAR table and the above statements in ONDS-351, Rev. 2.

Duke Response to RAI 14

The subject piping, while not classified as Class F, is nevertheless seismically designed, analyzed, and supported as part of the overlap/boundary conditions to assure that the Class G/F boundary is seismically protected. Thus the stresses are considered accurate for use in the determination of intermediate break locations.

RAI 15

Provide a list of all the equipment types (such as manufacturer, model number, etc.) that need to be qualified for the environmental conditions of this LAR. Identify any new components added to the equipment qualification (EQ) program. Identify any existing components that were replaced due to the LAR. Confirm that all components identified above are qualified in accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Section 50.49.

Duke Response to RAI 15

As discussed on pages 8-31 of the HELB Report (ONDS-351, Rev. 2), the only areas of the station where environmental qualification was considered due to a harsh environment following a postulated HELB outside containment, are the East Penetration room (EPR) and the West Penetration room (WPR). The breaks of concern are the Main Steam line and the Main Feedwater lines in the EPR. This was also the case addressed in the original MDS Report No. OS-73.2. Environmental profiles were recalculated for these postulated breaks. These revised profiles are documented in calculation OSC-8104 (ONDS-351, Rev. 2, Reference 10.2.3). The following components were evaluated for the new environmental profiles inside the EPR & WPR. This list is documented in calculation OSC-6182 (ONDS-351, Rev. 2, Reference 10.2.5).

(Note: A prefix of 'x' in the equipment ID signifies applicability for all three units):

Equipment ID	Equipment Type	Manufacturer/Model Number
xBS VA0001	Motor-operated valve	Limitorque
xBS VA0002	Motor-operated valve	Limitorque
xFDWVA0103	Motor-operated valve	Limitorque
xFDWVA0104	Motor-operated valve	Limitorque
xFDWIP0315	Signal Converter	Fisher 546NS

Equipment ID	Equipment Type	Manufacturer/Model Number
xFDWIP0316	Signal Converter	Fisher 546NS
xGWDSV0003	Solenoid Valve	ASCO NP206
xHPISV0090	Solenoid Valve	ASCO NP8316
xHPISV0095	Solenoid Valve	ASCO NP8321
xHP VA0026	Motor-operated Valve	Limitorque
xHP VA0027	Motor-operated Valve	Limitorque
xHP VA0409	Motor-operated Valve	Limitorque
xHP VA0410	Motor-operated Valve	Limitorque
xHPIFT0159	Flow Transmitter	Rosemount 1154
xHPIFT0160	Flow Transmitter	Rosemount 1154
1LP VA0003	Motor-operated Valve	Limitorque
xLP VA0017	Motor-operated Valve	Rotork
xLP VA0018	Motor-operated Valve	Rotork
xLPIFT0004P	Flow Transmitter	Rosemount 1153B
xLPIFT0005P	Flow Transmitter	Rosemount 1153B
xLPITE0209	Thermocouple	Conax 7S22
3LPITE0210	Thermocouple	Conax 7S22
xLPSPT0010	Pressure Transmitter	Rosemount 1154
xLPSPT0011	Pressure Transmitter	Rosemount 1154
xLPSPT0012	Pressure Transmitter	Rosemount 1154
xLPSPT0013	Pressure Transmitter	Rosemount 1154
xLPSSV1054	Solenoid Valve	Valcor V70900-65
xLPSSV1055	Solenoid Valve	Valcor V70900-65
xLPSSV1061	Solenoid Valve	Valcor V70900-65
xLPSSV1062	Solenoid Valve	Valcor V70900-65
xLPSVA0016	Motor-operated Valve	Limitorque
xLPSVA0018	Motor-operated Valve	Limitorque
xLPSVA0019	Motor-operated Valve	Limitorque
xLPSVA0021	Motor-operated Valve	Limitorque
xLPSVA0022	Motor-operated Valve	Limitorque
xLPSVA0024	Motor-operated Valve	Limitorque
xPR SV0075	Solenoid Valve	ASCO NP8316
xPR SV0076	Solenoid Valve	ASCO NP8316
xRC PS0453	Pressure Switch	Barton 581
xRC PS0454	Pressure Switch	Barton 581
xRC PS0455	Pressure Switch	Barton 581
xRC PS0456	Pressure Switch	Barton 581
xRC PS0457	Pressure Switch	Barton 581
xRC PS0458	Pressure Switch	Barton 581
xRC SV0036	Solenoid Valve	Valcor V70900-65
	Electrical Penetration Assemblies	Conax

Equipment ID	Equipment Type	Manufacturer/Model Number
	Electrical Penetration Assemblies	D.G. Obrien
	Electrical Penetration Assemblies	Viking
	States Terminal Blocks	
	Cabling	

All of the above components existed prior to the LAR. None of these components needed to be added to the Equipment Qualification program as a result of the LAR. All PSW System components will be qualified for the applicable environment. None of the above listed components were replaced as a result of the LAR. The temperature and pressure profile for components located inside the EPR & WPR was changed as a result of new analysis for the postulated breaks on the Main Steam piping and Main Feedwater piping located inside the East Penetration Room. The above components were reviewed for the new pressure and temperature profiles and found to be qualified. The component evaluations are documented in calculation OSC-8505 (ONDS-351, Rev. 2, Ref. 10.2.17).

RAI 16

Provide the environmental profiles and demonstrate that the environmental conditions of this LAR are enveloped by the existing EQ profiles or demonstrate qualification of the components to the environmental conditions of this LAR.

Duke Response to RAI 16

High Energy Line Breaks (HELBs) are postulated in the Turbine Building and in the Auxiliary Building. Within the Turbine Building any electrical equipment, potentially affected by the environmental conditions generated by postulated HELBs, are also targets of the direct effects (i.e.: pipe whip and jet impingement) of the HELBs. As such, the qualification of this electrical equipment is not necessary, because the direct interactions require an alternate methodology for achieving and maintaining a Safe Shutdown condition. This alternate methodology, which does not rely on any equipment in the Turbine Building, would be utilized, if the electrical equipment in the Turbine Building failed as a result of adverse environmental conditions. A general discussion of this strategy is provided in Section 3.1 of the HELB Report (ONDS-351, Rev. 2), and specific Shutdown Sequences are delineated in the interaction analyses provided in Sections 4.0 – 6.0 of the HELB Report.

Within the Auxiliary Building equipment qualification of Shutdown Components would only be required for postulated Main Feedwater and Main Steam HELBs in the East Penetration Room (EPR). Shutdown Components in both the East and West Penetration Rooms that are required for the mitigation of these postulated Main Feedwater and Main Steam line HELBs are qualified, and no components have been added or deleted from the ONS Equipment Qualification (EQ) Program. However, the temperature and pressure profiles inside of the East and West Penetration Rooms have been revised for these postulated HELBs on the Main Feedwater and

Main Steam piping in the East Penetration Room. The equipment (listed in RAI 15) was evaluated against the revised temperature and pressure profiles and found to be qualified. This qualification is documented in calculation OSC-8505 (ONDS-351, Rev. 2, Reference 10.2.17), the revised profiles are documented in calculation OSC-8104 (ONDS-351, Rev. 2, Reference 10.2.3), and a description of these calculations and their contents are provided in Section 1.3.4 of the HELB Report.

For postulated HELBs in other areas of the Auxiliary Building, equipment qualification is not required. Either the loss of any Shutdown Components in these areas would not preclude achieving and maintaining a Safe Shutdown condition, or adverse environmental conditions are not generated. Aside from the Main Steam and Main Feedwater systems, there are two (2) additional systems with postulated HELBs inside the Auxiliary Building. These systems are the High Pressure Injection (HPI) System and the Plant Heating (PH) System. The HPI System has HELBs postulated in the East Penetration Room, the West Penetration Room, and the HPI Pump Room of each unit. The postulated HPI HELBs in these rooms may create a flooding hazard, but no adverse temperature and pressure environments are generated due to the low temperature (< 110°F) of the Borated Water Storage Tank and/or the Letdown Storage Tank water. The postulated HELBs on the PH System are located in various areas of the Auxiliary Building, including the Ventilation Equipment Rooms (505, 520, & 565) and Storage Room 408B. The evaluation of these postulated HELBs in the Ventilation Equipment Rooms and the Storage Room 408B are documented in Calculations OSC-9603, OSC-9554, OSC-9656, & OSC-9693 (ONDS-351, Rev. 2, References 10.2.50, 10.2.51, 10.2.61, & 10.2.62, respectively). These evaluations show that no revisions to the ONS EQ Program are required. The postulated PH System HELBs in the other areas of the Auxiliary Building do not adversely affect Shutdown Components and do not require any changes to the station configuration. The interaction analyses for postulated HELBs in the Auxiliary Building are provided in Sections 4.2.1 (Unit 1), 5.2.1 (Unit 2), and 6.2.1 (Unit 3) of the HELB Report.

RAI 17

In section 9 of the LAR, the licensee stated that the 125 VDC cable will be rerouted or will be protected from the postulated HELBs. If this cable is not rerouted, then please explain how it will be protected from the postulated HELBs.

Duke Response to RAI 17

The primary and backup cables associated with the 125 vdc vital I&C system will be rerouted out of the Turbine Building to eliminate vulnerabilities to HELB and/or Tornado events.

RAI 18

In section 9 of the LAR, the licensee stated that the weep holes will be installed in Viking Electrical Penetration Enclosures. The licensee also stated that these weep holes will prevent the buildup of water within the enclosures. The NRC staff requests the licensee to confirm that 1) an appropriate drainage is provided for all junction boxes which contain components that are required to mitigate the environmental conditions of this LAR, and 2) the weep holes of these junction boxes will be inspected for blockage at appropriate intervals.

Duke Response to RAI 18

1) Duke has agreed to install weep holes in the outside containment enclosures for the Viking Electrical Penetrations. These weep holes are considered an enhancement to the enclosures and do not change the existing environmental qualification of the Viking Electrical Penetrations. All other equipment required to mitigate the environmental conditions of this LAR has been previously environmentally qualified and any existing design features such as sealing, weep holes, etc. will be maintained.

2) Duke will periodically inspect the new weep holes installed on the outside containment junction boxes for the Viking Electrical Penetrations for blockage and take appropriate corrective action as necessary to ensure the weep holes are free from debris.

RAI 19

The NRC staff requests the licensee to confirm that failure of a non-safety related component would not adversely affect the safety function of a safety related component under postulated environmental conditions.

Duke Response to RAI 19

As a result of postulated HELBs outside of the containment, two (2) compartments within the Auxiliary Building were identified, where qualification of equipment is required. These compartments are the East Penetration Room (EPR) and the West Penetration Room (WPR). For postulated HELBs in the EPR, a list of components in the EPR and WPR requiring equipment qualification has been generated, so that sufficient equipment is available to mitigate the consequences of these postulated HELBs. This list is documented in calculation OSC-6182 (ONDS-351, Rev. 2, Reference 10.2.5). This list of components has been generated based upon the existing station configuration.

None of these existing components needed to be added to the Equipment Qualification (EQ) Program at the ONS. However, because of revised temperature and pressure profiles, resulting from postulated Main Feedwater or Main Steam line HELBs in the EPR, additional equipment qualification evaluations of these components was conducted. The revised temperature and pressure profiles are documented in calculation OSC-8104 (ONDS-351, Rev. 2, Reference 10.2.3), and the component evaluations are documented in calculation OSC-8505 (ONDS-351, Rev. 2, Reference 10.2.17). Since no existing components were added to the ONS Equipment Qualification Program as a result of the proposed LAR, no new unacceptable EQ interactions could have been generated. Moreover, all components located in the EPR and WPR, needed to mitigate these postulated HELBs in the EPR, have been demonstrated to meet the required EQ profiles and have been evaluated as being available to support the post HELB Shutdown Sequence. Hence, no safety functions of these components would be lost due to environmental consequences in the EPR and WPR. The interaction analyses for these HELBs are documented in ONDS-351, Rev. 2, Sections 4.2.1.1.2 (Unit 1), 5.2.1.1.2 (Unit 2), and 6.2.1.1.2 (Unit 3).

RAI 20

The NRC staff requests the licensee to identify if any components are exposed to direct jet impingement due to main feed water HELBs and confirm that these components are qualified to survive the HELB.

Duke Response to RAI 20

The Main Feedwater lines are routed from the Turbine Building through the Auxiliary Building to the Containment Penetrations. HELBs are postulated on the Main Feedwater lines in both buildings. In the Auxiliary Building the Main Feedwater line HELBs are only postulated in the East Penetration Room (EPR) of each unit. Sections 4.1.4 (Unit 1), 5.1.4 (Unit 2) and 6.1.4 (Unit 3) of the HELB Report (ONDS-351, Rev. 2) and Tables 4.1.4, 5.1.4, and 6.1.4 of the HELB Report identify the locations of the postulated Main Feedwater line HELBs in the Turbine Building and in the EPR of the Auxiliary Building in Units 1, 2, & 3 respectively.

Within the Turbine Building, many components identified as Shutdown Components, are exposed to the jet impingements from postulated Main Feedwater line HELBs. However, for these postulated Main Feedwater line HELBs, no credit is taken for event mitigation for these impacted Shutdown Components. Therefore, these components are not required to survive these postulated HELBs and are not required to be qualified. Moreover, the interaction analysis in the HELB Report also documents that no Shutdown Components within the Auxiliary Building are directly or indirectly impacted by these postulated HELBs in the Turbine Building. The Shutdown Components impacted by these postulated HELBs in the Turbine Building are documented in Calculations OSC-7516.02 (Unit1), OSC-7517.02 (Unit 2), and OSC-7518.02 (Unit 3) and summarized in Tables 4.2.4 (Unit 1), 5.2.4 (Unit 2), and 6.2.4 (Unit 3) of the ONS HELB Report (ONDS-351, Rev. 2). The interaction analysis for the postulated Main Feedwater line HELBs in the Turbine Building are provided in Sections 4.2.2.4 (Unit 1), 5.2.2.4 (Unit 2), and 6.2.2.4 (Unit 3) of the HELB Report (ONDS-351, Rev. 2).

Within the EPR of each unit in the Auxiliary Building there are postulated breaks and critical cracks on the Main Feedwater lines. The interaction analyses for these HELBs are documented in ONDS-351, Rev. 2, Sections 4.2.1.1.2 (Unit 1), 5.2.1.1.2 (Unit 2), and 6.2.1.1.2 (Unit 3). The components impacted by direct jet impingement are identified in these sections and the above listed tables. The interaction analysis assumed that these components are lost and fail in the most undesired state, consistent with the evaluation criteria established in Section 2.4 of ONDS-

351, Rev. 2. For all of the postulated Main Feedwater HELBs in the EPR of the Auxiliary Building and for the identified adverse direct jet interactions, a pathway for achieving and maintaining a Safe Shutdown condition is documented. Therefore, it is not necessary to qualify any of the directly impacted Shutdown Components in the Auxiliary Building due to the postulated Main Feedwater line HELB jet impingements.

In summary, it is not necessary to qualify any Shutdown Components directly impacted by Main Feedwater HELB jet impingements within the Turbine Building or the Auxiliary Building, because the interaction analysis takes no credit for these components as delineated in the respective sections of ONDS-351, Rev. 2.

RAI 21

In section 3.8 of ONDS-351, Rev. 2, Page 3-17, the licensee stated that the protect service water system provided power to the systems and components such as high pressure injection makeup to the reactor coolant system (RCS) from the borated water storage tank, reactor coolant pump seal injection flow control, reactor vessel head vent valves, RCS high point vent valves, pressurizer heaters and vital instrumentation and control battery chargers.

The NRC staff requests the licensee to provide qualification basis for these components, if these components are affected by the postulated HELBs.

Duke Response to RAI 21

On Page 3-2 of ONDS-351, Rev. 2, the design basis for the Protected Service Water (PSW) System is stated as "...a standby system for use under emergency conditions, where plant systems in the Turbine Building are lost..." For those postulated HELBs in the Turbine Building requiring the PSW System, any component powered and/or operated by the PSW System, is unaffected by these HELBs, as required by the design basis of the PSW System. This includes the Shutdown Components, their support systems, cables, and alternate power switches.

With the two exceptions discussed in the next paragraph, the components capable of being powered and/or controlled by the PSW System are not adversely affected by postulated HELBs in the Auxiliary Building. These two exceptions are as follows:

- Pressurizer Heater power supplies in the EPR
- (PSW) Pressurizer Heater Power Transfer Switches

The postulated HELBs in the Auxiliary Building do not directly or indirectly impact any of the remaining components or their support systems. Cables for these components that are routed through the East or West Penetration Rooms are qualified for the adverse environmental conditions in these rooms, created by these postulated Main Feedwater or Main Steam line HELBs. The qualification of the cables is documented in calculation OSC-8505 (ONDS-351, Rev. 2, Ref. 10.2.17).

It should be noted that postulated Main Feedwater line or Main Steam line HELBs in the East Penetration Rooms (EPR) may cause a loss of all pressurizer heaters with the exception of Bank 2, Groups B & C heaters. However, the pressurizer heaters are not required during the Shutdown Sequence for these postulated HELBs. Therefore, the pressurizer heater power supplies and the associated power transfer switches do not need to be qualified to the environmental profiles resulting from a postulated rupture in the Main Steam or Main Feedwater lines located in the EPR. There are also postulated HELBs on the HPI Pump discharge lines in the HPI Pump Room, the East Penetration Room, and the West Penetration Room in each ONS unit. However, the direct and indirect interactions caused by these postulated HPI HELBs, do not result in loss of the HPI System, the capability of the HPI pumps to take suction from the Borated Water Storage Tank, or cause a loss of RCP seal injection cooling. The HPI System interaction analyses are documented in Sections 4.2.1.1.1, 4.2.1.2.1, & 4.2.1.3 (Unit 1); 5.2.1.1.1, 5.2.1.2.1, & 5.2.1.3 (Unit 2); & 6.2.1.1.1, 6.2.1.2.1, & 6.2.1.3 (Unit 3) of the HELB Report (ONDS-351, Rev. 2).

In summary, equipment qualification of the existing components, their support systems, and power supplies, relative to the operation of the PSW System, are not required because they are not affected by these postulated HELBs or are not required for these postulated HELBs. Cables for these components routed through the East or West Penetration Rooms are qualified for the postulated Main Feedwater line and Main Steam line HELBs in the EPR, and the qualification is documented in Calculation OSC-8505.

Tab 2

Duke Energy RAI response dated 12-7-2010

Duke Energy®

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December 7, 2010

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

Subject: Duke Energy Carolinas, LLC
Oconee Nuclear Station, Units 1, 2, and 3
Docket Numbers 50-269, 50-270, and 50-287,
Renewed Operating Licenses DPR-38, DPR-47, and DPR-55
High Energy Line Break License Amendment Request - Response to Request for Additional Information

References:

1. Letter to the U. S. Nuclear Regulatory Commission from David Baxter, Vice President, Oconee Nuclear Station, Duke Energy Carolinas, LLC, "Proposed License Amendment Request to Revise the Oconee Nuclear Station Current Licensing Basis for HELB events outside of the Containment Buildings; License Amendment Request No. 2008-005," dated June 26, 2008.
2. Letter to the U. S. Nuclear Regulatory Commission from Dave Baxter, Vice President, Oconee Nuclear Station, Duke Energy Carolinas, LLC, "Proposed License Amendment Request to Revise the Oconee Nuclear Station Current Licensing Basis for HELB Events outside of the Containment Building - Unit 2; License Amendment Request No. 2008-006," dated December 22, 2008.
3. Letter to the U. S. Nuclear Regulatory Commission from Dave Baxter, Vice President, Oconee Nuclear Station, Duke Energy Carolinas, LLC, "Proposed License Amendment Request to Revise the Oconee Nuclear Station Current Licensing Basis for High Energy Line Break Events Outside of the Containment Building," License Amendment Request No. 2008-007, dated June 29, 2009.
4. Letter from John Stang, Senior Project Manager, Office of Nuclear Reactor Regulation, Nuclear Regulatory Commission to Dave Baxter (Duke), "Request for Additional Information (RAI) Regarding the Licensee Amendment Requests (LARs) for High Energy Line Break Mitigation," dated October 8, 2010.
5. Letter from Dave Baxter, Site Vice President, Oconee Nuclear Station, Duke Energy Carolinas, LLC, to the U. S. Nuclear Regulatory Commission, "Tornado Mitigation License Amendment Request - Response to Request for Additional Information," dated August 31, 2010.
6. Letter from Dave Baxter, Site Vice President, Oconee Nuclear Station, Duke Energy Carolinas, LLC, to the U. S. Nuclear Regulatory Commission, "Tornado Mitigation License Amendment Request - Response to Request for Additional Information," dated June 24, 2010:

7. Letter from Dave Baxter, Site Vice President, Oconee Nuclear Station, Duke Energy Carolinas, LLC, to the U. S. Nuclear Regulatory Commission, "License Amendment Request to Revise Portions of the Updated Final Safety Analysis Report Related to the Tornado Licensing Basis," dated June 26, 2008.

By letters dated June 26, 2008, December 22, 2008, and June 29, 2009, Duke Energy Carolinas, LLC (Duke Energy) submitted three (3) license amendments that comprise the final License Amendment Request (LAR) for High Energy Line Break (HELB) events outside of containment (Refs: 1, 2, and 3). This LAR revises the current licensing basis regarding HELB mitigation for the Oconee Nuclear Station (ONS).

Duke Energy received a Request for Additional Information (RAI) related to this LAR on July 24, 2009, and provided a response on October 23, 2009. Duke Energy received an additional RAI on October 8, 2010 (Ref. 4). This submittal responds to this RAI.

The engineering design for questions associated with RAI questions 25, 42, 43, 44, 45, 46, 47, 48, 49, 50, 51 and 52 is subject to revision to support field conditions and as-built configuration. The information contained in the Enclosure and provided on the SharePoint represents the latest information available as of the date of this letter. Also, upon acceptance of the RAI responses, the Oconee HELB Report (ONDS-351) will be revised to include the information in the RAI responses. This action will be tracked within Oconee's corrective action program.

If you have any questions in regard to this letter, please contact Stephen C. Newman, Regulatory Compliance Lead Engineer, Oconee Nuclear Station, at (864) 873-4388.

I declare under penalty of perjury that the foregoing is true and correct. Executed on December 7, 2010.

Sincerely,

TPGillespie

T. Preston Gillespie, Jr.
Vice President
Oconee Nuclear Station

Enclosure
Attachment

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Enclosure

Response to Request for Additional Information

RAI 1 [H]

The description provided in Section 7.3 of the LARs, letdown line break, does not provide the NRC staff with sufficient information necessary to perform an independent dose consequence calculation. To ensure a complete and accurate safety assessment of the proposed LAR, the NRC staff needs to assess the safety significance of all of the changes to the current licensing basis (CLB) parameters used in the letdown line break dose consequence analysis.

Provide additional information describing all of the basic parameters used in the letdown line break off-site and control room dose consequence analyses. For each parameter, please indicate the CLB value, the revised value where applicable, as well as the basis for any changes to the CLB values. Please provide additional information describing all of the basic parameters used for the letdown line break off-site and control room dose consequence analyses. For each parameter, please indicate the CLB value, the revised value where applicable, as well as the basis for any changes to the CLB values.

Duke Energy Response

Letdown line breaks are not classified as a design basis event in the current licensing basis (CLB). The analysis for postulated line breaks in the letdown line is not contained in the current Chapter 15 of the Updated Final Safety Analysis Report (UFSAR). Breaks were postulated in the letdown line based on the high energy line break (HELB) rules established in a letter from the Atomic Energy Commission (AEC) dated 12/12/1972. A terminal end break was postulated at the containment penetration (between the reactor building wall and the outboard containment isolation valve). Other breaks were also postulated in the high energy portion of the piping downstream of the outboard containment valve and upstream of the pressure reducing devices. An operational analysis was performed for these postulated breaks and documented in MDS Report No. OS-73.2, "Analysis of Effects Resulting from Postulated Piping Breaks Outside Containment for Oconee Nuclear Station - Units 1, 2, and 3," dated 4/25/1973.

The analysis contained in the MDS report established the licensing basis for the postulated HELBs in the letdown line. One analysis was provided to address all of the postulated breaks in the letdown line. The analysis assumed a complete severance of the 2-1/2 inch letdown line. No operator action was assumed. Reactor coolant was assumed to flow out the break until the isolation valves were automatically closed. It should be understood that a failure of the containment inboard isolation valve was not postulated for this event since one of the postulated break locations was at the penetration upstream of the containment outboard isolation valve. The normal makeup system was assumed to function to delay the time in which the valves would receive an automatic signal to close. Engineered Safeguards (ES) was assumed to actuate by low reactor coolant pressure at 1500 psig. Analysis showed that the letdown pathway would be isolated at approximately 160 seconds after the break. Off-site releases were considered to be within acceptable limits for this accident. The parameters used to determine that off-site doses were within acceptable limits were not provided for the CLB.

Section 7.3 reflects the analysis that was performed to address changes to the HELB selection and mitigation of postulated pipe breaks in the letdown line. Line breaks in the high energy portion of the letdown line downstream of the containment outboard isolation valve were eliminated based on the piping stress analysis. The previously postulated line break upstream of the containment outboard isolation valve (at the reactor building penetration) remains as the only postulated HELB in the letdown line outside containment. A single active failure of a containment inboard isolation valve (xHP-3 or xHP-4) to close following an ES signal is being considered in the new analysis. Off-site doses as well as control room doses were calculated to determine the required time for operator response to mitigate a single active failure to the containment inboard isolation valve and remain within acceptable limits. The acceptable limits that have been imposed are based on Standard Review Plan (SRP) 15.6.2 and Regulatory Guide 1.183.

The basic parameters used in the off-site and control room dose consequence analyses contained in Section 7.3 are:

- The mass and energy release from the letdown break as used in the dose analysis is described in response to question 3.
- The initial fission product concentrations in the reactor coolant are assumed to be at the maximum equilibrium values as permitted by plant technical specifications.
- An additional iodine spike is assumed to occur. The spike is modeled by increasing the equilibrium fission product activity release rate from the fuel by a factor of 500.
- The fraction of iodine assumed to become airborne and released to the environment is equal to the fraction of the reactor coolant flashing into steam in the depressurization process, and the mass of coolant that is already in the vapor phase. The total flash fraction used for the duration of the accident is calculated to be 31.4%, based on a constant enthalpy process.
- The iodine released from the letdown line break is assumed to be 97% elemental and 3% organic.
- All of the noble gas radionuclides released from the letdown line break are assumed to be released to the environment.
- The atmospheric dispersion factor (X/Q) for the exclusion area boundary (EAB) for the 0-2 hour period is assumed to be 2.2E-4 sec/m^3. X/Q values for the outer boundary of the low population zone (LPZ) off-site dose calculations are:

Time Period	LPZ X/Q (sec/m^3)
0 - 8 hours	2.35E-5
8 - 24 hours	4.70E-6
1 - 4 days	1.50E-6
4 - 30 days	3.30E-7

- RG-1.183 breathing rate values are used in determining off-site dose predictions.
- It is assumed that the Control Room operators will start the CRVS Booster Fans within 30 minutes of ES actuation, which occurs about 6 minutes post-accident.
- The control room booster fan intake flow rate is assumed to be 1215 cfm.
- The Unit 1 and 2 Control room was modeled in the analysis. The analysis used a free volume of 86,447 cubic feet for this control room.
- The unfiltered in-leakage into Units 1 and 2 Control room (which is more limiting than Unit 3) is assumed to be 1202 cfm until the outside air booster fan is started by the operator. After the booster fan is started, the in-leakage is assumed to be 0 cfm, which is conservative for this accident scenario. Due to the short break flow duration and large amount of unfiltered in-leakage that has already contaminated the CR during the unpresssurized time period, once the CR is pressurized, dose actually decreases with increased unfiltered in-leakage (and corresponding increased exhaust flow rate).
- The filter efficiencies for the control room intake iodine filters are assumed to be 99% for particulate, 95% for organic, and 99% for elemental iodine.
- There are two air intakes for the control room outside air booster fans. One intake is assumed to supply 55% of the air flow while the other is assumed to supply 45% of the air flow. Only the air intake with the higher flow is assumed to be located within the wind direction window as defined in RG-1.194 from the postulated release point.

- The X/Q values (adjusted for the 55 / 45 airflow split) used for the Control Room are:

Time Period	X/Q (sec/m^3)
0 - 2 hours	9.85E-4
2 - 8 hours	6.88E-4
8 - 24 hours	3.00E-4
24 - 96 hours	2.29E-4
96 - 720 hours	1.84E-4

  Note: The 0-2 hour X/Q is used during the period of maximum activity release as determined by LOCADOSE. The 2-8 hour X/Q is used during the rest of the first 8 hours.

- RG-1.183 is utilized in determining occupancy factors and breathing rate for the control room operators.
- Dose Conversion Factors are based on the Federal Guidance Reports 11 and 12.

RAI 2 [H]

The analysis provided in Section 7.3 of the HELB report in the Unit 3 LAR, for the letdown line break, assumes a double-ended guillotine break of the 2.5-inch letdown line. Please provide additional information describing the basis for the selection of this line to ensure that the most severe radioactive releases have been considered.

Duke Energy Response

Break selection is based on the high energy line break rules. The letdown line break being analyzed is a terminal end line break outside containment between the inboard and outboard containment isolation valves. Pipe stresses were evaluated in the remaining high energy portion of the letdown line. No other locations on the high energy portion of the letdown line were found to meet the break threshold.

RAI 3 [H]

Provide additional information describing the calculated mass flow rate out of the break as well as the total quantity released as used in the dose analysis.

Duke Energy Response

A thermal-hydraulic analysis was performed using the RETRAN-3D computer code to determine the plant response as well as the break flow rate. Piping losses in the letdown piping inside the Reactor Building were considered in the analysis for the break flow rate. The letdown piping resistances inside containment were evaluated for all three units. Unit 1 had the lowest piping resistance of all three units and hence the highest break flow. Using the lowest piping resistance, the initial break flow rate was calculated to be approximately 102 lbm/sec. The break flow rate decreased to a minimum value of approximately 69 lbm/sec when the RCS pressure decreased to the point where ES actuated at approximately 6 minutes. Break flow rate then began to increase until RCS pressure stabilized. The break flow rate then remained relatively constant at approximately 90 lbm/sec until isolated by the operators.

The RETRAN analysis did not identify when operator actions would be taken to isolate the break. Therefore the break flow analysis was extended out in time to approximately 4000 seconds. The dose analysis assumed operator action would be taken to isolate the break within 20 minutes following ES actuation. The break flow rate used in the dose analysis was assumed to continue for approximately 26 minutes. The total quantity released during the 26 minutes of break flow was calculated to be approximately 140,000 lbm. No leakage was assumed through the closed isolation valve in the analysis. It was also assumed that no cooling of the reactor coolant through the letdown cooler and no ambient heat loss occurred through the piping from the RCS to the break location inside the East Penetration Room to maximize the flashing fraction. Time intervals were established to simplify the inputs into the dose analysis. The maximum break flow rate and the minimum RCS mass over the established time intervals used in the dose analysis is provided in the table below.

Letdown Line Break Flow Rate(lbm/min)	RCS Mass (lbm)	Time Interval(hours)
6170	500904	0.000 to 0.006
6107	499248	0.006 to 0.011
6058	497609	0.011 to 0.017
6010	495985	0.017 to 0.022
5964	494376	0.022 to 0.028
5918	492782	0.028 to 0.033
5876	491202	0.033 to 0.039
5832	489637	0.039 to 0.044
5788	488087	0.044 to 0.050
5766	486558	0.050 to 0.056
5693	485199	0.056 to 0.061
5066	483901	0.061 to 0.067
4955	482635	0.067 to 0.072
4890	481390	0.072 to 0.078
4844	480163	0.078 to 0.083
4758	478956	0.083 to 0.089
4705	478024	0.089 to 0.094
4428	478024	0.094 to 0.100
4288	479930	0.100 to 0.106
4377	481765	0.106 to 0.111
4467	483532	0.111 to 0.117
4557	485229	0.117 to 0.122
4640	486854	0.122 to 0.128
4724	488405	0.128 to 0.133
4810	489885	0.133 to 0.139
5001	491294	0.139 to 0.153
5180	494510	0.153 to 0.167

5332	497309	0.167 to 0.181
5457	499709	0.181 to 0.194
5540	501743	0.194 to 0.208
5526	503485	0.208 to 0.222
5545	505312	0.222 to 0.250
5552	508856	0.250 to 0.278
5550	512356	0.278 to 0.434

RAI 4 [H]

Provide additional information describing the initial fission product concentrations in the reactor coolant system (RCS) and the basis for their selection as the maximum equilibrium values permitted by the technical specifications (TSs).

Duke Energy Response

Departure from nucleate boiling (DNB) fuel failures are not postulated for the letdown line break. SRP 15.6.2 states that the initial fission product concentrations in the primary coolant are assumed to be at maximum equilibrium values permitted by technical specifications. Oconee's technical specification limits on RCS activity are, Dose Equivalent Iodine-131(DEI-131) is less than or equal to 1.0 μCi/gm, and gross specific activity is less than or equal to 100/Ē μCi/gm. Ē is the average (mean) beta and gamma energies per disintegration, in MeV, weighted in proportion to the activity of the radionuclides in the reactor coolant. The RCS initial activity used in the dose analysis is provided below:

Isotope	Initial RCS Inventory (Ci)	Isotope	Initial RCS Inventory (Ci)	Isotope	Initial RCS Inventory (Ci)
I-131	6.8E+01	Kr-83M	1.1E+02	Xe-131M	1.0E+03
I-132	1.0E+01	Kr-85M	4.9E+02	Xe-133M	1.3E+03
I-133	1.8E+01	Kr-85	4.1E+03	Xe-133	9.0E+04
I-134	9.5E-01	Kr-87	2.7E+02	Xe-135M	1.0E+02
I-135	5.3E+00	Kr-88	8.4E+02	Xe-135	2.6E+03
				Xe-138	1.6E+02

Note: The initial iodine isotopic inventory was reduced to reflect the 31.4% total flashing fraction.

RAI 5 [H]

Provide the results as well as all the necessary inputs required to determine the RCS concurrent iodine spike isotopic appearance rates and total production for the duration of the assumed spike.

Duke Energy Response

In order to maximize the RCS concurrent iodine spike isotopic appearance rates, assumptions were made to maximize iodine removal rates from the RCS. Iodine removal mechanisms considered include:

- RCS leakage (TS limits of identified and unidentified leakage measured at procedural

reference conditions)
- Maximum letdown flow rate
- Letdown purification demineralizer in operation throughout the cycle
- Retention in the pressurizer region

The calculated equilibrium removal rates are:

- I-131 equilibrium removal rate is 3.3E+01 Ci per hour
- I-132 equilibrium removal rate is 4.7E+01 Ci per hour
- I-133 equilibrium removal rate is 6.8E+01 Ci per hour
- I-134 equilibrium removal rate is 7.9E+01 Ci per hour
- I-135 equilibrium removal rate is 6.2E+01 Ci per hour

A spike multiplier of 500 is then applied to the equilibrium rate. The concurrent iodine spike appearance rates used in the dose analysis are provided below. Note that these rates have been reduced to reflect the 31.4% total flashing fraction.

- I-131 appearance rate is 5.1E+03 Ci per hour
- I-132 appearance rate is 7.4E+03 Ci per hour
- I-133 appearance rate is 1.1E+04 Ci per hour
- I-134 appearance rate is 1.2E+04 Ci per hour
- I-135 appearance rate is 9.7E+03 Ci per hour

These iodine spike appearance rates are constant, and continue for the duration of the accident (releases from the break are isolated at approximately 26 minutes).

RAI 6 [H]

BACKGROUND:

The HELB report states for the Unit 1 extraction steam system the failure of column G-17 should not result in structural damage that would block the pre-defined repair pathway. Therefore, damage repairs to restore low-pressure service water (LPSW) remain available.

ISSUE:

The phrase in the HELB report "should not result in failure" leaves the possibility that the column would result in failure. Other portions of the HELB report identify a column that could fail and then address the impact of the column failing. The failure of column G-17 may impact the predefined repair cable routing pathway utilized in the damage repair procedure for providing direct current (DC) power to the emergency 4160 volt 0/) switchgear. However, an alternate pathway for the cable routing remains available to effect repairs.

REQUEST:

Provide a description of the consequences of the failure of Column G-17 and the impact on the plant's ability to restore the LPSW system.

Provide the damage repair procedure that addresses the potential consequences of the failure of Column G-17.

Duke Energy Response

The consequences of the failure of Turbine Building Column G-17 due to postulated HELB 1ES-020-R-5 are documented in Calculations OSC-7516.09 and OSC-7516.10 (HELB Report ONDS-351, Revision 2 – References 10.2.12 & 10.2.13) and summarized on Page 4 of Table 4.2-3 of the

HELB Report. There are two (2) types of adverse interactions that result from the failure of Column G-17. These include:

- Loss of Shutdown Equipment (Collateral Damage) due to the interaction of the column and/or generated structural & equipment debris
- The indirect loss of Shutdown Equipment caused by the resulting Turbine Building flood

The Shutdown Equipment adversely affected by the direct interaction with the failed Column G-17 and/or generated structural or equipment debris is:

- Loss of the Unit 1 Main Condenser "1A" & subsequent loss of inventory from the hotwell. *This results in a loss of the Unit 1 EFW suction source.*
- Rupture of the 78 inch Condenser Circulating Water (CCW) pipe line, containing CCW Valve 1CCW-14, at the connection to the Unit 1 Main Condenser
- Rupture of the 6 inch Emergency Feedwater (EFW) pipe line between valve 1FDW-313 and the Auxiliary Building and downstream of valve 1FDW-373. This rupture prevents the feeding of the "1A" Steam Generator from any Unit 1 EFW source and from any cross connection sources.
- Loss of cable trays B-100b, B-109, B-109a, and B-144
- Loss of cable tray A-102a and subsequent loss of the "B" LPSW Pump
- Loss of electrays from cable trays A-102a, A-111, and A-113b

The Shutdown Equipment indirectly adversely affected from the Turbine Building flooding includes:

- Emergency Feedwater Pumps (all units)
- Low Pressure Service Water (LPSW) Pumps (all units)
- Engineered Safeguards (all units)

The identified Shutdown Sequence for postulated HELB 1ES-020-R-5 is provided on Pages 4-28 4-29, 4-45, & 4-52 of the HELB Report, *and the description of the collateral damage is provided on* Page 8-10 of the HELB Report. Since the resulting Turbine Building flood causes the loss of the LPSW pumps on each unit, replacement of the pump motors is required in order to re-establish the functionality of the LPSW System. There are pre-defined pathways for the replacement of these pump motors. If the primary pathway is blocked, due to the structural debris from the postulated failure of Column G-17, repairs to the LPSW pumps would be accomplished by using an alternate pathway away from the debris area or delayed until debris is cleared.

Page 8-10 of the HELB Report (ONDS-351) will be revised to be consistent with the response to this RAI.

The damage repair procedures utilized to restore the LPSW and CCW Systems are the following:

- Emergency Plan Procedure, RP/0/B/1000/022 – Procedure for Major Site Damage Assessment and Repair, ONS Units 1, 2, & 3
- Emergency Procedure, OP/0/A/1102/024 – Plant Assessment and Alignment Following Major Site Damage, ONS Units 1, 2, & 3
- Emergency Procedure, OP/0/A/1102/025 – Cooldown Following Major Site Damage, ONS Units 1, 2, & 3
- Emergency Procedure, IP/0/A/0050/002 – Site Damage Control Procedure, ONS Units 1, 2, & 3
- Emergency Procedure, MP/0/A/3009/012 - Emergency Plan for Replacement of HPI, LPI, and LPSW Motors Following Damage in Turbine Building or Auxiliary Building, ONS Units 1, 2, & 3.

These procedures (References 10.3.21 through 10.3.25, respectively, in the ONS UFSAR HELB Report (ONS-351)), are referenced within the text of the HELB Report as used in the Shutdown Sequence for the postulated HELBs. These procedures have been revised to incorporate the restoration of the LPSW and the CCW Systems following postulated HELBs in the Turbine Building, which result in potential obstruction of the primary pathway to the equipment. These procedures will be uploaded to the SharePoint site when completed.

RAI 7 [H]

BACKGROUND:

The HELB report stated that the Unit 1 main feedwater system states the following:

- *Sub-break 9 interacts with Column G-23 and may result in its failure.*
- *The failure of Column G-23 is not expected to block the pre-defined repair pathway to replace the LPSW pump motors.*

ISSUE:

The phrase "is not expected to block the pre-defined repair pathway," leaves the possibility that the failure of column G-23 would block the pre-defined repair pathway. Other portions of the HELB report identify a column that could fail and then addresses the impact of the column failing. For example, for the Unit 2 main feedwater system the failure of the column may impact the pre-defined repair cable routing pathway utilized in the damage repair procedure for providing DC power to the emergency 4160V switchgear. However, an alternate pathway for the cable routing remains available to effect repairs.

REQUEST:

Provide a description of the consequences of the failure of column G-23 and the impact on the ability to restore the LPSW system.

Provide the damage repair procedure that addresses the potential consequences of the failure of column G-23.

Duke Energy Response

The consequences of the failure of Turbine Building Column G-23 due to postulated HELB 1FDW-031-R-9 are documented in Calculations OSC-7516.09 and OSC-7516.10 (HELB Report ONDS-351, Revision 2 – References 10.2.12 & 10.2.13) and summarized on Page 4 of Table 4.2-4 of the HELB Report. There are two (2) types of adverse interactions that result from the failure of Column G-23. These include:

- Loss of Shutdown Equipment (Collateral Damage) due to the interaction of the column and/or generated structural & equipment debris
- The indirect loss of Shutdown Equipment caused by the resulting Turbine Building flood

The Shutdown Equipment adversely affected by the direct interaction with the failed Column G-23 and/or generated structural or equipment debris is:

- Loss of all Unit 1 EFW System due to damage to the Upper Surge Tank suction source
- Loss of the "B" LPSW Pump due to adverse interactions with Cable Tray A-102a

The Shutdown Equipment indirectly adversely affected from the Turbine Building flooding includes:

- Emergency Feedwater Pumps (all units)
- Low Pressure Service Water (LPSW) Pumps (all units)
- Engineered Safeguards (all units)

The identified Shutdown Sequence for postulated HELB 1FDW-031-R-9 is provided on Pages 4-31, 4-32, 4-46, & 4-53 of the HELB Report. The description of the collateral damage is provided on

Page 8-11 of the HELB Report. Since the resulting Turbine Building flood causes the loss of the LPSW pumps on each unit, replacement of the pump motors is required in order to re-establish the functionality of the LPSW System. There are pre-defined pathways for the replacement of these pump motors. If the primary pathway is blocked, due to the structural debris from the postulated failure of Column G-23, repairs to the LPSW pumps would be accomplished by using an alternate pathway away from the debris area or delayed until debris is cleared.

Page 8-11 of the HELB Report (ONDS-351) will be revised to be consistent with the response to this RAI.

The damage repair procedures utilized to restore the LPSW and CCW Systems are the following:

- Emergency Plan Procedure, RP/0/B/1000/022 – Procedure for Major Site Damage Assessment and Repair, ONS Units 1, 2, & 3
- Emergency Procedure, OP/0/A/1102/024 – Plant Assessment and Alignment Following Major Site Damage, ONS Units 1, 2, & 3
- Emergency Procedure, OP/0/A/1102/025 – Cooldown Following Major Site Damage, ONS Units 1, 2, & 3
- Emergency Procedure, IP/0/A/0050/002 – Site Damage Control Procedure, ONS Units 1, 2, & 3
- Emergency Procedure, MP/0/A/3009/012 - Emergency Plan for Replacement of HPI, LPI, and LPSW Motors Following Damage in Turbine Building or Auxiliary Building, ONS Units 1, 2, & 3

These procedures are References 10.3.21 – 10.3.25, respectively, in the ONS UFSAR HELB Report (ONS-351) and these procedures are referenced within the text of the HELB Report as used in the Shutdown Sequence for the postulated HELBs. These procedures have been revised to incorporate the restoration of the LPSW and the CCW Systems following postulated HELBs in the Turbine Building that result in potential obstruction of the primary pathway to the equipment. These procedures will be uploaded to the SharePoint site when completed.

RAI 8 [H]

BACKGROUND:

The HELB report states that the Unit 1 main feedwater system states the following:

- *Sub-break 7 interacts with Column Ga-24 and may result in its failure however collateral damage from the failure of Column Ga-24 may result in a rupture to the circulating cooling water (CCW) piping leading to the turbine building flooding.*
- *The failure of Column Ga-24 may result in debris blocking the pre-defined repair pathway to replacement of the A LPSW pump motor. The pathway to the C LPSW pump remains available. Plant damage repair procedures will need to be revised to include the option of replacing and re-powering the C LPSW pump motor.*

ISSUE:

ONS does not have procedures in place that direct the plant staff to perform actions that may be required in the event Column Ga-24 fails as a result of sub-break 7.

REQUEST:

Provide a description of the consequences of the failure of Column Ga-24. Provide the damage repair procedure that addresses the potential consequences of the failure of Column Ga-24.

Duke Energy Response

The consequences of the failure of Turbine Building Column Ga-24 due to postulated HELB 1FDW-031-R-7 are documented in Calculations OSC-7516.09 and OSC-7516.10 (HELB Report ONDS-351, Revision 2 – References 10.2.12 & 10.2.13) and summarized on Page 3 of Table 4.2-4 of the HELB Report. There are two (2) types of adverse interactions that result from the failure of Column G-23. These include:

- Loss of Shutdown Equipment (Collateral Damage) due to the interaction of the column *and/or generated structural & equipment debris*
- The indirect loss of Shutdown Equipment caused by the resulting Turbine Building flood

The Shutdown Equipment adversely affected by the direct interaction with the failed Column Ga-24 and/or generated structural or equipment debris is:

- Loss of the 1A MDEFW Pump from failure of valve LPSW-516
- Loss of LPSW essential Header "B" & Valve 1LPSW-139
- Loss of the "B" LPSW Pump

The Shutdown Equipment indirectly adversely affected from the Turbine Building flooding includes:

- Emergency Feedwater Pumps (all units)
- Low Pressure Service Water (LPSW) Pumps (all units)
- Engineered Safeguards (all units)

The identified Shutdown Sequence for postulated HELB 1FDW-031-R-7 is provided on pages 4-31, 4-32, 4-46, 4-52, & 4-53 of the HELB Report, and the description of the collateral damage is provided on Page 8-11 of the HELB Report. Since the resulting Turbine Building flood causes the loss of the LPSW pumps on each unit, replacement of the pump motors is required in order to re-establish the functionality of the LPSW System. There are pre-defined pathways for the replacement of these pump motors. If the primary pathway is blocked, due to the structural debris from the postulated failure of Column Ga-24, repairs to the available LPSW pumps (1A &1C) would be accomplished by using an alternate pathway away from the debris area or delayed until debris is cleared.

The damage repair procedures utilized to restore the LPSW and CCW Systems are the following:

- Emergency Plan Procedure, RP/0/B/1000/022 – Procedure for Major Site Damage Assessment and Repair, ONS Units 1, 2, & 3
- Emergency Procedure, OP/0/A/1102/024 – Plant Assessment and Alignment Following Major Site Damage, ONS Units 1, 2, & 3
- Emergency Procedure, OP/0/A/1102/025 – Cooldown Following Major Site Damage, ONS Units 1, 2, & 3
- Emergency Procedure, IP/0/A/0050/002 – Site Damage Control Procedure, ONS Units 1, 2, & 3
- Emergency Procedure, MP/0/A/3009/012 - Emergency Plan for Replacement of HPI, LPI, and LPSW Motors Following Damage in Turbine Building or Auxiliary Building, ONS Units 1, 2, & 3

These procedures (References 10.3.21 through 10.3.25, respectively, in the ONS UFSAR HELB Report (ONS-351)), are referenced within the text of the HELB Report as used in the Shutdown Sequence for the postulated HELBs. These procedures have been revised to incorporate the restoration of the LPSW and the CCW Systems following postulated HELBs in the Turbine Building that result in potential obstruction of the primary pathway to the equipment. The revisions to these damage repair procedures (HELB Report ONDS-351, Revision 2 through References 10.3.21 to 10.3.25) also include the use of the Units 1 & 2 LPSW "C" Pump in the procedures, as an alternate means of restoring the functionality of the LPSW System. These procedures will be uploaded to the SharePoint site when completed.

Page 8-11 of the HELB Report (ONDS-351) will be revised to remove the ambiguous statement of needing to revise procedures. The revised statement will be consistent with this RAI response.

RAI 9 [H]

BACKGROUND:

The HELB report in the Unit 3 LAR states the following for the Unit 1 main feedwater system:

Sub-break 11 interacts with Column K-23 and may result in its failure. The failure of Column K-23 is not expected to block the pre-defined repair pathways for LPSW pump motor replacement or the pre-defined repair pathway for cable routing to the low-pressure injection (LPI) and LPSW pump motors.

ISSUE:

The phrase "not expected to block the pre-defined repair pathway," leaves the possibility that the column would block the pre-defined repair pathway if the column fails. Other portions of the HELB report identified columns that could fail and then addressed the impact on their failure. The HELB report is not clear on the pre-defined repair pathway following an HELB which results in the failure of Column K-23.

REQUEST:

Provide a description of the consequences of the failure of Column K-23 and the impact on the plant's ability to restore the LPSW system.

Provide the damage repair procedure to address the potential consequences of the failure of Column K-23.

Duke Energy Response

The consequences of the failure of Turbine Building Column K-23 due to postulated HELB 1FDW-031-R-11 are documented in Calculations OSC-7516.09 and OSC-7516.10 (HELB Report ONDS-351, Revision 2 – References 10.2.12 & 10.2.13) and summarized on Page 4 of Table 4.2-4 of the HELB Report. There are two (2) types of adverse interactions that result from the failure of Column K-23. These include:

- Loss of Shutdown Equipment (Collateral Damage) due to the interaction of the column and/or generated structural and equipment damage
- The indirect loss of Shutdown Equipment caused by the resulting Turbine Building flood

The Shutdown Equipment adversely affected by the direct interaction with the failed Column K-23 and/or generated structural or equipment debris is:

- Rupture of a 42 inch CCW pipe line and causing a Turbine Building flood
- Loss of the Unit 1 EFW suction inventory due to the rupture of several Condensate System pipes
- Loss of Panel 1LS1, LOCA Load Shed Relay Panel
- Loss of the 4160 VAC Bus 1TE Switchgear

- Loss of the "A" Chiller Control Panel causing the loss of redundancy of the Unit 1 & 2 Control Room cooling
- Cable Trays 1ENI3418 & 1ENI3422 associated with pressure switches that provide input to the RPS circuitry

The Shutdown Equipment indirectly adversely affected from the Turbine Building flooding includes:

- Emergency Feedwater Pumps (all units)
- Low Pressure Service Water (LPSW) Pumps (all units)

The identified Shutdown Sequence for postulated HELB 1FDW-031-R-11 is provided on Pages 4-31, 4-32, 4-46, & 4-53 of the HELB Report, and the description of the collateral damage is provided on Pages 8-11 & 8-12 of the HELB Report. Since the resulting Turbine Building flood causes the loss of the LPSW pumps on each unit, replacement of the pump motors is required in order to re-establish the functionality of the LPSW System. There are pre-defined pathways for the replacement of these pump motors. If the primary pathway is blocked, due to the structural debris from the postulated failure of Column K-23, repairs to the LPSW pumps would be accomplished by using an alternate pathway away from the debris area or delayed until debris is cleared.

Pages 8-11 and 8-12 of the HELB Report (ONDS-351) will be revised to be consistent with the RAI response.

The damage repair procedures utilized to restore the LPSW and CCW Systems are the following:

- Emergency Plan Procedure, RP/0/B/1000/022 – Procedure for Major Site Damage Assessment and Repair, ONS Units 1, 2, & 3
- Emergency Procedure, OP/0/A/1102/024 – Plant Assessment and Alignment Following Major Site Damage, ONS Units 1, 2, & 3
- Emergency Procedure, OP/0/A/1102/025 – Cooldown Following Major Site Damage, ONS Units 1, 2, & 3
- Emergency Procedure, IP/0/A/0050/002 – Site Damage Control Procedure, ONS Units 1, 2, & 3
- Emergency Procedure, MP/0/A/3009/012 - Emergency Plan for Replacement of HPI, LPI, and LPSW Motors Following Damage in Turbine Building or Auxiliary Building, ONS Units 1, 2, & 3

These procedures (References 10.3.21 through 10.3.25, respectively, in the ONS UFSAR HELB Report (ONS-351)), are referenced within the text of the HELB Report as used in the Shutdown Sequence for the postulated HELBs. These procedures have been revised to incorporate the restoration of the LPSW and the CCW Systems following postulated HELBs in the Turbine Building that result in potential obstruction of the primary pathway to the equipment. These procedures will be uploaded to the SharePoint site when completed.

RAI 10 [H]

BACKGROUND:

The HELB report in the Unit 3 LAR states the following for the Unit 2 condensate system:

The failure of either column (H-32 or H-33a) may impact the pre-defined repair cable routing pathway utilized in the damage repair procedures. An alternate pathway must be determined.

ISSUE:

The phrase "an alternate pathway must be determined" leaves open the question of what will ONS do if there is a column failure.

REQUEST:

Explain why the damage control procedures do not identify the alternate pathway.

Provide a description of what actions will be taken to prepare for the possibility of the loss of the pre-defined repair pathway.

Duke Energy Response

Prior to the Unit 3 HELB LAR release date, the plant damage assessment and repair procedures had not been reviewed for all HELB scenarios that may impact pre-defined motor/cable replacement pathways. Plant walkdowns have since been performed and alternate pathways or plant modifications have been identified for all relevant HELB scenarios.

Plant damage assessment and repair procedures are being revised to address alternate cable/motor replacement pathways for HELB scenarios that may affect the pre-defined repair pathways (see responses to RAIs 6 – 9 for list of procedures). After revision, these procedures will be uploaded to the Shareware site for NRC review. The related plant modifications are committed items as described in commitments 30H, 38H and 44H.

RAI 11 [H]

BACKGROUND:

The HELB report in the Unit 3 LAR states the following for the Unit 2 extraction steam system:

Running break 2-ES-024-R is on 42-inch 2C steam extraction pipe. The failure of the column may impact the pre-defined repair pathway for motor replacement and power cable routing for the 3A LPSW Pump, should it be needed.

ISSUE:

The phrase "may impact the pre-defined pathway" leaves the possibility that the failure will impact the pre-defined pathway.

REQUEST:

Provide a description of what actions will be taken to prepare for the possibility of the loss of the pre-defined repair pathway.

Duke Energy Response

Prior to the Unit 3 HELB LAR release date, the plant damage assessment and repair procedures had not been reviewed for all HELB scenarios that may impact pre-defined motor/cable replacement pathways. Plant walkdowns have since been performed and alternate pathways or plant modifications have been identified for all relevant HELB scenarios.

Plant damage assessment and repair procedures are being revised to address alternate cable/motor replacement pathways for HELB scenarios that may affect the pre-defined repair pathways (see responses to RAIs 6 – 9 for list of procedures). After revision, these procedures will be uploaded to the Shareware site for NRC review. The related plant modifications are committed items as described in commitments 30H, 38H and 44H.

RAI 12 [H]

BACKGROUND:

The HELB report states the following for the Unit 2 extraction steam system:

"Running break 2-ES-20-R is on a 36-inch..."

"Sub-break 3 interacts with Column H-39 and may result in its failure. The failure of the column may impact the pre-defined repair pathway for motor replacement and power cable routing for the 3A LPSW Pump, if needed."

ISSUE:

For the potential failure of Column H-39, the HELB report is unclear on the pre-defined repair pathway.

REQUEST:

Provide a description of what actions will be taken for the possibility of the loss of the predefined pathway.

Duke Energy Response

Prior to the Unit 3 HELB LAR release date, the plant damage assessment and repair procedures had not been reviewed for all HELB scenarios that may impact pre-defined motor/cable replacement pathways. Plant walkdowns have since been performed and alternate pathways or plant modifications have been identified for all relevant HELB scenarios.

Plant damage assessment and repair procedures are being revised to address alternate cable/motor replacement pathways for HELB scenarios that may affect the pre-defined repair pathways (see responses to RAIs 6 – 9 for list of procedures). After revision, these procedures will be uploaded to the Shareware site for NRC review. The related plant modifications are committed items as described in commitments 30H, 38H and 44H.

RAI 13 [H]

The licensee's response to RAI 2 did not include a commitment to meet all of the criteria in Branch Technical Position (BTP) Mechanical Engineering Branch (MEB) 3-1, Revision 2, as requested in part (a) of RAI 2, despite the continued application of portions of the BTP. Nor did the response provide a detailed comparison of the full criteria contained in BTP MEB 3-1 with the ONS proposed LAR HELB criteria, as requested in Part (b).

a) Please provide a detailed comparison of the full criteria contained in BTP MEB 3-1 with the ONS proposed LAR HELB criteria.

   The licensee's criteria for defining pipe break locations lacks the provisions found in the Giambusso Letter that breaks are defined where thermal stresses alone exceed $0.8S_A$.

b) Provide a commitment to define breaks where thermal stresses alone exceed $0.8S_A$, or justify not doing so.

   The licensee's response to RAI 2 states in the discussion of postulation of critical cracks:

   "A further enhancement is provided for portions of the MS [main stream] and MFDW [main feedwater] Systems located in the [Auxiliary Building] AB. These systems receive periodic volumetric inspections at all accessible girth welds locations and adjacent base metal to provide early warning of potential degradation in these systems that might result in the

formation of a break or crack."

c) Please clarify what is being done to assure the integrity at inaccessible girth weld locations and provide specific data identifying the locations and number of inaccessible locations.

Duke Energy Response

The current licensing basis for the Oconee Station for High Energy Line Breaks is the Giambusso/ Schwencer letters. Oconee is proposing adoption of elements of the Standard Review Plan (SRP) and BTP MEB 3-1, where practical, or where clarification of licensing approaches is available.

(a) The requested information is given in the Attachment to this submittal.

(b) In the absence of primary stress, secondary stress, such as thermal, is a poor predictor of potential pipe failure locations. Primary stress is needed to cause a potential pipe failure. The ASME Code Section NB-3213.8 (1977 edition) defines primary stress as follows: "Any normal or a shear stress developed by an imposed loading which is necessary to satisfy the laws of equilibrium of external and internal forces and moments. The basic characteristic of a primary stress is that it is not self-limiting. Primary stresses which considerably exceed the yield stress will result in failure or, at least, in gross distortion."

ASME Code NB-3213.13 defines thermal stress as follows: "Thermal stress is a self balancing stress produced by a non-uniform distribution of temperature or by differing thermal coefficients of expansion. Thermal stress is developed in a solid body whenever a volume of material is prevented from assuming the size and shape that it normally should under a change in temperature."

In section NB-3213.13(b), the Code notes: "Local thermal stress is associated with almost complete suppression of the differential expansion and thus produces no significant distortion. Such stresses shall be considered only from the fatigue standpoint and are therefore classified as local stresses in Table NB-3217-1." Since thermal stress is self balancing, thermal stress which exceeds the yield stress will not result in failure. Repeating cycles of thermal stress exceeding the yield stress may result in cracking due to fatigue, however, the potential for critical crack formation is addressed by the postulation of critical cracks where the actual stress exceeds the crack stress threshold of $.4 \times (S_A + S_H)$.

Giambusso/Schwencer included the requirement to postulate break locations where the actual stress exceeded $.8S_A$. However, BTP MEB 3-1 includes no such requirement. Duke Energy concluded that the omission of the thermal stress threshold in BTP MEB 3-1 is recognition by the regulatory authorities that thermal stress, in the absence of primary stress, cannot cause pipe rupture failures.

(c) Inaccessible girth welds are enclosed by the MFDW guard pipes adjacent to Reactor Building penetrations 25 & 27. The guard pipes form part of the MFDW rupture restraints as described in Section 8 (item 5) of ONDS-351. The inaccessible girth welds are present in Units 1 & 2, but not in Unit 3. For Units 1 & 2, the MFDW A header(s) include an 18 degree elbow located just upstream of RB penetration 27 and the MFDW rupture restraint. While the upstream girth weld of the 18 degree elbow is accessible and volumetrically inspected once during each 10 year ASME Section XI in-service inspection interval, the downstream girth weld is enclosed by the aforementioned guard pipe. Similarly, the Units 1 & 2 MFDW B header(s) include a 32 degree elbow located just upstream of the RB penetration 25 and the MFDW rupture restraint. Again, the upstream girth weld of the elbow is accessible and volumetrically inspected once during each 10 year ASME Section XI in-service inspection interval, the downstream girth weld is enclosed by the aforementioned guard pipe. The Unit 3 headers contain no such elbows, and as such there are no girth welds enclosed by the MFDW rupture restraint guard pipe.

As described in ONDS-351 (Section 8, Item 5), each MFDW guard pipe encloses the postulated MFDW break location(s). Since these downstream elbow girth welds are adjacent to the postulated break location inside the guard pipe, assuming a break at the inaccessible weld(s) would result in no greater consequences than those that would occur for break(s) postulated inside the guard pipe.

RAI 14 [H]

Based on the licensee's response to RAI 3 (items a), b), and c)), the following additional item is requested with regards to RAI 3:

Please provide the following information:

For every system classified as moderate-energy based on the 1 percent of total plant run time, provide the total time spent at high-energy conditions and the total time spent operating. In addition, provide the total time the plant ran during the same time interval.

These times can be taken from the time interval researched in the previous RAI submittal:

- For Unit 1: From 7/8/1999 to 6/1/2008
- For Unit 2: From 12/16/1999 to 12/12/2008
- For Unit 3: From 5/21/2000 to 11/11/2008

Duke Energy Response

In accordance with ONDS-351, Analysis of Postulated HELBs Outside of Containment, Duke does not postulate pipe ruptures or "critical cracks" in high energy lines that operate at high energy conditions less than 1% of the total plant (unit) operating time (Normal Plant Conditions). Normal Plant Conditions have been defined as operation in Modes 1, 2, 3 and 4.

Systems excluded using the 1% criterion were emergency systems. The emergency systems include, Emergency Feedwater (EFW), Reactor Building Spray (RBS), the 'C' High Pressure Injection (HPI) pump discharge, and the Standby Shutdown Facility (SSF) Auxiliary Service Water (ASW). These systems are operated following plant emergencies or for surveillance testing. When these systems are operating, they always operate in the high energy state. Therefore, normal plant startup and shutdown sequences and the associated times spent in the different modes do not determine the time the emergency systems are exposed to high energy conditions. A time interval of 1581 days (from 1/1/2005 to 5/1/2009) was selected to provide a representative historical period for review of the various systems. The time interval was judged to be of sufficient duration to reflect typical high energy operating times.

1% Exclusions – Time Spent in High Energy (1/1/2005 to 5/1/2009)

	Unit 1 (days)	Unit 2 (days)	Unit 3 (days)
'A' Motor Driven EFW Pump Discharge	2.9	1.8	1.1
'B' Motor Driven EFW Pump Discharge	2.6	1.3	1.2
Turbine Driven EFW Pump Discharge	2.5	2.9	3.1
'A' RBS Pump Discharge	0.9	0.8	0.7
'B' RBS Pump Discharge	0.8	0.7	0.7
'C' HPI Pump Discharge	1.9	1.5	0.9

The SSF ASW is an emergency system that supports all three units. The SSF ASW Pump discharge was operated in a high energy condition for approximately 3.2 days during the same time interval of 1581 days (from 1/1/2005 thru 5/1/2009).

The total operating time spent in Modes 1 through 4 for each unit within the time interval from 1/1/2005 to 5/1/2009 is provided below:

- Unit 1 Total Operating Time in Modes 1 through 4 was approximately 1440 days.
- Unit 2 Total Operating Time in Modes 1 through 4 was approximately 1480 days.
- Unit 3 Total Operating Time in Modes 1 through 4 was approximately 1500 days.

RAI 15 [H]

For the licensee's response to RAI 4(b), please include within the body of the text, references to the specific documentation that supports the discussion of field walk downs, piping interactions, break analyses, and mitigation of piping break effects.

Duke Energy Response

The report ONDS-351 includes reference 10.3.17, "HELBs Outside Containment Walkdown Criteria & Requirements." This was the procedure used to conduct plant surveys to determine the potential for high energy line breaks to affect safe shutdown target equipment. The locations of HELBs are documented in ONDS-351 reference(s) 10.2.2 (Calculation OSC 7516.01, ONS Unit 1 High Energy Line Break Stress Evaluation), 10.2.39 (Calculation OSC 7517.01, ONS Unit 2 High Energy Line Break Stress Evaluation), and 10.2.52 (Calculation OSC 7518.01, ONS Unit 3 High Energy Line Break Stress Evaluation). The results of the plant surveys are documented in ONDS-351 references 10.2.6 (Calculation OSC 7516.02, ONS - Unit 1 - Pipe Rupture Evaluation HELB Outside Containment Plant Walkdowns), 10.2.40 (Calculation OSC 7517.02, ONS - Unit 2 - Pipe Rupture Evaluation HELB Outside Containment Plant Walkdowns) , and 10.2.53 (Calculation OSC7518.02, ONS - Unit 3 - Pipe Rupture Evaluation HELB Outside Containment Plant Walkdowns). These calculations document the potential for high energy line breaks to affect safe shutdown target equipment and piping. The safe shutdown equipment and piping is documented in ONDS-351 references 10.2.4 (Calculation 8089.01, High Energy Line Break (HELB) Safe Shutdown Target List (SSTL) - ONS Units 1, 2, & 3)) and 10.2.15 (Calculation 8089.02, High Energy Line Break (HELB) Safe Shutdown Target List (SSTL) Pressure Boundary Piping (ONS Units 1, 2, & 3)).

These calculations do not provide the mitigation strategy for each documented high energy line break and the potentially affected safe shutdown target equipment and piping. As stated within ONDS-351 Section 1.1, the analysis of high energy line break interaction(s) and the pathways to Safe Shutdown / Cold Shutdown is based upon the station configuration following the completion of HELB modifications described in Section 9.0 of the report. The analysis of the mitigation of high energy line breaks is contained in Section 4 (Unit 1), Section 5 (Unit 2) and Section 6 (Unit 3) respectively of ONDS-351.

RAI 16 [H]

In response to RAI 5, the licensee judged that the energy contained in the 1.5-inch and 2-inch high energy (HE) piping as being insufficient to damage adjacent piping systems or structural components. Please identify the technical evaluation or reference that supports this basis?

In addition,

a) How many feet of HE piping in excess of a 1 nominal pipe size (nps) lower limit are there in the plants? List lengths for each size in excess of 1 nps.

b) Are there any restrictions between the HE piping in excess of 1 nps and the ultimate gas source?

c) The Electro Hydraulic Control systems are not mentioned in the detailed response. Please discuss why this piping has been eliminated from the HE candidates?

Duke Energy Response

This RAI is related to the nitrogen and Electro-Hydraulic Control (EHC) systems.

The nitrogen system consists of ten horizontal supply tanks located outside the Turbine Building. These tanks are normally pressurized to approximately 2000 psig. These tanks supply the nitrogen headers located inside the Turbine Building and the Auxiliary Building. Supply from the tanks is provided by ¾ inch nominal pipe size (nps) piping to a pressure reducing valve that regulates the downstream piping pressure to approximately 625 psig. The pressure reducing valve is also located outside the Turbine Building. The downstream piping increases in size to 1.5 inch nps piping before it enters the Turbine Building. There is approximately 220 feet of the 1.5 inch nps high pressure nitrogen piping inside the Turbine Building. The high pressure nitrogen supply piping then reduces in size to 1 inch nps. The 1 inch nitrogen supply piping is routed to the Auxiliary Building from the Turbine Building. There are two locations inside the Auxiliary Building on the 2nd Floor Hallway where the high pressure nitrogen piping increase in size from 1 inch nps to 2 inches nps. Any ruptures in the 1.5 inch or 2 inch nitrogen piping would be limited by the ¾ inch pressure reducing valve located outside the Turbine Building.

The EHC system is located in the Turbine Building basement for each unit. The EHC system is an oil system that is normally pressurized to approximately 1600 psig. There are two EHC pumps per unit that can provide the source for high pressure. Only one pump per unit is normally operating. Each pump has a design flow rate of 53 gpm at a discharge pressure of 1600 psig. The largest size of high pressure piping in the EHC system is 1.5 inch nps. Any ruptures in the 1.5 inch EHC piping would be limited by the capacity of the EHC pumps.

Breaks were not postulated in the EHC system due to the limited potential for breaks in the system to cause pipe whips and jet impingement loads that could severely damage systems, structures, and components necessary to safely achieve a safe shutdown state. Since the system operates at less than the saturation point of the fluid, the discharge jet is characterized by a nearly constant jet approximately equal to the break diameter. In addition, given the substantial viscosity of the EHC fluid, as compared to water, the friction losses in the system are greater than that for comparable steam, saturated water, and sub-cooled water systems. This increase in frictional losses will result in a smaller steady state thrust coefficient, limiting the magnitude of the discharge jet. The combination of these factors, along with the relative small size of the EHC system piping, provides reasonable assurance that a break in the EHC system will not adversely affect systems, structures, and components in the vicinity.

RAI 17 [H]

In response to RAI 6(a), the licensee states that "Giambusso/Schwencer does address the postulation of terminal end breaks at isolation valves for Class 1 piping."

a) Provide and fully reference specific statements from criteria that discuss isolation valves and, for each instance/location where such end breaks are postulated, demonstrate compliance with the criteria.

The licensee states that "Giambusso/Schwencer required the postulation of terminal end breaks at rigidly fixed valves that may act to restrain thermal movement." The licensee also states, "...all isolation valves that serve in this manner are in line valves that are not independently supported or supported in a way that would prohibit piping motion and thermal movement."

b) Please provide documentation and a technical basis that confirms this condition at all isolation valves.

The licensee states that relative to postulating break locations, "The NRC has previously approved this interpretation at the Oconee Nuclear Station for the Passive Low Pressure Injection Cross Connection Modifications."

c) Document similarities which demonstrate applicability to the current ONS LAR on excluding boundary valves from being terminal ends.

Duke Energy Response

Response to 17(a):

Section 2.2.2 of ONDS-351 addresses the postulation of terminal end breaks at isolation valves. It states:

"The postulation of terminal end breaks at the first normally closed valve(s) separating portions of a system maintained pressurized during normal operations and portions of a system not maintained pressurized depends on whether the system has a seismic analysis that is continuous across the valve. For systems or portions of systems that are not seismically analyzed, breaks are postulated to occur at all piping girth welds in the system including those that attach to normally closed valves. For systems or portions of systems that are seismically analyzed, and the analysis is continuous across the normally closed valve, such that stress can be accurately determined, break and crack locations are determined based on comparison to the break and crack stress thresholds."

Giambusso/Schwencer specifies in 2(a) the criteria for the postulation of break locations in each piping run. 2(a)(1) specifies that breaks be postulated at terminal ends. Footnote (3), referenced in 2(a), notes, "A piping run interconnects components such as pressure vessels, pumps, and rigidly fixed valves that may act to restrain pipe movement beyond that required for design thermal displacement." Duke Energy interprets this to mean that break locations should be postulated at rigidly fixed valves, since they can act as the terminus to a piping run, and thus act as a terminal end. In addition, Duke Energy interprets this to mean that break locations should be postulated at normally isolated valves, if such valves are rigidly restrained. As provided in the response to RAI 6(a) there are no isolation valves that serve as the boundary between high energy piping and moderate energy piping that are rigidly supported independent of the piping system. As such no terminal end breaks were postulated at isolation / boundary valves in continuous seismically analyzed systems.

Response to 17(b):

ONDS-351 provides the summary of the analysis of pipe breaks postulated in high energy systems outside containment at Oconee Nuclear Station. The postulation of break locations is found in ONDS-351 reference(s) 10.2.2 (Calculation OSC 7516.01, ONS Unit 1 High Energy Line Break Stress Evaluation), 10.2.39 (Calculation OSC 7517.01, ONS Unit 2 High Energy Line Break Stress Evaluation), and 10.2.52 (Calculation OSC 7518.01, ONS Unit 3 High Energy Line Break Stress

Evaluation). These calculations document break locations at normally closed isolation valves if such valves are included in piping systems or portion of piping systems that were not seismically analyzed. These calculations also document break and crack locations for seismically analyzed lines adjacent to normally closed valves, if the actual stress at those locations exceed the break and crack thresholds. In order to determine the effect of a postulated break, plant surveys were completed. The results of the plant surveys are documented in ONDS-351 references 10.2.6 (Calculation OSC 7516.02, ONS - Unit 1 - Pipe Rupture Evaluation HELB Outside Containment Plant Walkdowns), 10.2.40 (Calculation OSC 7517.02, ONS - Unit 2 - Pipe Rupture Evaluation HELB Outside Containment Plant Walkdowns) , and 10.2.53 (Calculation OSC7518.02, ONS - Unit 3 - Pipe Rupture Evaluation HELB Outside Containment Plant Walkdowns).

Response to 17(c):

Section 2.2.2 of ONDS-351 addresses the postulation of breaks and critical cracks at isolation valves, as follows:

"Breaks & Critical Cracks at closed valves are postulated as follows. The postulation of terminal end breaks at the first normally closed valve(s) separating portions of a system maintained pressurized during normal operations and portions of a system not maintained pressurized depends on whether the system has a seismic analysis that is continuous across the valve. For systems or portions of systems that are not seismically analyzed, breaks are postulated to occur at all piping girth welds in the system including those that attach to normally closed valves. For systems or portions of systems that are seismically analyzed, and the analysis is continuous across the normally closed valve, such that stresses can be accurately determined, break and crack locations are determined based on comparison to the break and crack stress thresholds."

By letter dated September 29, 2003, the NRC staff issued Amendments 335, 335, and 336 for Oconee, Units 1, 2, and 3, to support the installation of a passive Low Pressure Injection (LPI) System cross connects inside containment. For all three units, the amendments approved the use of Standard Review Plan (SRP) 3.6.2 Branch Technical Position MEB 3-1.

The March 20, 2003, LAR (approved by Amendments 335, 335, and 336), describes a boundary valve (xLP-47 and 48) that exists in each LPI train that separate the high energy portion of the system from the moderate energy portion of the system. The submittal continued that normally, in cases where a valve constitutes the boundary between moderate and high energy lines, a terminal end break is postulated per BTP MEB 3-1 B.1.c (1) (a) footnote 3. In the circumstances described, the stress analysis of the LPI system is continuous across the boundary, such that the stress levels can be accurately portrayed for each applicable load case, and as such, no terminal end breaks were postulated at the boundary valve(s). It was further described that this treatment meets the intent of footnote 3, since the piping both upstream and downstream of the boundary valves was included in the same stress analysis model. The Staff acknowledged this request, by noting in Section 3.2 (page 9) of the referenced SER, "...that the piping model that includes the valves satisfies the intent of the footnote in that the valves are modeled in the piping run and they are not independently supported in such a way as to represent a terminal end," The staff provided acceptance of this position on page 10 of the SER.

The application of MEB 3-1 described above is the same as requested by the High Energy Line Break LAR as documented in ONDS-351. For comparison purposes, the request to not treat high energy / moderate energy boundary valves in analyzed piping that includes the seismic loading case is given below:

- The boundary valves described in the HELB submittal are in-line valves not independently supported from the piping system.

- The stress analysis of the piping run(s) that includes the boundary valves described in the HELB submittal is continuous on both the downstream and upstream sides of the valves, such that actual stress for each load case is accurately known.

Finally, as stated in ONDS-351, this request only applies to seismically analyzed piping systems or subsystems. For piping not seismically analyzed breaks are postulated at all piping girth welds, including those between system piping and boundary isolation valves.

RAI 18 [H]

The note in BTP MEB 3-1 discussed in RAI 7 and its response states in part:

"A branch connection to a main piping run is a terminal end of the branch run, except where the branch run is classified as part of a main run in the stress analysis and is shown to have a significant effect on the main run behavior." This is a vintage artifact of the limited analysis capabilities available at the time of the BTP. Model sizes were limited to the point where branch piping was included in a model of run piping, where it had no influence, and was not accurately represented in the model's response.

a) What modeling criteria does the licensee have in place to ensure an accurate response of branch piping that does not influence the response of the run piping, e.g., responds in a significantly different frequency range than the run piping?

A note in RAI 7 states:

> *The NRC staff has, in the past, asked the licensee to clarify that it will satisfy the complete criteria contained in Footnote 3 of BTP MEB 3-1. It does not appear that this has taken place in the proposed LAR. In addition, the NRC staff has previously requested the licensee to compare its proposed HELB criteria with the full criteria contained in BTP MEB 3-1 in order for the NRC staff to perform a thorough safety review of the Duke HELB proposal. The proposed LAR only addresses the criteria from BTP MEB 3-1, which provides relaxations to the Oconee licensing basis HELB criteria.*

b) These two requests are noted as still having not been addressed, and, therefore are still pending.

Duke Energy Response

(a) For analysis purposes, branch lines are those having a diameter less than one-fourth of the run pipe diameter, a moment of inertia of less than 1/25th of the run moment of inertia, or a section modulus less than one-tenth that of the run pipe section modulus. Branch lines meeting any of these criterion were decoupled from the run pipe stress analysis model and evaluated as a separate model with the branch point as one of the boundary points.

Thermal analysis of the decoupled branch line included thermal movements of the run pipe applied as anchor movements to the branch line. Similarly, seismic analysis of the decoupled branch line included inertial displacements and/or seismic anchor motion displacements of the run pipe applied as anchor movements to the branch line.

(b) See response to RAI 13(a).

RAI 19 [H]

Seismic Category I piping is piping classified by application of criteria found in Regulatory Guide 1.29, "Seismic Design Classification." Please provide a list of the seismic category I piping, for which the summary information found in item 4 of the Giambusso letter still needs to be provided and address how the requirements from (a) to (e) of item 4 are met.

Duke Energy Response

There are three Seismic Category I piping systems located outside containment, of which a portion is classified as high energy. Those systems are the High Pressure Injection (HPI) System, the Main Steam (MS) System, and the Main Feedwater (MFDW) System. Giambusso/Schwencer item 4 requested "...that a summary be provided of the dynamic analyses applicable to the design of Category I piping and associated supports which determine the resulting loadings as a result of the postulated pipe break." In the October 23, 2009 response for RAI 8, we noted that the Giambusso letter, on page 1, included the following:

"Since piping layouts are substantially different from plant to-plant, applicants and licensees should determine on an individual basis the applicability of each of the following items for inclusion in their submittals."

In addition it was noted in the October 23, 2009 submittal "that dynamic analyses were performed for the break scenarios that warranted a dynamic analysis." As such, no dynamic analyses were performed for the HPI System for the purposes of designing piping supports and or rupture restraints. The postulated break.locations are as shown in ONDS-351, Figures 4.1-7 (Unit 1), 5.1-7 (Unit 2), and 6.1-7 (Unit 3). For the postulated locations, jet impingement forces were determined in accordance with ANSI/ANS 58.2 -1988, "Design Basis for Protection of Light Water Nuclear Power Plants Against the Effects of Postulated Pipe Rupture". Once the jet impingement forces were determined, plastic hinges were postulated and whip interaction zones established. Following that, surveys were made of the interaction zones to identify any safe shutdown equipment. Identified safe shutdown equipment located within the interaction zones were considered to be damaged and rendered non functional. See response to RAI 15 for further information regarding the evaluation of postulated high energy line breaks.

A similar process was followed for the MS System. Postulated break locations are as shown in ONDS-351, Figures 4.1-8 (Unit 1), 5.1-8 (Unit 2), and 6.1-8 (Unit 3). For the postulated MS break in the East Penetration Room, internal pressurization of the room was determined as described in ONDS-351, Section 8, Item 20.

A similar process was followed for the MFDW System. Postulated break locations are as shown in ONDS-351, Figures 4.1-4 (Unit 1), 5.1-4 (Unit 2), and 6.1-4 (Unit 3). For the postulated MFDW breaks in the East Penetration Room, internal pressurization of the room was determined as described in ONDS-351, Section 8, Item 20.

As stated in ONDS-351 Section 8, item 4, with the exception of the two MFDW rupture restraints, located in the East Penetration Room, evaluations of the effects of whip and jet impingement associated with postulated break locations of Category I piping assumed unrestrained lines. As such, there was no need to determine the dynamic response for breaks in Category I piping, since no supports in the lines were designed to absorb these loads. Rather, the safe shutdown equipment, located in the zone of influence of these breaks were assumed failed and rendered non operational.

The overall mitigation strategy for breaks in Category I systems is the availability of other equipment remote from the postulated break locations that could be used to bring the affected unit to a safe shutdown state. Thus for postulated breaks in Category I systems located in the Auxiliary Building, systems and equipment located in the Turbine Building and or the Standby Shutdown Facility (SSF) would be available to mitigate the break event. Similarly, for postulated breaks in Category I systems located in the Turbine Building, systems and equipment located in the Auxiliary Building and or the SSF would be available to mitigate the break event.

RAI 20 [H]

This question is applicable to the licensee's responses to RAIs 9 and 10.

How does the criteria and methodology used to design containment penetrations under line rupture forces and moments generated by their own rupture compare to the criteria and methodology used with pipe whip restraints in the current HELB evolution?

Duke Energy Response

The design pressure and temperature of the piping systems penetrating containment are used to determine the line rupture forces and moments caused by their own rupture applied to the containment penetration(s). The normal operating pressure and temperature of the high energy systems are used to determine the line rupture forces and moments caused by the postulation of break locations.

RAI 21 [H]

The LAR identifies various sections of the high energy piping that have been excluded due to normal operating temperature and pressure conditions.

Please provide a complete list of excluded high energy piping systems, if such a list cannot be found in the calculation.

Duke Energy Response

High energy lines were excluded from the evaluations if it was shown that the normal operating conditions were below the threshold for high energy. In addition, piping downstream of a normally closed valve in a high energy system was excluded. The normal operating configuration for a high energy system was based on the operating configuration at 100% rated full power. High energy systems that are not normally in operation were excluded. Systems that operate at or below atmospheric pressure were also excluded from the evaluations since these systems were judged to have insufficient energy to create pipe whips or jets. Finally, oil and gas piping were not considered high energy systems since they possess limited energy (see response to RAI 16).

Based on the above information, the following systems or portions of systems were excluded from the evaluation of high energy line breaks:

1. Auxiliary Steam System piping that is normally isolated
2. Condensate System piping that is normally isolated
3. Main Feedwater System piping that is normally isolated
4. 'F' Extraction Steam to 'F' Heaters, including the associated heater vents and drains
5. 'E' Extraction Steam to 'E' Heaters, including the associated heater vents and steam drains
6. 'E' Heater Drains to the 'E' Heater Drain Pumps

7. Portions of the High Pressure Injection System
   - RCP Seal Return piping
   - Letdown piping from the block orifice to the LDST
   - HPI Pump Suction piping from the LDST
   - HPI Pump C Discharge piping
8. Main Steam System piping that is normally isolated
9. Portions of the Moisture Separator Reheater Drain System
   - Outlet from the Moisture Separator Drain Pump Demineralizer Heat Exchanger
   - Piping that is normally isolated
10. Plant Heating System piping that is normally isolated
11. Portions of the Steam Seal Header that operate at or below atmospheric pressure
12. Low Pressure Injection System
13. Reactor Building Spray System
14. Emergency Feedwater System piping
15. Standby Shutdown Facility Auxiliary Service Water System piping
16. Steam Generator Blowdown piping
17. Nitrogen System piping
18. Electro-Hydraulic Control (EHC) System piping (oil system).

RAI 22 [H]

In the response to RAI 12(a), the licensee discussed the new term "Initial Operating Conditions." According to the discussion, this term is consistent with the analysis presented in Section 3.0 of the Mechanical Design Section (MDS) Report OS-73-2."

a) Please provide specific details, including a comparison of the Normal Plant Conditions, defined in Auxiliary Systems Branch (ASB) 3-1 and the Operation Modes defined in HELB report, to demonstrate that the statement is correct and applicable to this situation.

b) In the licensee's response to RAI 12(b), reference is again made to their response to RAI 3. As stated by the NRC staff in RAI 3, a complete list of the systems with a data summary on each should be assembled and made available to reviewers.

Duke Energy Response

The term "Initial Operating Conditions" is defined on Page 1-14 of the HELB Report (ONDS-351). The purpose of having the term "Initial Operating Conditions" is to establish a starting point, which defines the physical configuration of the plant and the plant conditions, when the HELB is postulated to occur. This is done, so that the pathways to a Safe Shutdown condition from the most severe initial conditions can be determined. The only relationship to the plant operating modes is that the HELBs are postulated to occur with the unit in Mode 1(Power Operation) at the 100% rated thermal power condition. The term is consistent with Section 3.0 of the MDS report OS-73-2 (ONDS-351 Reference 10.3.1) in that both documents identify the unit operating at 100% rated thermal power (Full Power) at the time the HELB is postulated to occur. The definition of "Initial Operating Conditions (or Normal Operating Conditions)" is not the same definition as "Normal Plant Conditions" defined on Page 1-15 of the HELB Report.

The term "Normal Plant Conditions," is defined on Page 1-15 of the HELB Report and is based upon the definition of the same name provided on Page 3.6.1-16 of SRP 3.6.1 (ASB 3-1). The

ONS Operational Modes (taken from Table 1.1-1 of the ONS Technical Specifications) are defined on Page 1-14 of the HELB Report. A comparison of terms and ONS Operational Modes is provided below:

ONS Operational Modes (HELB Report Page 1-14)	HELB Report "Normal Plant Conditions" Description (HELB Report Page 1-15)	Definition of "Normal Plant Conditions" SRP 3.6.1 (Page 3.6.1-16)
1	Power Operation	Operation at Power
2	Startup	Reactor Startup
3	Hot Standby	Hot Standby
4	Hot Shutdown	Reactor Cooldown to Cold Shutdown Condition

For the second paragraph of this RAI please refer to the response to RAI 23b.

<u>RAI 23 [H]</u>

a) The licensee states that "Those systems that could be operated at high energy conditions for short periods of time during modes 1 through 4 were excluded." Please provide specific details on the criteria used to qualify "short periods of time," and provide the data that served as the bases for the calculations performed to demonstrate that the stated exclusions are justified.

b) In the licensee's response to RAI 13, reference is again made to their response to RAI 3. As stated by the NRC's staff in RAI 3, a complete list of the systems with a data summary on each should be assembled and made available.

<u>Duke Energy Response</u>

(a) As described in ONDS-351, a number of criteria were employed in the development of the high energy systems in which break locations would be postulated.

1. High energy systems were selected based on operating conditions existing at 100% of rated full power. The high energy boundaries for these systems were selected based on the normal operating configuration of the systems at 100% of rated full power. Piping downstream of a normally closed high energy boundary valve was excluded from high energy break consideration. "Short periods of time" were not applied to these high energy line break exclusions.
2. For systems not normally in operation, "short periods of time" were used to exclude these systems from high energy line break consideration.
   - Pipe breaks and critical cracks are not postulated on high energy lines that operate at high energy conditions less than 1% of the plant operating time during Modes 1 through 4.
   - Pipe breaks and critical cracks are not postulated on high energy lines that operate at high energy conditions less than 2% of the total system operating time.

The details were provided for the systems excluded using "short periods of time during Modes 1 through 4" in the response to RAI 14 of this letter.

b) A complete listing of systems that were excluded from high energy line break consideration was provided in response to RAI 21 of this letter. Provided below is a discussion of the exclusions that were made in accordance with the criteria provided in "a" above.

The Auxiliary Steam System is a high energy system that is normally in service. High energy boundaries were established at normally closed valves AS-7, AS-311, (1)(2)(3) AS-34, (1)(2)(3)AS-40, (1)(2)(3)AS-26, 1AS-465, AS-22, 3AS-22, and 3AS-364. A number of these valves (AS-26, AS-465, AS-22, and AS-364) are manually operated valves that are normally closed with no planned actions to open them. AS-7 and AS-311 are also manually operated valves that are normally closed, but they are opened whenever the Auxiliary Boiler is placed into service. AS-34 is a motor-operated valve that is normally closed, but it would be opened during a unit startup or shutdown to provide steam to the 'E' Feedwater Heaters to maintain sufficient feedwater temperatures. AS-40 is also a motor-operated valve that is normally closed, but the valve is opened during startup and shutdown to supply steam to the condenser steam air ejectors (CSAEs) to maintain condenser vacuum. The use of "short periods of time" was not applied to these normally isolated lines.

The Condensate System is a high energy system that is normally in service. High energy boundaries were established at normally closed valves (1)(2)(3)C-425, (1)(2)(3)C-426, (1)(2)(3)C-427, (1)(2)(3)C-124, (1)(2)(3)C-98, (1)(2)(3)C-99, (1)(2)(3)C-311, (1)(2)(3)C-314, (1)(2)(3)C-320, and (1)(2)(3)C-321. A number of these valves (C-98, C-99, C-320 and C-321) are manually operated valves that are normally closed with no planned actions to open them. The condensate booster pump (CBP) minimum recirculation valves (C-425, C-426, and C-427) automatically open (on the operating pump) when the total condensate flow decreases to 4500 gpm or below. The feedwater seal injection pump inlet valves (C-311 and C-314) are normally in automatic. The valves will automatically open when the associated seal injection pump receives a start signal due to low differential pressure between the CBP discharge pressure and the main feedwater pump suction pressure. The condensate recirculation path to the Upper Surge Tank (UST) is normally isolated by a closed motor-operated valve (C-124). The valve may be opened during unit startup or shutdown. The use of "short periods of time" was not applied to these normally isolated lines.

The Main Feedwater System is a high energy system that is normally in service. High energy boundaries were established at normally closed valves (1)(2)(3)FDW-53, (1)(2)(3)FDW-65, (1)(2)(3)FDW-38, (1)(2)(3)FDW-47, (1)(2)(3)FDW-74, (1)(2)(3)FDW-76, (1)(2)(3)FDW-200, (1)(2)(3)FDW-262, (1)(2)(3)FDW-263, (1)(2)FDW-279, (1)(2)(3)FDW-280, (1)(2)(3)FDW-283. A number of these valves (FDW-262, FDW-263, FDW-279, FDW-280, and FDW-283) are manually operated valves that are normally closed. The valves may be opened when draining the feedwater system. The main feedwater pump minimum recirculation valves (FDW-53 and FDW-65) are normally in automatic. While in the automatic mode, the valves throttle open when the applicable main feedwater pump suction flow decreases to about 2300 gpm. These valves may be operated in the manual mode during startup and shutdown evolutions to maintain total condensate flow within a prescribed flow band. The main feedwater cleanup line is normally isolated from the main feedwater system by closed motor-operated valves (FDW-74, FDW-76, and FDW-200). The valves may be opened during unit startup and shutdown when feedwater cleanup is desired. Each main feedwater header is equipped with a line that directs flow to the auxiliary nozzles of the associated steam generator. Each of these lines are normally isolated from the high energy portion of the main feedwater system by a closed motor-operated valve (FDW-38 and FDW-47). The valves are equipped with an automatic signal to open the valves on a loss of all four reactor coolant pumps or a loss of both main feedwater pumps. In addition, the valves may be opened during startup and shutdown evolutions. The use of "short periods of time" was not applied to these normally isolated lines.

The High Pressure Injection (HPI) System is a high energy system that is normally in service. High energy boundaries were established at normally closed valves (1)(2)(3)HP-116 and

(1)(2)(3)HP-409. The normally isolated portion of the HPI system can either be pressurized during certain accident conditions or for routine performance testing. The details of the historical review that was performed to quantify the "short periods of time" while subjected to high energy conditions is provided in the response to RAI 14 of this letter

The Main Steam System is a high energy system that is normally in service. High energy boundaries were established at normally closed valves (1)(2)(3)MS-153, (1)(2)(3)MS-155, (1)(2)(3)MS-19, (1)(2)(3)MS-22, (1)(2)(3)MS-28, (1)(2)(3)MS-31, (1)(2)(3)MS-37, and (1)(2)(3)MS-38. A number of these valves (MS-153, MS-155, MS-37, and MS-38) are manually operated valves that are normally closed. The atmospheric dump block valves (MS-153 and MS-155) may be opened for testing during startup or shutdown. In addition, the valves may be opened following events where the turbine bypass valves are not available. There are four turbine bypass valves (MS-19, MS-22, MS-28, and MS-31) that are normally closed. The discharge of each turbine bypass valve is connected to a common discharge header. The common discharge header is then divided into three lines that are directed to the main condenser (one line per condenser). During normal operation, these lines are subjected to vacuum conditions. Following a main turbine trip or planned shutdown of the main turbine, the turbine bypass valves (TBVs) open as necessary to control main steam pressure at the desired setpoint. The TBVs are utilized to cool the Reactor Coolant System (RCS) down to LPI entry conditions. During startup evolutions, the TBVs are initially opened to pull a vacuum on the steam generators. Once RCS heatup is commenced, the TBVs would be closed to allow the heatup to continue. The TBVs may be throttled open during periods of startup where the heatup process is placed on hold. The TBVs are also throttled open during reactor power increases until the main turbine is placed on -line. The use of "short periods of time" was not applied to these normally isolated lines. However, statements were made in sections 4.1.8, 5.1.8, and 6.1.8 of ONDS-351 that describe the downstream piping from the TBVs as not being pressurized more than 2% of the operating time of the main steam system. These statements will be corrected.

The Moisture Separator Reheater Drain (MSRD) System is a high energy system that is normally in service. High energy boundaries were established at normally closed valves (1)(2)(3)HD-25, (1)(2)(3)HD-26, (1)(2)(3)HD-27, (1)(2)(3)HD-28, (1)(2)(3)HD-29, (1)(2)(3)HD-30, (1)(2)(3)HD-102, (1)(2)(3)HD-103, (1)(2)(3)HD-41, (1)(2)(3)HD-43, (1)(2)(3)HD-56, (1)(2)(3)HD-58, 3HD-70, 3HD-72, 3HD-85, 3HD-87, 3HD-453, 3HD-454, 3HD-541, and 3HD-540. A number of these valves (HD-41, HD-43, HD-56, HD-58, 3HD-70, 3HD-72, 3HD-85, 3HD-87, 3HD-453, 3HD-454, 3HD-541, and 3HD-540) are manually operated valves that are normally closed. Drain valves (3HD-453, 3HD-454, 3HD-540, and 3HD-541) may be opened to drain the system. HD-102 and HD-103 are motor-operated valves that are normally closed. The second stage reheater (SSRH) drain tank dump valves (HD-25 and HD-26) are normally closed at full power. The valves will open when the main turbine is shutdown or if the normal level control valves (HD-92 and HD-95) are not capable of maintaining proper water level. The first stage reheater (FSRH) drain tank dump valves (HD-29 and HD-30) are normally closed at full power. The valves will open when the main turbine is shutdown or if the normal level control valves (HD-66 and HD-81) are not capable of maintaining proper water level. The moisture separator reheater (MSRH) drain tank dump valves (HD-27 and HD-28) may be throttled open at full power, depending on the mode of operation selected. If the MSRH drain tanks are being fed forward, then the dump valves would be closed. However, the dump valves discharge to the condenser hotwell, which is normally under vacuum conditions. In fact, all of the dump valves discharge to the condenser hotwell. The use of "short periods of time" was not applied to these normally isolated lines.

The Plant Heating System is a high energy system that is normally in service. High energy boundaries were established at normally closed valves (1)(2)(3)AS-182, (1)(2)(3)AS-70, (1)(2)(3)AS-75, (1)(2)(3)AS-73, (1)(2)(3)AS-78, 2AS-108, and PH-123. All of these valves are manually operated. Only AS-182 is repositioned by procedure. This valve is opened on the applicable unit when it is desired to place the Reactor Building Purge system in service and the outside air temperature is below 60°F. The applicable unit is below Mode 4 when this alignment occurs. The use of "short periods of time" was not applied to these normally isolated lines.

The Low Pressure Injection (LPI) System does not normally operate in a high energy condition. This system is normally isolated from the RCS by closed motor-operated valves. The system is charged from the BWST by two normally open motor-operated valves. The system is normally pressurized by the head of the BWST. Both the pressure from the BWST and the temperature in the system are below the threshold for high energy conditions. The LPI pumps are routinely tested during power operation. The testing does not subject the LPI system piping to high energy conditions. During the latter stages of plant cooldown, the system is isolated from the BWST and aligned to the RCS by opening the normally closed motor-operated valves from the RCS. The RCS is aligned to the LPI system after RCS pressure has been reduced to below 300 psig and RCS temperature has been reduced below 246 degrees F. This subjects the LPI system to high energy conditions until the RCS is cooled to 200 degrees F (or below) and depressurized to 275 psig (or below). Likewise, during the initial stages of RCS heatup and pressurization for unit startup activities, the LPI system is aligned to the RCS where conditions subject the LPI system to high energy conditions. The total time the LPI spends in high energy conditions is typically short in duration. A historical review was performed for startup/shutdown evolutions on all three units using OAC data to quantify the "short periods of time" while subjected to high energy conditions. The historical review period for Unit 1 was from 7/8/1999 to 6/1/2008. The historical review period for Unit 2 was from 12/16/1999 to 12/12/2008. The historical review period for Unit 3 was from 5/21/2000 to 12/18/2007. The LPI system experienced high energy conditions for approximately 32 [24 hour] days on Unit 1, approximately 17 days on Unit 2, and approximately 14 days on Unit 3 for the time period reviewed

The Reactor Building Spray, Emergency Feedwater, and the Standby Shutdown Facility Auxiliary Service Water systems are not normally in operation. These systems are either operated during certain accident conditions or for routine performance testing. The details of the historical review that was performed to quantify the "short periods of time" while subjected to high energy conditions is provided in the response to RAI 14 of this letter.

The Steam Generator Blowdown System is not normally in service. Each steam generator is equipped with a blowdown line that directs flow to the main condenser. Both of the blowdown lines are normally isolated from the high energy portion of the steam generators by closed manually operated valves located inside the reactor building. During unit startup, it is desired to establish steam generator blowdown to control the water chemistry inside the steam generators. The total time the steam generator blowdown piping spends in high energy conditions is typically short in duration. A historical review was performed for startup and shutdown evolutions on all three units using OAC data to quantify the "short periods of time" while subjected to high energy conditions. The historical review period for Unit 1 was from 7/8/1999 to 6/1/2008. The historical review period for Unit 2 was from 12/16/1999 to 12/12/2008. The historical review period for Unit 3 was from 5/21/2000 to 12/18/2007.The SG Hot Blowdown piping experienced high energy conditions for approximately 35 days on Unit 1, approximately 32 days on Unit 2, and approximately 35 days on Unit 3 for the time period reviewed.

RAI 24 [H]

In the response to RAI 14, in the HELB report, the licensee states "the subject piping....is seismically designed, analyzed, and supported... to assure that the Class G/F boundary is seismically protected." Please provide references to the appropriate calculations and evaluations or assessments that demonstrate the validity of the statements that are made.

Duke Energy Response

The piping stress analysis of the Main Feedwater system is contained in the following calculations OSC-336 (Unit 1), OSC-454 (Unit 2), and OSC-512 (Unit 3). These calculations document the seismically designed 'overlap boundaries' that extend beyond the Class G/F boundary.

RAI 25 [T/H]

In RAI 15, the NRC staff requested a list of all the equipment types (including manufacturer and model number) that need to be qualified for the environmental conditions of the LAR, with confirmation that all the identified components are qualified in accordance with Title 10 of the *Code of Federal Regulations* (10 CFR), Part 50, Section 50.49.

The licensee's response included a tabulated list with a statement referring to the list:

All of the above components existed prior to the LAR and that none of these components needed to be added to the Equipment Qualification program as a result of the LAR. All PSW [Protected Service Water] System components will be qualified for the applicable environment. None of the above listed components were replaced as a result of the LAR. The temperature and pressure profile for components located inside the [East Penetration Room] EPR [and] & [West Penetration Room] WPR was changed as a result of a new analysis for the postulated breaks on the main steam piping and main feedwater piping located inside the East Penetration Room. The above components were reviewed for the new pressure and temperature profiles and found to be qualified. The component evaluations are documented in calculation [Oconee site calculation] OSC-8505 [Oconee Nuclear Design Study] (ONDS-351, Revision 2, Ref. 10.2.17).

Define what the protected service water (PSW) components are and state when and how the PSW system components will be qualified for the applicable environment.

Duke Energy Response

A list of the engineered components for the Protected Service Water System (PSW) is provided below and type of environment (Harsh/Mild or N/A) as defined by Duke Nuclear System Directive NSD-303 (Environmental Qualification Program) and the Oconee Environmental Qualification Criteria Manual. A Mild or N/A designation indicates the component does not fall within the scope of 10CFR50.49.

The following is a summary of the processes used to ensure that the PSW system components will be qualified for the applicable environment.

The PSW engineered components are procured using Duke Engineering Directives Manual EDM-140 (Procurement Specifications For Equipment). The procurement documents are in the form of a Procurement Specification or a Technical Requirements Document (TRD).

A Procurement Specification is a controlled document that defines the requirements for the procurement of the equipment. A TRD is a "mini-specification" that provides the key technical and administrative information necessary to communicate the requirements to the equipment supplier.

Both the Procurement Specification and TRD contain equipment functional requirements for normal system operating conditions including temperature, pressure, flows, voltage, current, frequency, etc., seismic loads and for accident environmental conditions including temperature, pressure, humidity and radiation.

For equipment requiring Environmental Qualification (EQ), the procurement documents contain the performance requirements and qualification criteria and environmental parameters. The supplier submits a Qualification Test Plan which is reviewed by Duke to ensure that the proposed plan meets or exceeds the equipment specifications. Upon completion of the environmental testing, the supplier submits a Qualification Test Report which is processed in accordance with NSD-303.

If applicable, the equipment is identified as EQ-related in the Equipment Database (EDB) and included in the EQ Maintenance Manual (EQMM). The EDB identifies the EQMM section and qualified life for the equipment. The EQMM contains the information needed for maintaining the equipment environmental qualification including maintenance and replacement requirements.

PSW Component	Environment Type
PSW Primary Pump	Mild
PSW Booster Pump	Mild
PSW Building QA-1 HVAC System	Mild
Auxiliary Building PSW Pump Room Safety-Related Ventilation System	Mild
Motor Operated Throttle Valve (DMV-1710) for HP-31 Bypass Line	Harsh
Motor Operated Throttle Valves (DMV-1464 and DMV-1471)	Harsh
Modulating Solenoid Operated Throttle Valves (DMV-1463)	Mild (Modulation and Position Equipment) Harsh (Valve and Operator)
15 and 45 KVA QA-1 600/208/120 VAC Transformers	Mild
QA-1 Medium Voltage Unit Substation and Manual Disconnect Switch	Mild
QA-1 600 VAC Load Center and 5 MVA Transformer)	Mild
QA-1 125 VDC Distribution Center and Power Distribution Panels	Mild
QA-1 600 VAC Motor Control Centers	Mild
QA-1 208/120 VAC Power Distribution Panels	Mild
QA-1 200 HP Booster Pump Motor	Mild
QA-1 2000 HP Primary Pump Motor	Mild
QA-1 125 VDC Batteries	Mild
QA-1 125 VDC Battery Chargers	Mild
QA-1 5 kV Motor Operated Manual Transfer Switches for HPI Pumps	Harsh
QA-1 5 kV Manual Disconnect/Alignment Switches for HPI Pumps	Harsh
QA-1 600 VAC Manual Transfer Switches	Mild
QA-1 600 VAC Automatic Transfer Switches	Mild
QA-1 600 and 120 VAC Manual Transfer Switches	Mild
Keowee QA-1 Medium Voltage Switchgear, Protective Relay Board and Non-QA-1 Electrical Support Equipment	Mild

PSW Component	Environment Type
Keowee Isolated Bus Junction Box	Mild
Non-Safety PSW Building Air Conditioning Equipment	N/A
Isolation Relay Panels	Mild
Motor Operated Valve DMV-1711- HP-31 Outlet Isolation Valve.	Harsh
Handwheel Valve DHV-1455 - PSW Test Line Isolation Valve	N/A
Chainwheel PSW Isolation Valves DHV-1459 and DHV-1488	N/A
Motor Operated Valve DMV-1462 SG Common Header Isolation Valve	Harsh
Check Valves DMV-1472 and DMV-1483	N/A
Chainwheel Isolation Valve DMV-1473	N/A
Chainwheel Isolation Valve DMV-1478	N/A
Chainwheel Isolation Valves DMV-1484, DMV-1485 and DMV-1486	N/A
Handwheel Test Valve DMV-1487	N/A
Handwheel Valve DMV-1456 Auxiliary Service Water Suction Valve	N/A
Bargraph Indicators for 1HPI P-0025, 2HPI P-0152 and 3HPI P-0152	Mild
SBM Switches for 1RC CS-155/156, 2RC CS-155/156, 3RC CS-155/156, 1RC CS-157/158, 2RC CS-157/158, 3RC CS-157/158, 1RC CS-159/160, 2RC CS 159/160, 3RC CS-159/160, 1HPI CS-0024, 2HPI CS-0024, 3HPI CS-0024, 1HPI CS-0026, 2HPI CS-0026, 3HPI CS-0026, 1HPI CS-PUA, 2HPI CS-PUA, 3HPI CS-PUA, 1HPI CS-PUB, 2HPI CS-PUB, 3HPI CS-PUB, 1HPI CS-PUMP, 2HPI CS-PUMP, 3HPI CS-PUMP, 0PSW CS-0001, 0PSW CS-0002 and 0PSW CS-0003	Mild
SBM Switches and ET-16 Indicating lights for 1PSW CS-1X1, 1PSW CS-1XK, 2PSW CS-2XH, 2PSW-2XI, 2PSW CS-2XK, 3PSW CS-3XH, 3PSW CS-3XI, 3PSW CS-3XK, 1PSW LI 1XIG, 1PSW LI-1XIGI, 1PSW LI-1XIR, 1PSW LI-1XIR1, 1PSW LI-1XKG, 1PSW LI-1XKG1, 1PSW LI-1XKR, 1PSW LI-1XKR1, 2PSW LI-2XHG, 2PSW LI-2XHG1, 2PSW LI-2XHR, 2SPW LI-2XHR1, 2PSW LI-2XG, 2PSW LI-2XIG1, 2PSW LI-2XIR, 2PSW LI-2XIR1, 2PSW LI-2XKG, 2PSW LI-2XKG1, 2PSW LI-2XKR, 2PSW LI-2XKR1, 3PSW LI-3XHG, 3PSW LI-3XHG1, 3PSW LI-3XHR, 3PSW LI-3XHR1, 3PSW LI-3XIG, 3PSW LI-3XIG1, 3PSW LI-3XIR, 3PSW LI-3XIR1, 3PSW LI-3XKG, 3PSW LI-3XKG1, 3PSW LI-3XKR and 3PSW LI-3XKR1	Mild
PSW Building Fire Detection System	N/A
PSW Remote Motor Starter for SSF Submersible Pump	Mild

RAI 26 [H]

a) Please provide the calculations discussed in the response for review: OSC-8505 (ONDS-351, Revision 2, Reference 10.2.17), and OSC-8104 (ONDS-351, Revision 2, Reference 10.2.3).

b) Also, in the response to RAI 16, the licensee states that: "For postulated HELBs in other areas of the Auxiliary Building, equipment qualification is not required. Either the loss of any shutdown components in these areas would not preclude achieving and maintaining a safe shutdown condition, or adverse environmental conditions are not generated...."

Please provide reference to the documentation that forms the basis of this evaluation and conclusion.

Duke Energy Response

a.) The current revisions of both calculations, OSC-8104 & OSC-8505, have been electronically scanned and uploaded to the SharePoint site for NRC Staff review.

b.) The results of the interaction analyses of the postulated HELBs in the Auxiliary Building of each Oconee Nuclear Station are documented in Sections 4.2.1 (Unit 1), 5.2.1 (Unit 2), and 6.2.1 (Unit 3) of the Oconee HELB Report (ONDS-351). These evaluations are based upon the determination of the High Energy piping and break locations documented in calculations OSC-7516.01, Unit 1 (ONDS-351 Reference 10.2.2); OSC-7517.01, Unit 2 (ONDS-351, Reference 10.2.39); and OSC-7518.01, Unit 3 (ONDS-351 Reference 10.2.52). These HELB locations are listed in the respective Tables 4.1, 5.1, & 6.1 in the HELB Report. The plant equipment required for attainment and maintenance of the Safe Shutdown condition and subsequent unit cool down to the Cold Shutdown Condition are documented in calculations OSC-8089.01 & OSC-8089.02 (ONDS-351 References 10.2.4 & 10.2.15, respectively). All direct HELB interactions in any unit are documented in the respective Tables 4.2, 5.2 & 6.2 of the HELB Report. The indirect HELB interactions are described in the interaction analyses results in the HELB Report. The statement generated for RAI 26 is the overall summary statement for those areas of the Auxiliary Buildings beyond the East and West Penetration rooms, based upon the described interaction analyses in the HELB Report.

RAI 27 [T/H]

In RAI 17, the licensee states, "The primary and backup cables associated with the 125 vdc vital [instrumentation and control] I&C system will be rerouted out of the Turbine Building to eliminate vulnerabilities to HELB and/or Tornado events."

Please provide a reference to the documentation that validates this statement. Note that there is no commitment to reroute the cables in the commitments listed in the HELB report in the Unit 3 LAR.

Duke Energy Response

The rerouting of the primary and backup cables associated with 125 VDC Vital I&C System for each ONS Unit is part of the Protected Service Water (PSW) System modification for the Oconee Nuclear Station. The rerouting of these cables out of the Turbine Building is documented as one of the physical configuration changes for the PSW System in the Engineering Change Request for the PSW System.

Because these cable reroutes are contained within the PSW System modification scope and would be required in order to meet the PSW design criteria, a separate commitment is not necessary. Moreover, the description of the cable reroute modification on Page 9-3 of the HELB Report (ONDS-351, Rev.2) identifies this modification as part of the PSW project, which is a commitment. This modification was added to Section 9.0 of the HELB Report as a separate item in order to emphasize its importance for future reference.

RAI 28 [H]

a) It is not clear how the response to RAI 18 confirms that appropriate drainage is provided for all junction boxes. How were the holes sized?

b) Please provide details of, or reference to, an inspection plan or a controlled document that specifies the frequency of weep hole inspections.

c) Please address whether it is possible that the weep holes could provide a pathway for water to enter the enclosures?

Duke Energy Response

a) The outside-containment Viking electrical penetration enclosures will have three (3) 1/4 inch diameter weep holes located at the left, center and right of the bottom of the enclosure. The weep hole sizing and location were determined using Duke procedural guidance and engineering judgment based on the Viking enclosure design.

b) Inspection of electrical penetrations enclosure weep holes is included in procedure IP/0/A/3010/011 (Inspection of Electrical Penetration Enclosures). This procedure (including weep hole inspection) is performed on a six year frequency under an ONS model Work Order.

c) Due to evidence of past penetration room roof leaks resulting in water entry into the Viking enclosures, the weep holes were installed as an enhancement to the Viking electrical penetration enclosure design. The decision to install the weep holes is also consistent with guidance found in USNRC Information Notice 89-63. The Viking enclosures are not environmentally sealed. Postulated water entry through the weep holes is not a concern since the normal and accident conditions for the penetration rooms does not include spray or submergence.

RAI 29 [H]

The licensee's response to RAI 19 does not address RAI 19, as it does not discuss how the licensee ensured that failure of nonsafety-related components would not adversely affect the safety function of a safety-related component under postulated environmental conditions. Please address this issue.

Duke Energy Response

The Environmental Qualification (EQ) Program for the Oconee Nuclear Station (ONS) is governed by Duke Energy's Nuclear System Directive 303 (NSD-303), which is referenced in Section 3.11, Environmental Design of Mechanical and Electrical Equipment, of the ONS UFSAR.

NSD-303 identifies which electrical components are within the scope of 10CFR 50.49 and require environmental qualification. For non safety-related electrical equipment the directive requires environmental qualification of:

"Non QA Condition 1 (non safety-related) electrical equipment located in a postulated harsh environment, whose failure could prevent a safety function or mislead the plant operator."

Section 303.2.4, Evaluating Non-Safety Equipment, of NSD-303 provides additional guidance for determining if non safety-related components require EQ.

The method used by Oconee for identification of non safety-related electric equipment, whose failure under postulated environmental conditions could prevent satisfactory accomplishment of safety functions or mislead the operator is as follows:

1. A list was generated of safety-related electrical equipment as defined in paragraph (b)(1) of 10CFR 50.49 that are required to remain functional during or following design-basis Loss of Coolant Accident (LOCA) or High Energy Line Break (HELB) Accidents. The LOCA/HELB accidents are the only accidents that result in significantly adverse environments to electrical equipment, which is required for safe shutdown or accident mitigation. The list was based on reviews of the ONS, Units 1, 2, and 3 UFSAR and the elementary diagrams, connection diagrams, P&ID's (flow diagrams), and cable lists.
2. The elementary wiring diagrams of the safety-related electrical equipment identified in Step 1 are reviewed to identify any (non safety-related) auxiliary devices electrically connected directly into the control circuitry or power circuitry of the safety-related equipment, whose failure due to postulated environmental conditions could prevent the required operation of the safety-related equipment; and
3. In reviewing the environmental qualification documentation for class 1E equipment, the function of the equipment is reviewed via P&IDs, component technical manuals, and/or systems in the UFSAR. Any directly connected mechanical auxiliary systems to electrical equipment, which are necessary for the safety-related electrical equipment to perform its safety function are considered in the qualification of the class 1E equipment.
4. Non safety-related electrical circuits indirectly associated with the safety-related electrical equipment identified in Step 1 by common power supply or physical proximity are considered by a review of the ONS electrical design including the use of applicable industry standards (e. g. IEEE) and the use of properly coordinated relays, contacts, isolation amplifiers, individual output relays, circuit breakers, and fuses for electrical fault protection.
5. For those identified non safety-related components in a harsh environment that could adversely affect safety-related components or misled the plant operator identified in Steps 2-4, environmental qualification criteria are established, and the EQ of the component is documented per the requirements of NSD-303.

This methodology has been approved for ONS by NRC letter dated March 20, 1985. This letter has been uploaded to the SharePoint site.

RAI 30 [H]

In the response to RAI 21, the licensee states:

The postulated HELBs in the Auxiliary Building do not directly or indirectly impact any of the remaining components or their support systems. Cables for these components that are routed through the East or West Penetration Rooms are qualified for the adverse environmental conditions in these rooms, created by these postulated Main Feedwater or Main Steam line HELBs. The qualification of the cables is documented in calculation OSC-8505 (ONDS-351, Rev. 2, Ref. 10.2.17).

The NRC staff requests a copy of calculation OSC-8505 for review.

Duke Energy Response

The calculation has been electronically scanned and uploaded to the SharePoint site for Staff review.

RAI 31 [H]

NUREG 0800, Section 3.6.2, Item I (OL) 4, Revision 1, and NUREG 0800, Section 3.6.2, Item 1.7, Revision 2, identify as a specific area of review:

The design adequacy of systems, components, and component supports to ensure that the intended design functions will not be impaired to an unacceptable level of integrity or operability as a result of pipe-whip or jet impingement loadings.

In order to cover this area of review adequately, the following calculations are requested for review:

1. Calculation OSC-7516.01, "ONS Unit 1 HELB High Energy Line Break Stress Evaluation" (Application of criteria used to define break and crack locations and configurations).
2. OSC-7516.03, "Unit I HELB Turbine Building Structural Interactions Evaluations" (Application of methodology used to define the forcing functions, including the jet thrust reaction at the postulated pipe break or crack location and jet impingement loadings on adjacent safety-related, structures, systems and components (SSCs).
3. Calculation OSC-7516.04, "Safe Shutdown Equipment Damage Assessment for HELB -ONS Unit 1" (Application of criteria used to define break and crack locations and configurations).
4. OSC-8505, "Oconee HELB EO Analysis for Penetration Rooms" (Application of methods used to validate the equipment qualification of the Shutdown Electrical Components).

Duke Energy Response

The current licensing basis for the Oconee Station for High Energy Line Breaks is the Giambusso/ Schwencer letters. Oconee is not licensed to the Standard Review Plan (SRP) 3.6.2 and does not propose to be licensed as such in the future.

In order to fully evaluate the Oconee High Energy Line Break program per the statement quoted above the following calculations are required to be reviewed:

- OSC-7516.01
- OSC-7516.02
- OSC-7516.03
- OSC-7516.04
- OSC-8556
- OSC-7516.07
- OSC-7516.08
- OSC-7516.09
- OSC-7516.10

The purpose of each of these calculations is provided on Pages 1-2 to 1-4 & 1-9 of the HELB Report. All of these calculations are available in PDF form except for OSC-7516.03. Calculation OSC-8505 is also available in PDF form. All of the calculations except for OSC-7516.03 have been electronically scanned and uploaded to the SharePoint site for NRC Staff review.

In order to fully examine most of these calculations, review from the hard copies of them is strongly recommended. Examination of these calculations on the computer network is often awkward in orientation, the resolution of the drawings is not, in general, acceptable for review, and OSC-7516.03 could not be scanned. All of these calculations are readily available at the Oconee site and can be made immediately available for NRC review.

RAI 32 [H]

The HELB report in the Unit 3 LAR refers to ONS "HELB Outside Containment Walkdown Criteria & Requirements," (Reference 10.3.17). Please provide the document for review.

Duke Energy Response

Revision 3 of the "HELB Outside Containment Walkdown Criteria & Requirements" has been electronically scanned and uploaded to the SharePoint site for NRC Staff review.

RAI 33 [H]

Section 2.1 of the HELB report in the Unit 3 LAR states that:

> *The High Energy (Piping) lines are those lines that during Initial Operating Conditions the fluid inside of the pipe has either or both of the following conditions:*
>
> 1. *A normal operating temperature greater than 200 °F.*
> 2. *A normal operating pressure greater than 275 psig [pounds per square inch gage].*

According to the NUREG-0800 definition, a piping system with either a 200 of service temperature or a 275 psig design pressure would be considered high energy piping, while under the definition in the Unit 3 LAR they would not. Is there any piping that was eliminated from the high energy piping population because it had an exact 200 of service temperature?

Duke Energy Response

A review of the piping systems evaluated in calculation OSC-8385 (HELB Report Reference 10.2.1) showed that no piping has been eliminated from the high energy piping population based only upon its operating temperature, and there is no piping listed in the calculation as operating at 200°F. Moreover, all piping in the calculation with documented operating temperatures above 200°F is classified as high energy. The high energy piping determinations made beyond this calculation did not use the temperature criterion to eliminate piping from the high energy piping population.

RAI 34 [H]

Section 2.2.2 of the HELB report in the Unit 3 LAR states the following:

> *For branch connections to piping runs, a branch, appropriately modeled in a rigorous stress analysis with run flexibility and applied branch line movements included and where the branch connection stress is accurately known, will use the stress criteria for seismically analyzed piping lines; for postulating HELB locations.*

Do the "applied branch line movements" include amplified seismic response of the run piping at the branch line termination? If not, please address how "stress is accurately known" at that location?

Duke Energy Response

The applied branch line movements include both thermal and amplified seismic movements from the run pipe. The intersection of the run and branch line is represented as an anchor point in the branch line piping analysis model. The run pipe movements are applied as anchor motion(s) to the branch line piping analysis model.

RAI 35 [H]

The HELB report in the Unit 3 LAR states:

2.2.3 High Energy Break Type Criteria

The following criteria are used to identify the [high energy] HE break types, required to be postulated at the identified break locations in the ONS. There are three (3) types of HELBs at the ONS. These include circumferential breaks, longitudinal breaks, and critical cracks. The definition and description of each of these break types are provided in Section 1.5. The criteria for each break type are as follows (References 10.1.1, 10.1.3, & 10.3.17)[1]:

1. Circumferential Breaks are to be postulated in HE lines that exceed 1 inch in nominal pipe size.
2. Longitudinal Breaks are to be postulated in HE piping that has a nominal pipe size of four (4) inches or greater.
3. Critical Cracks are to be postulated on seismically analyzed HE piping that exceeds 1 inch in nominal pipe size (See Section 2.2.2 for exceptions).
4. HELBs of any type are not postulated on HE piping that has a nominal pipe of 1 inch or less.
5. Only circumferential breaks are to be postulated at terminal ends of HE piping runs. (Longitudinal breaks are not postulated at terminal ends.)
6. Longitudinal breaks are to be postulated only at intermediate break locations on HE piping runs.
7. For piping that has a nominal pipe size of four (4) inches or greater both circumferential and longitudinal breaks are to be postulated at the intermediate break locations but not concurrently.
8. Longitudinal breaks are to be postulated parallel to the pipe axis and orientated at any point on the pipe circumference.
9. The break area of a longitudinal break is equal to the effective cross-sectional flow area of the pipe immediately upstream of the break location.
10. Longitudinal breaks are not required to be postulated at branch connections.

Criterion 1 states that circumferential breaks are to be postulated in HE lines that exceed 1 inch in nominal pipe size. This concurs with 3.(b) of BTP ASB 3-1 (Appendix B of SRP 3.6.1, Revision 1, July 1981).

Provide documentation that the cited stress range condition is not exceeded in any lines that are 1 inch or smaller nominal pipe size.

Criterion 2 states that longitudinal breaks are to be postulated in HE piping that has a nominal pipe size of four (4) inches or greater. This concurs with 3.(a) of BTP ASB 3-1 (Appendix B of SRP 3.6.1, Revision 1, July 1981). Provide documentation that the cited stress range condition is not exceeded in any lines that are smaller than 4 inches nominal pipe size.

For Criterion 3, please explain the significance of postulating critical cracks on "seismically analyzed" HE piping that exceeds 1 inch in nominal pipe size. Please address the difference between seismically analyzed piping versus piping analyzed for all necessary load cases.

Criterion 10 states longitudinal breaks are not required to be postulated at branch connections. The

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[1] Note that bullets are used in the original text. Numbers are used here for clear reference below.

criterion appears to assume that branch connections are synonymous with terminal ends.

Provide the bases where, the branch runs are not classified as part of a main run in the stress analysis, that the branch runs does not have a significant effect on the main run behavior.

Duke Energy Response

Response to questions regarding ONDS-351, Section 2.2.3(1) and (2): The Giambusso/Schwencer criteria specifies in (3) "The criteria used to determine the pipe break orientation at the break locations as specified under (2) above should be equivalent to the following:

(a) Longitudinal breaks in piping in runs and branch runs, 4 inches nominal pipe size and larger, and/or
(b) Circumferential breaks in piping runs and branch runs exceeding 1 inch nominal pipe size."

BTP ASB 3-1 (Appendix B or SRP 3.6.1 Revision 1) sections 3(a) and 3(b) regarding stress ranges apply to Class 1 piping. There is no Class 1 piping outside containment at Oconee Nuclear Station. Since the ONDS evaluates the high energy line breaks outside containment, this provision of BTP ASB 3-1 does not apply.

Response to question regarding ONDS Section 2.2.3(3): Critical cracks were only postulated on rigorously analyzed piping that included seismic loading. There is no distinction between seismically analyzed piping versus piping analyzed for all necessary load cases. By definition, safety related equivalent Class 2 & 3 piping is analyzed for all necessary load cases at Oconee Nuclear Station. Section 2.2.2 of ONDS-351 addresses the applicable load cases for seismically analyzed piping. The fifth bullet item under Section 2.2.2 notes that for piping that is seismically analyzed the applicable load cases include internal pressure, dead weight (gravity), thermal, and seismic (OBE). Water-hammer load cases, as they applied to specific systems, were also included. The term, "seismically analyzed piping" was made to distinguish such piping from other piping systems at Oconee Nuclear Station that are analyzed, but are not analyzed for seismic loading. There are high energy piping systems at Oconee Nuclear Station that are rigorously analyzed for internal pressure, dead weight (gravity) and thermal, but not for seismic loading.

Response to question regarding ONDS Section 2.2.3(10): The intent of this criterion is that longitudinal breaks were not postulated for the branch pipe part of the branch connection. If the branch run piping was not classified as part of the main run in the stress analysis (e.g. the branch run was analyzed in a separate model), an anchor was assumed at the intersection of the branch run and main run. Anchor movements from the run piping were applied to the branch piping. A terminal end was assumed at the anchor location and a full circumferential break was postulated at the terminal end. The postulation of a circumferential break at the terminal end is equivalent to a longitudinal break of the run piping. For further discussion on analysis methodology of branch piping, see the response to RAI 18.

RAI 36 [T/H]

Section 3.4 of the HELB report in the Unit 3 LAR provides design criteria for the main steam isolation valves (MSIVs) to be installed. Are these valves to be designed to close against a flow resulting from an HELB immediately downstream?

Duke Energy Response

The planned modification to install the MSIVs includes a design requirement to close against the flow resulting from the postulated HELBs in the main steam line downstream of the MSIVs. Although the MSIVs have not yet been purchased, the procurement specification for the MSIVs has been released to vendors for quotes. The specification requires the valves to be capable of closing on demand when MS pressure reaches the closing setpoint (approximately 550 psig main steam pressure) with a flow rate corresponding to a double-ended break in the 36-inch (34-inch inside diameter) main steam line inside the turbine building. The flow rate specified for automatic closure is approximately 20,000,000 lbm/hr.

RAI 37 [T/H]

Provide the following information for the installation of the MSIVs.

1. Valve functional design, drawing, and specifications
2. Qualification program for demonstrating that the MSIV is capable of performing its specified functions under design basis conditions.
3. In-service testing program for monitoring and ensuring that the MSIV is capable of performing its functions under specified conditions.
4. Qualification test report.

Duke Energy Response

(1)(2)(3)(4) A procurement specification for the MSIVs (OSS-0245.00-00-0019) was developed and vendors have provided bids which are currently undergoing technical/commercial evaluation. The MSIV vendor has not yet been selected. The MSIV procurement specification has been posted on the SharePoint site (placed in the HELB RAI response documents folder). The valve drawings, qualification plans, in-service testing and qualification tests will not be available until the valve manufacturer has been selected and the procurement process started.

RAI 38 [T/H]

Describe the inadvertent closure of Main Steam Isolation Valves (MSIVs) and the affect on the plant.

Duke Energy Response

The planned modification to install the MSIVs includes performing the safety analysis for an inadvertent closure of a MSIV. The final design of the MSIVs and the associated calculations have not been completed.

RAI 39 [T/H]

For the operator actions associated with tornado and HELB mitigation provide the following information:

1. What is the required training?
2. How often will the training occur?
3. Will simulator training be used?

Duke Energy Response

Operators will receive initial classroom and simulator training on the Protected Service Water (PSW) modifications and the associated procedures that will be used by the operators to place the system(s) in service.

The simulator will be modified as part of the plant modifications so that it reflects the as-built condition in the plant for the systems that are controlled from the main control room.

The classroom and simulator training will be incorporated into the operator requalification training program. The frequency of the requalification training has not been established. The frequency of the operator training is determined by using the systematic approach to training (SAT) as described in the Employee Training and Qualification System (ETQS) Standards. The frequency of the training is based on a number of factors such as importance, difficulty, and how often the operators would be expected to operate the system in an emergency. Based on the results of the training analysis, the frequency of requalification could be every 2 years or every 4 years.

RAI 40 [T/H]

Provide the following information for the tornado and HELB restoration procedures:

1. How will the restoration procedures be laid out?
2. Will the procedures be symptom-based such that it would be able to be used for any tornado or HELB?
3. When will they be completed and implemented.

Duke Energy Response

The "restoration procedures" referred to in the RAI are those procedures that would be used to assess damage to plant equipment and the associated repair actions that may be necessary due to a tornado or a postulated HELB inside the Turbine Building that requires the use of the PSW or SSF system for the establishment and maintenance of safe shutdown.

Damage assessment and repair procedures were initially created for managing the damage caused by an Appendix R fire scenario where the SSF was relied upon for the establishment and maintenance of safe shutdown. However, these procedures would be utilized to determine the extent of damage resulting from a tornado or a postulated HELB in the Turbine Building and to direct repair efforts to restore needed functions. These procedures are coordinated in that an initial damage assessment is performed to determine the capability of restoring electrical power and plant systems needed to support a plant cooldown. Once the extent of damage has been identified, damage repair procedures are initiated to either restore that equipment or provide an alternate means of providing the system function.

These procedures are not symptom based. However, the damage assessment procedure is a systematic approach to determining the status of systems needed for plant cooldown. Therefore, the actions would be taken regardless of the event causing the damage.

The existing damage assessment procedure does not specifically check for piping integrity. Procedure enhancements are planned to improve the damage assessment to identify any breaches of HPI, LPI, CCW, and LPSW (essential headers) so that they can either be isolated or repaired prior to placing the systems in service. This has been entered into Oconee's corrective action program.

RAI 41 [T/H]

In the licensee's October 23, 2009, supplement the licensee refers to agreements with the NRC staff on a number of different issues concerning tornado/HELB mitigation strategies. The NRC staff notes that that these agreements have not been submitted to the NRC in accordance with 10 CFR 50.4. Please provide the documentation in accordance with 10 CFR 50.4.

Duke Energy Response

In the 2006-2007 timeframe, a number of pre-submittal meetings were conducted in support of planned tornado and HELB LAR submittals. Common understanding of the approaches to be used in the submittals was achieved for the issues anticipated. The common understandings achieved were compiled in a Tornado, HELB, or Common Item matrix and docketed (ADAMS acquisition number ML70670203).

The NRC items used in these matrices were a compilation of past NRC tornado and HELB issues taken from a number of past communications between Duke Energy and the Staff that were being discussed in pre-submittal meetings in order to develop a common understanding of the licensing approaches to be included in the tornado and HELB license amendment requests. The information discussed in these meetings was not intended to be used for regulatory decision making relative to Oconee's license. As a result, each matrix was tagged with "Draft Document - For Discussion Purposes Only" in the footer of each page and placed on the docket as attachments to the NRC meeting summaries.

Based on the age of the information and the nature of the previous correspondence, Duke Energy is not able to complete internal processes to validate the completeness and accuracy of the information presented in the matrices. Where a common understanding was achieved that resulted in an agreement to provide additional information in a license amendment request, the matrices have been updated to indicate the location of Duke Energy's position regarding the matter in the tornado and/or HELB license amendment requests that were submitted in accordance with 10 CFR 50.4. The Attachment to this submittal contains the updated matrices.

RAI 42 [T/H]

Describe how the PSW system will be isolated from other safety systems and/or will not cause unintended results should a PSW system active or passive failure occur. Include information for both the electrical and mechanical system associated with the PSW installation.

Duke Energy Response

The PSW System is a backup system utilized following postulated HELB or Tornado events, when safety systems, located in the Turbine Building, are not available to support a safe shutdown of the Oconee Units. The PSW system is divided into a mechanical portion and an electrical portion. A discussion of each of these parts of the PSW System follows:

Mechanical Portion

The mechanical portion of the PSW System consists of the PSW Booster Pump, the PSW Primary Pump, the associated valves, piping, instrumentation, the PSW Pump Room Exhaust Fan, and the PSW Building HVAC System. The mechanical portion of the PSW System is isolated both physically and functionally from other safety systems. The PSW Booster Pump, the PSW Primary Pump, the pump suction & discharge piping, and the associated vales & instrumentation for the pumps are located in the PSW Pump Room. This room is physically isolated from other equipment in the Unit 2 Auxiliary Building. The only mechanical PSW equipment located in the Auxiliary Building beyond the PSW Pump Room are the piping lines to each unit's Emergency Feedwater (EFW) System, the piping lines to the Low Pressure Service Water (LPSW) piping, and the PSW Pump room Exhaust Fan. The PSW System pump suction line interfaces with the Unit 2 Condenser Circulating Water (CCW) System. The PSW Building HVAC System is located within the PSW Building. The PSW System is functionally isolated from the EFW and LPSW Systems by at least one closed valve. The suction line for the PSW Pumps from the CCW System has a normally open isolation valve.

The PSW System components in the Auxiliary Building are maintained in a standby condition with no equipment operating. Since the PSW System is not in operation and no mechanical movement of any component is required to maintain the standby condition, no single active failures (See "Single Active Failure" definition Page 1-16 of the ONS HELB Report, ONDS-351) can be created. This condition of no mechanical movement also applies to the electrical power and control circuits for the pumps and valves, and thus, creates no single active failures. If the PSW System is manually actuated, then the EFW and/or the LPSW Systems are not available to support the safe shutdown of the Oconee units, and any single active failure of the PSW System could not adversely affect either of these systems. Also, because of the physical and functional isolation and the standby mode status of the PSW System, there are no passive failures of the PSW System that could adversely affect either of these systems. In order to provide an assured water source the PSW Pumps suction line is required to be open to support operation of the PSW Pumps. The design of the PSW Pumps suction piping and connection to the CCW pipe has been made based upon the need to have the PSW Pumps suction line non-isolated from the CCW System.

The PSW Building HVAC System is in continuous operation. However, the PSW Building is physically remote from the other areas of the ONS. As such, any single active failure or passive failure of the PSW Building HVAC System could not adversely affect any other safety system of any Oconee Unit.

Electrical Portion

The major on-site electrical components of the PSW system are located in the PSW building, the Auxiliary Building, the Keowee Hydro Station and the Standby Shutdown Facility (SSF) and are summarized as follows:

In the PSW building, the major PSW electrical components consists of medium voltage switchgear which is composed of two 10 MVA 13.8/4.16 kV transformers and 13.8 and 4.16 kV breakers, a 600 VAC load center with a 5 MVA 4160/600 VAC transformer, a 600 VAC motor control center, a 600 VAC manual transfer switch, a SSF submersible pump starter, two 125 VDC station batteries, two battery chargers, one 125 VDC distribution center, 125 VDC panelboards and associated miscellaneous electrical support equipment including a 600/208/120 VAC transformer, 208/120 VAC panelboards, lighting, receptacles, a HVAC system and a fire detection system.

In the Auxiliary Building, the major PSW electrical components consists of 600 VAC motor control centers, 600 VAC pressurizer heater manual transfer switches, 4.16 kV manual alignment switches and motor operated HPI pump motor transfer switches, 600 VAC automatic transfer switches for the Vital I&C normal battery chargers, 600/208/120 VAC transformers, 208/120 VAC panelboards, 125 VDC panelboards and associated local and main control room instrumentation and controls

At the Keowee Hydro Station, the major PSW electrical components consist of 13.8 kV switchgear, junction boxes for connecting to the existing 13.8 kV buss and associated Keowee and main control room instrumentation and controls.

At the SSF, the major PSW electrical components consist of a 4.16 kV switchgear cubicle and associated SSF control room instrumentation and controls.

The main electrical connections to existing safety systems are the HPI pump motor power feeds, the Vital I&C normal battery chargers, the pressurizer heaters (a non-QA-1 electrical system), Keowee 13. 8 kV power and SSF 4.16 kV power.

Electrical isolation from existing safety systems is provided by transfer switches, breakers and/or fuses. A Failure Modes and Effects Analysis/Single Failure Analysis (FMEA/SFA) will be performed for the PSW electrical system. The FMEA/SFA will evaluate the PSW electrical system as a whole and the interfaces with existing systems including HPI pump motor power, normal Vital I&C battery charger input power, pressurizer heater power and the Keowee and SSF power systems.

The FMEA/SFA is performed as part of the Engineering Change process in accordance with EDM-105 (Guidelines for Performing a Failure Mode and Effects Analysis and Single Failure Analysis). The FMEA evaluates the PSW design requirements related to redundancy, failure detection systems, fail-safe characteristics, and automatic and manual override. The SFA (if required) is performed similar to the FMEA but that the failure modes are a function of licensing basis requirements.

RAI 43 [T/H]

Provide the following information for the new protected service water (PSW) system transformer, switchgear, load center and the circuit breakers: (1) equipment design ratings, (2) a summary of the analyses performed to show the loading, short circuit values and the interrupting ratings, voltage drop, and protection and coordination, (3) the existing station ASW switchgear ratings, and (4) the periodic inspection and testing requirements for electrical equipment. Provide applicable schematic and single line diagrams.

Duke Energy Response

Please refer to response for RAI 2-27 contained in Duke Energy RAI submittal dated August 31, 2010 (Ref. 5).

RAI 44 [T/H]

Provide the following information concerning the proposed PSW instrumentation and control (I&C) power and the interface with the existing plant vital I&C power: (1) design of the direct current (DC) system for the PSW system including how the DC control power for the new PSW load center, switchgear and the transformer will be provided, (2) the impact on existing DC vital system including loading on the existing battery and the battery charger, (3) describe the analysis performed to determine the capacity of the batteries and the battery charger, voltage requirements at the equipment terminals, electrical protection and co-ordination, and (4) the periodic inspection and testing requirements. Provide applicable schematic and single line diagrams.

Duke Energy Response

Please refer to response for RAI 2-28 contained in Duke Energy RAI submittal dated August 31, 2010 (Ref. 5).

RAI 45 [T/H]

The Keowee Hydroelectric Units (KHUs) will provide power supply to the PSW switchgear through underground cables. Provide analyses to show the kilo volt ampere (kVA) loading, new circuit breaker rating, short circuit values, and voltage drop. In addition, provide information on the electrical protection and coordination, and the periodic inspection and testing requirements. Further, explain how the redundancy and independence of the Class 1E power system is maintained as a result of the proposed modification. Provide applicable schematic and single line diagrams.

Duke Energy Response

Please refer to response for RAI 2-29 contained in Duke Energy RAI submittal dated August 31, 2010 (Ref. 5).

RAI 46 [T/H]

The PSW system will be fully operational from the respective unit's main control room and will be activated when existing redundant emergency systems are not available. Describe how the alarms, indications, and the electrical controls will be provided from the main control rooms of Units 1 and 2 to the proposed PSW switchgear. Explain how the controls are provided for Unit 3. Provide applicable electrical schematics and evaluations highlighting the design features.

Duke Energy Response

Please refer to response for RAI 2-30 contained in Duke Energy RAI submittal dated August 31, 2010 (Ref. 5).

RAI 47 [T/H]

Provide information on how the licensing basis for physical independence and separation criteria are met for the PSW electrical system.

Duke Energy Response

Please refer to response for RAI 2-31 contained in Duke Energy RAI submittal dated June 24, 2010 (Ref. 6).

RAI 48 [T/H]

The new PSW system switchgear will receive power from the KHUs via a tornado-protected underground feeder path. Provide the following information:

1. Type of underground cable installation, i.e., direct burial or in duct banks, manholes etc.
2. How the licensee will ensure that the proposed new underground cables remain in an environment that they are qualified for
3. Periodic inspections and testing planned for cables to monitor their performance, and
4. Details regarding cable size, type, maximum loading requirements, and cable protection devices.

Duke Energy Response

Please refer to response for RAI 2-32 contained in Duke Energy RAI submittal dated August 31, 2010 (Ref. 5).

RAI 49 [T/H]

Provide information concerning the design details for the new 100/13.8 kV substation, the PSW transformer and switchgear building power feeds, its protection, controls and alarms features. Provide applicable single line diagram and electrical schematics.

Duke Energy Response

Please refer to response for RAI 2-33 contained in Duke Energy RAI submittal dated August 31, 2010 (Ref. 5).

RAI 50 [T/H]

Two new power feeds will be installed to the auxiliary building (AB) with one power supply to the Units 1, 2, and 3 AB equipment high-pressure injection (HPI) pumps and vital I&C normal battery chargers and other power supply to the backup power to the Units 1, 2, and 3 pressurizer heaters. Provide the following information concerning this installation: (1) compare and contrast the existing power supply requirements for the above loads, (2) how the electrical separation, independence, and redundancy requirements are maintained, (3) summary of the voltage analyses for the equipment/components affected by this modification, (4) design details for the new power feeds to AB, (5) periodic inspections and testing schedule for the these cables to monitor their performance, and (6) *provide the electrical schematics and one-line drawings for these power feeds.*

Duke Energy Response

Please refer to response for RAI 2-34 contained in Duke Energy RAI submittal dated August 31, 2010 (Ref. 5).

RAI 51 [T/H]

Provide confirmation that the maximum float/equalizing voltage does not exceed the equipment maximum dc voltage rating.

Duke Energy Response

Please refer to response for RAI 2-35 contained in Duke Energy RAI submittal dated June 24, 2010 (Ref. 6).

RAI 52 [T/H]

Describe in detail how the 125 vdc vital I&C primary and backup power cables and the KHU emergency start circuitry will be rerouted from the turbine building to the auxiliary building.

Duke Energy Response

Please refer to response for RAI 2-36 contained in Duke Energy RAI submittal dated August 31, 2010 (Ref. 5).

RAI 53 [T/H]

To ensure licensing-basis clarity and component operability, Technical Specifications (TSs) need to properly address the tornado mitigation systems (e.g., PSW/SSF, protected service water/ standby shutdown facility, etc.) in a manner that is consistent with the Standard TS requirements that have been established for the functions that are being performed by these systems. For example, the minimum required mission time should be 7 days and the Completion Times should be limited to 72 hours in most cases for the SSF and the PSW including maintenance. Justify the existing limiting condition for operation (LCO) time for the SSF in the current TSs and the proposed LCO for the PSW system based on the fact the proposed tornado mitigation strategy relies solely on the SSF and the repair of the PSW system to achieve and maintain hot standby and entry into cold shutdown following a design basis tornado/HELB. The proposed TS change for the PSW system and the existing SSF does not preclude both diverse systems being out of service concurrently please provide a justification for this.

Duke Energy Response

For tornado response please refer to RAI response letter dated August 31, 2010 (Ref. 5).

HELB Background

As ONS construction was nearing completion, the Atomic Energy Commission (AEC) issued a letter from A. Giambusso (AEC), Deputy Director for Reactor Projects Directorate of Licensing, to Duke Power Company (now Duke Energy Carolinas, LLC (Duke Energy), dated December 15, 1972[2]. The "Giambusso Letter" required licensees to address the consequences of pipe ruptures outside containment and submit their analyses to the AEC for review. Due to the specific guidance in the letter, the applicable events were identified as "High Energy Line Break" (HELB) events. The "Giambusso Letter" was amended by an errata sheet provided in a letter from A. Schwencer (AEC), Chief Pressurized Water Reactors Branch No. 4 Directorate of Licensing, to Duke Power Company, dated January 17, 1973[3] (the "Schwencer letter").

Duke Energy's evaluations of postulated pipe ruptures outside containment were documented in MDS Report No. OS-73.2 dated April 25, 1973, with Supplement 1 to the report dated June 22, 1973 and Supplement 2 to the report dated March 12, 1974. The final report is referred to herein as "current HELB report," "MDS Report" and/or "OS-73.2."

The MDS report was incorporated into the ONS license application by reference. It was subsequently approved and accepted by the AEC. "Safety Evaluation prepared by the Directorate of Licensing related to the Oconee Nuclear Station, Units 2 and 3," (referred to herein as "the SER") dated July 6, 1973[4], was issued as part of the initial licensing of Units 2 and 3. SER Section 7.1.11 "High-energy Line Rupture External to the Reactor Building" addressed the MDS report, and Attachment E of the SER repeated the NRC HELB criteria, as amended by the Schwencer letter. The following is extracted from Section 7.1.11:

"The basic criteria require that:

(1) Protection be provided for equipment necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming a concurrent and unrelated single active failure of protected equipment, from all effects resulting from ruptures in pipes carrying high-energy fluid, up to and including a double-ended rupture of such pipes, where the temperature and pressure conditions of

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[2] Letter dated 15 December 1972 from A. Giambusso (AEC) to A. C. Thies (DPC) transmitting the "General Information Required for Consideration of the Effects of a Piping system Break Outside Containment."

[3] Clarification Letter (related to the 15 December 1972 letter), dated 17 January 1973, from A. Schwencer (AEC) to A. C. Thies (DPC)

[4] Safety Evaluation Report (From AEC) for Oconee Units 2 & 3, July 6, 1973.

the fluid exceed 200 °F and 275 psig. Breaks should be assumed to occur in those locations specified in the "pipe whip criteria." The rupture effects on equipment to be considered include pipe whip, structural (including the effects of jet impingement) and environmental.

(2) Protection be provided for equipment necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming a concurrent and unrelated single active failure of protected equipment, from the environmental and structural effects (including the effects of jet impingement) resulting from a single open crack at the most adverse location in pipes carrying high-energy fluid routed in the vicinity of this equipment, where the temperature and pressure conditions of the fluid exceed 200 °F and 275 psig. The size of the cracks should be assumed to be l/2 the pipe diameter in length and l/2 the wall thickness in width....

Staff Evaluation and Conclusion

The staff has evaluated the assessment performed by the applicant and has concluded that the applicant has analyzed the facilities in a manner consistent with the intent of the criteria and guidelines provided by the staff. The staff agrees with the applicant's selection of pipe failure locations and concludes that all required accident situations have been addressed appropriately by the applicant.

Furthermore the staff has evaluated the analytical methods and assumptions used in the applicant's analyses and find them acceptable and concurs with the proposed plant modifications and the criteria to be used in their designs."

Several years after approval of the MDS report and initial licensing of ONS, the SSF was constructed. The SSF provides additional defense-in-depth protection to achieve and maintain Mode 3 with an average Reactor Coolant System temperature ≥ 525 °F following postulated fire, sabotage, or internal flooding events.

The SSF Reactor Coolant Make-up (RCMU) system is the SSF sub-system designed and credited to supply Reactor Coolant Pump seal injection flow in the event that the High Pressure Injection (HPI), the normal make up system, becomes inoperable when a Unit's RCS temperature is > 250 °F. It can recover RCS volume shrinkage caused by cooling the RCS to Mode 3 with an average Reactor Coolant temperature ≥ 525 °F. However, the SSF Reactor Coolant Make-up System is not credited for events, such as LOCA, which result in significant loss of RCS inventory. The SSF Auxiliary Service Water System (ASW) is the SSF sub-system credited as the backup to the Feedwater (FDW) and Emergency Feedwater (EFW) systems.

A 1998 Duke HELB self-assessment revealed issues with the original OS-73.2 report, and as a result, Duke decided to fully revalidate and revise the HELB CLB. In late 1999, Duke initiated a project to determine scope of these CLB revision efforts[5]. This HELB CLB revision effort was completed on a unit by unit basis with the final license amendment request submitted to the Staff in June 2009.

The updated HELB mitigation strategy addresses the measures to be taken to minimize postulated pipe failures that could affect structures, systems, and components (SSC) necessary to achieve and maintain a Safe Shutdown condition. SSCs located in the TB are protected from postulated breaks and cracks that could occur in the AB due to separation. In addition, SSCs located in the AB are protected from postulated breaks and cracks that could occur in the TB. SSC's located in the Standby Shutdown Facility (SSF) are protected from breaks that could occur in the TB. SSF related systems and components located in the WPR have been evaluated for pipe ruptures postulated to occur in the WPR.

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[5] Letter from W. R. McCollum, Jr., Vice President, Oconee Nuclear Station, to the Nuclear Regulatory Commission, "High-Energy Line Break outside Reactor Building Methodology," dated July 3, 2002.

Technical Specification discussion

The SSF and the PSW systems do not mitigate design basis accidents (DBAs). Consequently, neither SSF nor PSW operability requirements readily fit into the standardization process established by NUREG 1430 [Standard Technical Specifications for Babcock and Wilcox Plants], i.e., the document does not contain any criteria for a protected service water system. The system in the NUREG with the closest fit is EFW, however, EFW requirements are tied to the mitigation of DBAs.

The existing limiting conditions for operation (LCOs) for the SSF systems and the proposed LCOs for the PSW systems are justified based on the overall risk improvement that is achieved by the installation of the PSW system. The current ONS tornado licensing basis relies on redundant and diverse secondary side decay heat removal (SSDHR) sources and primarily on the tornado-protected SSF Auxiliary Service Water system for acceptability. In order to simplify the licensing basis, the requested tornado licensing amendment credits only the SSF for mitigation of tornado-related damage to the station. The redundancy and diversity of SSDHR sources remains unchanged and is in fact improved by the addition of the PSW system. The availability of the redundant, diverse SSDHR sources (including PSW) are (or will be) in the station's PRA. As a result, the SSF system's risk worth is expected to decrease with the completion of the PSW project. A decrease in risk worth of the SSF systems justifies the continued acceptability of the exiting SSF LCOs.

RAI 54 [T/H]

Provide a list of any new analyses, codes, and/or models being utilized for the proposed tornado/HELB mitigating strategies that need to be integrated into the UFSAR. Provide the justification for their use.

Duke Energy Response

For tornado response please refer to RAI response letter dated August 31, 2010 (Ref. 5).

The new analyses, codes and models utilized in evaluating the consequences of postulated HELBs outside containment are discussed in the HELB Report. The HELB Report will be included by reference to section 3.6.1 of the UFSAR. The new analyses, codes and models will not be included in Chapter 15 of the UFSAR.

A number of computer codes were utilized to evaluate the effects of HELBs. These include:

- RETRAN-3D was used to determine the plant response following a postulated letdown line break and a double main steam line break.
- RETRAN-02 was used to determine the plant response following a postulated main feedwater line break
- SIMULATE-3P was used to determine if a return-to-power condition resulted following a postulated double main steam line break
- CASMO-3 was used in conjunction with SIMULATE-3P.
- VIPRE-01 was used to determine the minimum DNBR following a postulated double main steam line break
- LOCADOSE was used to determine potential offsite and control room doses following a postulated letdown line break.
- Gothic 4.0 was used to calculate pressure and temperature response inside the penetration rooms following a main steam line break or main feedwater line break.

- Gothic 7.0 was used to calculate the pressure response in other enclosed areas of the auxiliary building with postulated breaks in the plant heating system.
- RT^3 was used to evaluate the temperature response of the control complex following a main steam line break in the penetration room.
- A model was developed for the Turbine Building to evaluate the effects of pipe whip on the structure using GT (Georgia Tech) STRUDL.

The use of computer codes RETRAN-3D, RETRAN-02, SIMULATE-3P, CASMO-3 and VIPRE-01 are described in Section 15.1.2 of the UFSAR.

LOCADOSE computer code has been previously used to determine offsite and control room doses for design basis events in Chapter 15 of the UFSAR.

The GOTHIC 4.0/DUKE computer code was first licensed for use in the Duke methodology report DPC-NE-3004-PA, "Mass and Energy Release and Containment Response Methodology" for Duke's McGuire / Catawba units in 1995. In this report, the use of the GOTHIC 4.0/DUKE code and models for pressure/temperature transient calculations within the ice condenser containments of McGuire and Catawba was justified. It has been used for many Duke licensing basis applications as described in Section 6.2 of the UFSARs for those plants. One recent application using this computer code is the License Amendment Request (LAR) to implement the Water Management initiative at Catawba and McGuire. An SER was received from the NRC for Catawba's Water Management LAR on June 28, 2010. The corresponding LAR for McGuire is still under review.

Other LARs in which the GOTHIC 4.0/DUKE code was applied have been submitted and approved since 1995. These include the changes to Tech Spec Surveillance Requirement (SR) 3.6.12.4 to allow asymmetric loading of the ice condenser baskets (lower allowable weights for inner rows), the elimination of the torque test on the ice condenser lower inlet doors from SR 3.6.13.6, and changes to allow the manual starting of the Containment Air Return Fans for certain Small Break LOCA scenarios. Again, these LARs were submitted for the McGuire/Catawba units.

GOTHIC 4.0/DUKE was the latest version of GOTHIC released by Numerical Applications Inc. (the code vendor) at the time the DPC-NE-3004 submittal was made. Several updated code releases have been released since then, with the most recent GOTHIC release being Version 7.2e. In September 2003, an SER was received for Revision 1 of the Duke Methodology Report DPC-NE-3003. *In this revision of Oconee's containment analysis methodology report,* the GOTHIC 7.0 code was approved for use "to calculate the reactor building response to high energy line breaks". The GOTHIC 7.0 code, which is a later version of GOTHIC 4.0/DUKE, was demonstrated to provide similar results to the FATHOMS/DUKE-RS code which had been Oconee's licensing basis containment analysis methodology since the original approval of DPC-NE-3003 in 1994.

The high energy line break response inside the penetration rooms described in Duke calculation OSC-8104 is a very similar calculation to the LOCA/SLB responses inside the Oconee Reactor Building addressed in DPC-NE-3003. The GOTHIC 4.0/DUKE code is expected to give similar answers to any similar analysis performed by GOTHIC 7.0, as there have been no major changes made to the GOTHIC code between those releases which would significantly impact the results of such an analysis.

Therefore, it is demonstrated that the GOTHIC 4.0/DUKE code is an acceptable method for calculating conditions within the Oconee penetration rooms following a high energy line break.

The RT^3 computer code is currently used to evaluate the temperature response of the control complex following a loss of ventilation. The same model was employed with a new heat load source from the penetration room due to the MSLB.

RAI 55 [T/H]

Provide the following information concerning the ability to achieve and maintain hot standby (TS MODE 3) following the worst-case design basis tornado/HELB.

a. List of equipment that will be used

b. Initial plant conditions.

c. Discuss any scenarios where with use of only the SSF/PSW to achieve and maintain hot standby would cause any of the units to operate outside the normal operating boundaries as described in the UFSAR (i.e., the RCS does not stay sub-cooled with a pressurizer steam bubble).

d. Provide the basis for the SSF/PSW initiation times and confirmation that human factors assessment has been completed that is consistent with the NRC review standards and guidance to validate operator actions and times.

e. Provide a list of all operator actions, a timeline for achieving hot standby and the systems that will be available and the amount time when other systems (SSF/PSW/HPI) will have to be repaired/restored to maintain the units in a safe and stable condition following a tornado/HELB.

Duke Energy Response

For tornado response please refer to RAI response letter dated August 31, 2010 (Ref. 5).

The "worst-case" HELBs are described in Section 7.0 of ONDS-351. Three classes of HELBs are described in this section. They include Main Steam Line Breaks (MSLB), Main Feedwater Line Breaks (FWLB) and a postulated line break in the Reactor Coolant letdown line. These events were analyzed since they would generate the most extreme transient conditions in the station. The list of equipment used to mitigate the consequences of these events is described for each event. The initial plant conditions are also described for each event.

There are HELB scenarios (i.e., MSLBs) where the RCS sub-cooling margin may be lost. These are also discussed in Section 7.0 of ONDS-351. These scenarios did not credit the SSF for event mitigation.

The bounding scenario for the SSF/PSW initiation times is a postulated FWLB inside the turbine building that results in a loss of main and emergency feedwater with a loss of all reactor coolant pump seal cooling. A source of feedwater to the steam generators must be re-established within 15 minutes. A source of reactor coolant pump seal cooling must be re-established within 20 minutes to avoid damaging the seals. These actions will ensure that RCS natural circulation flow is not interrupted due to excessive voiding in the RCS hot legs.

The SSF ASW system is capable of being aligned within 14 minutes. The initiation time for SSF ASW has been previously reviewed and approved by the NRC. The PSW system will be capable of being aligned within 15 minutes, once installed. Operator time validations are completed to confirm the capability as part of the modification process.

The SSF RC Make-Up System is capable of being aligned to provide seal injection flow within 20 minutes. The initiation time for the SSF RC Make-Up System has been previously reviewed and approved by the NRC. Seal injection flow from an HPI pump (powered from PSW) will be capable of being established within 20 minutes, once installed. Operator time validations are completed to confirm the capability as part of the modification process.

If the SSF is the only means available for establishing safe shutdown following a postulated HELB or tornado, then some equipment would need to be restored within 72 hours to maintain safe shutdown. The selection of equipment to restore would depend on the extent of damage resulting from the postulated HELB or tornado. Normal plant systems located inside the Turbine Building would be the preferred choice. However, if the extent of plant damage would preclude their recovery within 72 hours, the PSW mechanical and electrical systems would need to be restored.

If the PSW system is being utilized to maintain safe shutdown following a postulated HELB, there is no immediate need for plant cooldown. However, the PSW system is capable of supporting a plant cooldown to approximately 250°F. Operators would need to be dispatched to throttle the atmospheric dump valves to enable a plant cooldown. RCS inventory control and RCS pressure control could be maintained inside the main control room.

RAI 56 [T/H]

Discuss how cold shutdown will be achieved following a design basis tornado/HELB including, (a) define the actions necessary for achieving cold shutdown based on the worst-case repairs that will need to be made following a tornado/HELB; (b) recognition of the strategy/systems to be used (e.g., residual heat removal, PSW, SSF, LPI, HPI, pressurizer heaters, atmospheric dump valves, instruments, etc.) identification of specific vulnerabilities that need to be addressed, equipment to be staged (e.g., cable, motors, motor control centers, switchgear portable pumps etc.); and, (c) a human factors assessment of effort/repair that is consistent with the NRC review standards/guidance. Provide a time line and procedures for maintaining safe and stable conditions after entering into hot standby and an estimate for achieving cold shutdown. Provide the limitations of the SSF/PSW systems if these are the only systems used to achieve hot standby and maintain safe and stable conditions.

Duke Energy Response

For tornado response please refer to RAI response letter dated August 31, 2010 (Ref. 5).

A discussion is provided in ONDS-351 regarding achieving cold shutdown following postulated HELBs outside containment. There are three general areas where HELBs are postulated to occur. The first general area is inside the Auxiliary Building. The second general area is outside in the yard. The third general area is inside the Turbine Building. Postulated HELBs inside the Auxiliary Building or outside in the yard would not prevent the establishment of cold shutdown. However, some postulated HELBs inside the Turbine Building could result in damage to plant equipment where cold shutdown could not be established without damage repairs.

There are some postulated HELBs inside the Turbine Building where all 4160VAC power could be lost to each unit. For these postulated HELBs, either the PSW System or SSF are utilized to establish and maintain safe shutdown. The PSW system in conjunction with the atmospheric dump valves is capable of supporting a plant cooldown to approximately 250°F without damage repairs. However, power must be restored to the core flood tank outlet valves when RCS pressure is reduced to less than 800 psig to enable their closure. Damage repairs are necessary to restore CCW, LPSW and LPI to operation to enable RCS cooldown from approximately 250°F to cold shutdown. The CCW system is restored by repowering one CCW pump motor from an available 4160VAC power source, providing cooling water to the CCW pump motor, and opening two condenser waterbox outlet valves using bottled nitrogen if instrument air is not available. The LPSW system is restored by repowering one LPSW pump motor shared by Units 1 and 2, and one LPSW pump motor for Unit 3 from an available 4160VAC power source. The LPI system is restored by restoring 600VAC power to LP-1 and LP-2 (which are located inside the Reactor Building) in addition to repowering one LPI pump per unit from an available 4160VAC power source.

There are some postulated HELBs inside the Turbine Building where interactions with Condenser Circulating Water (CCW) and Low Pressure Service Water (LPSW) piping may result in flooding of the Turbine Building resulting in a total loss of emergency feedwater and low pressure service water. Additional damage repairs would be necessary to restore CCW and LPSW to operation. These repairs would include isolation of broken piping where possible, piping repair for breaks that cannot be isolated, and replacement of the LPSW pump motors due to flooding.

The equipment needed to repower the 4160VAC CCW pump and LPSW pump motors is stored onsite. Spare motors for the LPSW pumps are stored onsite. The equipment needed to repower the 600VAC core flood tank discharge valves and the LPI valves located inside containment is also stored onsite. The equipment needed for damage repair is located external to the Turbine Building and will be available following the postulated HELBs inside the Turbine Building.

Regarding human factor assessments for the damage assessments and repairs described above, the actions taken to restore vulnerable equipment needed for a unit cooldown to approximately 250°F would be accomplished utilizing station procedures. The preparation, review and approval of station procedures are performed in accordance with section 17.3.2.14 of the Duke QA Topical Report. The damage assessment and repair procedures are classified as permanent technical procedures that would be utilized after the plant has been brought to a safe shutdown condition using the existing emergency procedures. The purpose of the damage assessment procedures is to determine the availability of unprotected systems and components utilized during a plant cooldown. The repair procedures are employed to restore any damaged equipment discovered during the assessment. The assessment and repair procedures would be initiated after the Emergency Response Organization (ERO) has been staffed. A validation and verification process is in-place to address the adequacy of technical procedures. These procedures are designated as the following types:

- Emergency Response Procedures (RP)
- Operating Procedures (OP)
- Instrument and Electrical Procedures (IP)
- Mechanical Maintenance Procedures (MP)

The time line for maintaining safe shutdown conditions using the PSW or SSF system is described in section 3.1 of ONDS-351. The description and capabilities of the PSW and SSF systems are described in sections 3.2 and 3.3 of ONDS-351, respectively.

RAI 57 [T/H]

Describe what instrumentation will be available following the worst case tornado/HELB. Describe all instrument failures (e.g., pressurizer level, etc.) and how they will be discerned in support of main control room and/or SSF/PSW control.

Duke Energy Response

For tornado response please refer to RAI response letter dated August 31, 2010 (Ref. 5).

Section 3.10 of ONDS-351 provides a list of indications needed by the operator to establish and maintain safe shutdown. The list of instrumentation included instrumentation needed in the main control room and the SSF control room. The list was used as potential safe shutdown "targets" in the evaluation of postulated HELBs outside containment. The instrumentation remains available following the worst case HELBs outside containment. Power for the main control room instrumentation following the worst case HELB is provided by the applicable unit's control batteries via the PSW electrical system, while the SSF control room instrumentation is provided by the SSF electrical distribution system.

The available indications inside the main control room for maintaining safe shutdown include:

- RCS Pressure
- RCS Temperature (hot legs, cold legs, and core exit thermocouples)
- Pressurizer Water Level
- RCS Water Levels (Reactor Vessel and Hot Legs)
- RCS Subcooling Margin
- Neutron Flux
- Letdown Storage Tank Water Level
- Borated Water Storage Tank Water Level
- High Pressure Injection Flow
- RCP Seal Injection Total Flow
- Steam Generator Water Level
- Steam Generator Pressure
- Upper Surge Tank Level (used only with emergency feedwater operation)
- Emergency Feedwater Flow
- Protected Service Water Flow

The available indications inside the SSF control room for maintaining safe shutdown include:

- RCS Pressure
- RCS Temperature (hot legs and cold legs)
- Pressurizer Water Level
- RC Makeup Pump Pressures (suction and discharge)
- RC Makeup Pump Flow
- Steam Generator Water Levels
- SSF Auxiliary Service Water Flow (to each unit).

RAI 58 [T/H]

Discuss the how the RCP seals are protected following a tornado/HELB.

Duke Energy Response

For tornado response please refer to RAI response letter dated August 31, 2010 (Ref. 5).

RCP seal cooling is normally provided by the High Pressure Injection (HPI) and the Component Cooling (CC) systems. Either system is capable of providing adequate RCP seal cooling to protect the seals. The CC system is not a high energy system. Therefore, no HELBs are postulated in the CC system. The HPI system is a high energy system. The CC system is credited for providing RCP seal cooling following a postulated HELB in any of the HPI seal injection lines. There are no postulated HELBs inside the Auxiliary Building that would disable both the HPI and CC systems. However, there are postulated HELBs inside the Turbine Building that may result in the loss of both HPI and CC systems. For the postulated HELBs that result in the loss of both HPI and CC systems, the PSW system is credited for providing power to one HPI pump, HPI valves and instruments needed to support RCP seal injection. These power alignments can be made from the control room with RCP seal injection reestablished within 20 minutes. The PSW system and the associated power sources are protected from the effects of postulated HELBs inside the Turbine Building.

In addition to the PSW system, the SSF Reactor Coolant Makeup (RCMU) system is capable of providing RCP seal cooling by means of seal injection within 20 minutes after a loss of both HPI and CC systems due to postulated HELBs. The SSF RCMU system is protected from the effects of postulated HELBs inside the Turbine Building.

Since seal injection flow is established within 20 minutes after a loss of HPI seal injection and CC system flow, seal degradation or failure will not occur and flow rates associated with a seal loss of cooling accident (LOCA) will not occur.

The SSF RCMU system is the credited system for providing RCP seal cooling following tornado damage that result in the loss of both HPI and CC systems.

RAI 59 [T/H]

It has been noted by the NRC staff that the LARs for both tornado and HELB mitigation strategies contain information that appears not up to date (i.e. commitments, commitment dates, system designs, complete documentation, HELB report) Please review the LARs and all supplemental submittals and update the LARs as necessary.

Duke Energy Response

In an effort to expedite the HELB LAR submittal process it was decided that each unit would be evaluated and submitted separately until the HELB mitigation strategy report was completed for the entire station, i.e., the HELB report submitted as part of the third LAR installment not only included that unit but also enveloped the results of the other two units.

The Unit 1 HELB LAR was submitted in June 2008, followed by Unit 2 HELB LAR in December 2008, and finally the Unit 3 HELB LAR was submitted in June 2009.

The complete HELB licensing footprint is comprised of the following:

1. Unit 3 LAR containing the complete HELB Report (Rev. 2),
2. Unit 3 LAR technical specifications,
3. Unit 3 LAR UFSAR update,
4. Unit 3 LAR commitment table,
5. Unit 3 LAR tables and figures,
6. Unit 1 LAR commitment table
7. Unit 1 LAR tables and figures,
8. Unit 2 LAR commitment table,
9. Unit 2 LAR tables and figures,
10. Duke Energy submittal of supplemental information dated September 2, 2009,
11. Duke Energy RAI response dated October 23, 2009.

The complete Tornado licensing footprint is comprised of the following:

1. Tornado LAR dated June 26, 2008,
2. Tornado LAR UFSAR update,
3. Tornado LAR commitment table,
4. Duke Energy RAI response dated September 2, 2009,
5. Duke Energy RAI response dated May 6, 2010.
6. Duke Energy RAI response dated June 24, 2010,
7. Duke Energy RAI response dated August 31, 2010.

The following are the commitments associated with either the HELB (H) or Tornado (T) LARs.

Note: The sequential numbering of these commitments includes, but does not show, prior commitments made in Duke Energy's November 30, 2006 letter and subsequent update letters. From the lists below, commitments 18T and 19T were revised to coincide with the anticipated approval of the tornado mitigation strategy LAR. In addition, for both the tornado and HELB mitigation strategies, licensing actions associated with the incorporation of Fiber Reinforced Polymer and Main Steam Isolation Valves (MSIVs) for applicable events are or will be addressed by separate applications.

No.	UNIT 1 HIGH ENERGY LINE BREAK LAR COMMITMENTS – 26H THROUGH 33H	DUE DATE
26H	The inlet isolation valves to the Letdown Coolers on the Letdown Line (1HP-1 & 1HP-2) will be upgraded to permit their use following a postulated HELB on the Letdown Line at Containment Penetration No. 6. With these valves upgraded, either could then be closed if either of the inboard containment isolation valves (1HP-3 & 1HP-4) fails to close in order to mitigate the postulated HELB on the Letdown line.	To be provided to the Staff upon issuance of the SER.
27H	The ducting near the Control Complex is being upgraded with duct registers or cover plates to prevent the potential propagation of the HELB generated environment in the East Penetration Room to the Control Complex.	To be provided to the Staff upon issuance of the SER.
28H	The valves (1HP-103 & 1HP-107) on the individual suction lines to the "A" & "B" High Pressure Injection (HPI) pumps are being upgraded to allow the remote operation (operated outside the HPI pump room) of these valves. The remote operation of these valves allow the isolation of postulated HELBs on the discharge side of the HPI Pumps without compromising the availability of the other HPI Pumps and the need for maintaining the Letdown Storage Tank aligned to the HPI Pump suction piping. For a single active failure of either valve 1HP-103 or 1HP-107 to close, a redundant, remotely operated valve is provided on each of the HPI Pumps "A" and "B" to assure HELB mitigation.	To be provided to the Staff upon issuance of the SER.
29H	The position of several Plant Heating System isolation valves is being changed from "OPEN" to "CLOSED." This position change will eliminate the need to postulate Plant Heating System HELBs in the East Penetration Room and West Penetration Room, because these piping lines will be isolated during normal plant conditions of the station.	To be provided to the Staff upon issuance of the SER.
30H	Turbine Building structural support column D-26 will be modified by adding a brace to the column. This brace is necessary to prevent potential failure of the column, when subjected to a pipe whip load. This upgrade prevents the loss of the routing to get temporary cabling to the Low Pressure Injection and Low Pressure Service Water pump motors.	To be provided to the Staff upon issuance of the SER.
31H	The existing Condenser Circulating Water (CCW) discharge stop gates will be replaced and four (4) new stop gates will be obtained. These stop gates will be used to terminate all reverse flow through HELB damaged Low Pressure Service Water and CCW piping. This modification is required, in order to recover from a Turbine Building flood event caused by a postulated HELB therein.	To be provided to the Staff upon issuance of the SER.
32H	Evaluate the ability of the Standby Shutdown Facility to perform its safety functions with a compromised main steam pressure boundary due to potential breaks in the main steam system and other HELBs.	Complete.
33H	Weep holes will be installed in the bottom of the outside-containment junction box enclosures for the Viking Electrical Penetrations. Also, the electrical penetration inspection procedure is being amended to inspect the weep holes for blockage	Complete.

No.	UNIT 2 HIGH ENERGY LINE BREAK LAR COMMITMENTS – 34H THROUGH 39H	DUE DATE
34H	The inlet isolation valves to the Letdown Coolers on the Letdown Line (2HP-1& 2HP-2) will be upgraded to permit their use following a postulated HELB on the Letdown Line at Containment Penetration No. 6. With these valves upgraded, either could then be closed if either of the inboard containment isolation valves (2HP-3 & 2HP-4) fails to close in order to mitigate the postulated HELB on the Letdown line.	To be provided to the Staff upon issuance of the SER.
35H	The Unit 2 HVAC ducting near the Control Complex is being upgraded with duct registers or cover plates to prevent the potential propagation of the HELB generated environment in the East Penetration Room to the Control Complex.	To be provided to the Staff upon issuance of the SER.
36H	The valves (2HP-103 & 2HP-107) on the individual suction lines to the "A" & "B" High Pressure Injection (HPI) pumps are being upgraded to allow the remote operation (operated outside the HPI pump room) of these valves. The remote operation of these valves allow the isolation of postulated HELBs on the discharge side of the HPI pumps without compromising the availability of the other HPI Pumps and the need for maintain the Letdown Storage Tank aligned to the HPI Pump suction piping. For a single active failure of either valves 2HP-103 or 2HP-107 to close, a redundant, remotely operated valves is provided on each of the HPI Pumps "A" and "B" to assure HELB mitigation.	To be provided to the Staff upon issuance of the SER.
37H	The position of several Unit 2 Plant Heating System isolation valves is being changed from "OPEN" to "CLOSED." This position change will eliminate the need to postulate Plant Heating System HELBs in the East Penetration Room and West Penetration Room, because these piping lines will be isolated during normal plant conditions of the station.	To be provided to the Staff upon issuance of the SER.
38H	Turbine Building structural support Column D-29 & D-31 will be modified by adding a brace to the column. This brace is necessary to prevent potential failure of the column, when subjected to a pipe whip load.	To be provided to the Staff upon issuance of the SER.
39H	Weep holes will be installed in the bottom of the Unit 2 outside-containment junction box enclosures for the Viking Electrical Penetrations. Also, the electrical penetration inspection procedure is being amended to inspect the weep holes for blockage.	December 2011

No.	UNIT 3 HIGH ENERGY LINE BREAK LAR COMMITMENTS – 40H THROUGH 45H	DUE DATE
40H	The inlet isolation valves to the Letdown Coolers on the Letdown Line (3HP-1 and 3HP-2) will be upgraded to permit their use following a postulated HELB on the Letdown Line at Containment Penetration No. 6. With these valves upgraded, either could then be closed if either of the inboard containment isolation valves (3HP-3 and 3HP-4) fails to close in order to mitigate the postulated HELB on the Letdown Line.	To be provided to the Staff upon issuance of the SER.
41H	The Unit 3 Auxiliary Building HVAC ducting near the Unit 3 Control Complex is being upgraded with duct registers or cover plates to prevent the potential propagation of the HELB generated environment in the East Penetration Room to the Unit 3 Control Complex.	To be provided to the Staff upon issuance of the SER.
42H	The valves (3HP-103 and 3HP-107) on the individual suction lines to the "A" and "B" High Pressure Injection (HPI) pumps are being upgraded to allow the remote operation (operated outside the HPI pump room) of these valves. The remote operation of these valves allow the isolation of postulated HELBs on the discharge side of the HPI Pumps without compromising the availability of the other HPI Pumps and the need for maintaining the Letdown Storage Tank aligned to the HPI Pump suction piping. For a single active failure of either valve 3HP-103 or 3HP-107 to close, a redundant, remotely operated valve is provided on each of the HPI Pumps "A" and "B" to assure HELB mitigation.	To be provided to the Staff upon issuance of the SER.
43H	The position of the Unit 3 Plant Heating System isolation valve 3AS-182 being changed from "OPEN" to "CLOSED." This position change will eliminate the need to postulate Plant Heating System HELBs in the East Penetration Room and West Penetration Room, because these piping lines will be isolated during Normal Plant Conditions of the station.	To be provided to the Staff upon issuance of the SER.

No.	UNIT 3 HIGH ENERGY LINE BREAK LAR COMMITMENTS - 40H THROUGH 45H	DUE DATE
44H	Turbine Building structural support columns M-20 (Unit 1), M-35 (Unit 2), D-43 and D-45 (Unit 3), M-49 (Unit 3), and L-47 (Unit 3) will be modified by adding a brace or reinforcement to each column. These modifications are necessary to prevent potential failure of the column(s), when subjected to a pipe whip load.	To be provided to the Staff upon issuance of the SER.
45H	Weep holes will be installed in the bottom of the Unit 3 outside-containment junction box enclosures for the Viking Electrical Penetrations. Also, the electrical penetration inspection procedure is being amended to inspect the weep holes for blockage.	December 2011

No.	TORNADO LAR COMMITMENTS - 15T THROUGH 19T	DUE DATE
15T	Analyze the double column set which support each unit's Main Steam lines outside of the containment building, and provide modifications, as necessary, to meet tornado criteria	Complete
16T	Physically protect the Atmospheric Dump Valves (ADVs) per UFSAR Class 1 tornado criteria.	To be provided after completion of the SSF/MS line safety analysis
17T	Improve protection of the Standby Shutdown Facility (SSF) double doors (large 8'x12' doors located on the south side of the SSF structure) per UFSAR SSF tornado criteria.	12-2011
18T	Revise and clarify the tornado LB description as documented in UFSAR Section 3.2.2; add the TORMIS methodology results to UFSAR Section 3.5.1.3, and correct inaccurate tornado design information for the Auxiliary Building Cable and Electrical Equipment Rooms as described in UFSAR Table 3-23.	~~12-2010~~ 12-2011
19T	The SSF BASES for TS 3.10.1 will be clarified to address degradation of passive civil features as not applying to operability under Technical Specifications Limiting Condition for Operation (TS LCO) 3.10.1, "Standby Shutdown Facility," but rather as UFSAR commitments outside of the ONS TS.	~~12-2010~~ 12-2011

RAI 60 [T/H]

If the SSF or PWS systems are activated to mitigate a tornado or HELB what is the potential for accelerated corrosion of the steam generator tube which could lead to a steam generator tube rupture.

Duke Energy Response

If the SSF or PSW systems are activated to mitigate a tornado or HELB, lake water could be introduced to the steam generators. The use of lake water for these events does not constitute a change to the licensing basis for Oconee. In the original tornado and HELB analysis, the low pressure auxiliary service water system was the credited means of establishing feedwater to the steam generators. In addition, the low pressure auxiliary service water system was credited for long term decay heat removal following a loss of all external water sources. The PSW system is replacing the existing low pressure auxiliary service water system.

It is further noted that the steam generator tubes and key steam generator support structures (support plates, tie rods) are constructed of corrosion resistant materials. Specifically, the steam generator tubes are constructed of Alloy 690 material. The support plates and tie rods are constructed of stainless steel material.

The corrosion-resistant materials of construction of the steam generators should prevent accelerated corrosion of steam generator components that might result in tube rupture from such an event.

The following information includes a follow-up inquiry from the Staff after issuance of the October 8, 2010, RAI letter (denoted as an "RAI") in addition to proposed changes to the HELB and Tornado LARs by Duke Energy to correct inconsistencies in the original LAR submittals (denoted as an "Item").

RAI 61 [T]

In reference to the May 6, 2010, "Responses to Request for Additional Information for the License Amendment Request to Revise Portions of the Updated Final Safety Analysis Report Related to the Tornado Licensing Basis," additional clarification is requested. Please provide the basis for the following statements from the earlier responses:

Page 4, 4th paragraph

"There are several (described below) that affect assumptions in the TORMIS analysis."

Unclear what "assumptions" are being affected.

Page 9, 1st paragraph

"Significant damage is defined as damage that would prevent meeting a design basis safety function."

Page 9, 4th paragraph

"In some cases, multiple SSCs must be simultaneously damaged to be "important" and the TORMIS code can provided the probability of these simultaneous multiple strikes."

Page 10, 1st paragraph

Collectively, this list of items represents the frequency of damage to any individual SSC that could fail the Standby Shutdown Facility (SSF) mitigation strategy as described in the LAR.

Despite the reference to "multiple SSCs" on Page 9, 4th paragraph, it appears that only Tornado strikes on single SSCs whose failure would individually and directly prevent a design basis function are included in the evaluation. Please confirm whether this is accurate and discuss why multiple strikes are not considered.

Duke Energy Response

The response to RAI 2-2 (part b) in the May 6, 2010, letter discusses a set of plant modifications that Duke committed to implement to improve tornado missile protection. The physical location, dimensions, and material properties of plant structures and safety targets are key assumptions in the TORMIS analysis model. These modifications represent changes to the material properties of existing structures and new structures that have been incorporated in the TORMIS models. The installation of MSIVs provides an isolation function which eliminates main steam piping in the Turbine Building (downstream) from being considered as targets.

Situations in which multiple SSCs must be simultaneously damaged to affect the required plant safety function are addressed in Section 5.2 in Attachment 4 of the Oconee Tornado LAR. The specific cases that were identified were determined to have a negligible probability and were therefore omitted from the Table 5 results.

It is noted that the TORMIS code is capable of determining the probability of 2 targets at the same time but not 3 targets at the same time, and also will not estimate a damage probability of a target located below grade inside of a structure. These limitations affected the evaluation of two of the special cases. In the case of the "pedestal" columns, a sensitivity run was made for each unit (3 pairs of columns). The results of the sensitivity evaluations returned a zero probability of a simultaneous damaging strike on both columns.

Item 62 [T/H]

Duke Energy proposes to change the terminology "KHU underground path" given in several previously submitted TS, TSB, and UFSAR marked-up pages, to "KHU Protected Service Water Power Path." This change is being made to alleviate potential operator confusion since the pathway terminology used from the KHUs to the PSW switchgear building is not the same as the underground path from the KHUs to the CT4 blockhouse.

Duke Energy Action

The affected LAR pages affected are:

1. HELB LAR: PSW TS page 3.7.10-1
2. HELB LAR: PSW TS page 3.7.10-2 (SR 3.7.10.2)
3. HELB LAR: PSW TSB page B 3.7.10-4
4. Tornado LAR: Enclosure 2, page 9
5. Tornado LAR: Enclosure 2, page 14
6. Tornado LAR: Enclosure 2, page 23

These pages have been revised and the markups included in the Attachment to this submittal.

Item 63 [T]

The wording in the tornado LAR which states that all of the PSW ductbank is located underground requires revision. As such, Duke Energy proposes the following change:

Duke Energy Action

As stated in Enclosure 2 of the Tornado LAR [Ref. 7] beginning at the end of page 9 onto page10, *"As added margin, alternate power (primary power is from the KHU underground feed) to the new PSW System is provided from the Central Tie Switchyard via a 100 kV transmission line to a 100/13.8 kV substation located adjacent to the station and then via a 13.8 kV overhead path where it enters an underground ductbank leading to the PSW switchgear building."* This statement was factual at the time of Tornado LAR submission; however, as the design of the new ductbank has progressed, it has become necessary to locate limited portions of the ductbank above ground due to constructability and interference issues. The two areas where the new ductbank is above ground are where the new ductbank joins to the existing Keowee Underground Path and where the new ductbank crosses the Radwaste trench near the PSW building. The sections of the ductbank that are above ground have been designed to be tornado protected. Therefore, the entire PSW ductbank remains fully protected from tornado effects

Consequently, Duke Energy proposes to change the word "underground" to "tornado protected" in the quoted statement. The statement will now read, *"As added margin, alternate power (primary power is from the KHU underground feed) to the new PSW System is provided from the Central Tie Switchyard via a 100 kV transmission line to a 100/13.8 kV substation located adjacent to the station and then via a 13.8 kV overhead path where it enters a tornado protected ductbank leading to the PSW switchgear building."*

Attachment

Documentation for Responses to RAI 13, RAI 41, and Duke Energy Item 62

Response Documentation for:

RAI 13

Table RAI-13: Comparison of Oconee HELB Design Basis with BTP MEB 3-1 (Revision 2)

BTP MEB 3-1 Section	Description	Oconee Design	Comments/Clarifications
B.1.a	Separation of Essential Systems for Pipe Ruptures.	Conforms	Redundant Systems necessary to achieve safe shutdown are physically separated[1].
B.1.b (entire section)	Break and Crack Exclusion in Fluid Piping located in Containment Penetration Areas (between isolation valves).	Optional, not applicable	Terminal End Breaks in Containment Penetration Areas originally postulated in the 1973 MDS report will be retained. Exclusion of break or critical locations is not used. Breaks or critical cracks in high energy lines located in the Containment Penetration Areas are based on stress thresholds
B.1.c.(1) (entire section)	Postulation of Pipe Breaks in Class 1 Piping Outside of the Containment Penetration Area.	Not Applicable	There is no Class 1 Piping located outside containment.

[1] The overall mitigation strategy is predicated on separation of essential systems (e.g., those systems and components necessary to reach safe shutdown) from the postulated high energy line break. For breaks postulated to occur in the Turbine Building, systems and components located in the Auxiliary Building or the Standby Shutdown Facility (SSF) would be available for mitigation of the effects from the break. For breaks postulated to occur in the Auxiliary Building, systems and components located in the Turbine Building or SSF would be available for mitigation of the effects from the break.

Table RAI-13: Comparison of Oconee HELB Design Basis with BTP MEB 3-1 (Revision 2)

BTP MEB 3-1 Section	Description	Oconee Design	Comments/Clarifications
B.1.c.(2)(a)	Postulation of Pipe Breaks at Terminal Ends for ASME Class 2 or Class 3 piping Outside the Containment Penetration Area.	Partially Conforms	Terminal end breaks are not postulated at closed isolation valves separating a high energy system from a non high energy system, if the line containing the isolation valve is included in the stress analysis of the system and the stress analysis is continuous across the valves, such that valid stress information is available. Terminal end breaks are postulated at closed isolation valves separating a high energy system from a non high energy system for those cases when the system under consideration does not have a seismic stress analysis.
B.1.c.(2)(b)(i) **or** (ii)	For ASME Class 2 or 3 Piping: (i) Postulation of Intermediate Pipe Breaks at each pipe fitting **or** (ii) Postulation of Intermediate Pipe Breaks based on high stress.	Conforms	USAS B31.1. is the code of record for Oconee. Only SSF-Auxiliary Service Water piping meets classification as ASME Class 3 piping. SSF-ASW piping is classified as not operating during normal operations.

Table RAI-13: Comparison of Oconee HELB Design Basis with BTP MEB 3-1 (Revision 2)

BTP MEB 3-1 Section	Description	Oconee Design	Comments/Clarifications
B.1.c.(3)	Intermediate Pipe Breaks for Non ASME seismically analyzed piping.	Partially Conforms	For seismically analyzed piping, breaks to be postulated in high energy systems at locations were primary + secondary stress equals or exceeds .8 x (Sa + Sh), determined in accordance with USAS B31.1 (1967 Edition). For non analyzed piping or analyzed piping that does not contain seismic loading, pipe ruptures are postulated at all pipe girth welds.

Table RAI-13: Comparison of Oconee HELB Design Basis with BTP MEB 3-1 (Revision 2)

BTP MEB 3-1 Section	Description	Oconee Design	Comments/Clarifications
B.1.c.(4)	Design of structure(s) separating high energy lines from essential systems and components.	Conforms	Structure(s) separating high energy lines from essential systems and components are designed for the consequences of pipe break(s) as follows: For HELBs located in the Turbine Building, no pressurization loading is assumed on the structure due to numerous openings in the building, and the large open volume of the building that would prevent significant pressurization type loading. For HELBs located in the East Penetration Room of the Auxiliary Building, pressure relief features have been incorporated in the design of the building to prevent significant pressurization type loading. For HELBs located in other closed compartments in the Auxiliary Building, analysis has demonstrated that significant pressurization of the compartment will not occur. (See footnote 1)

Table RAI-13: Comparison of Oconee HELB Design Basis with BTP MEB 3-1 (Revision 2)

BTP MEB 3-1 Section	Description	Oconee Design	Comments/Clarifications
B.1.c.(5)	Environmental Qualification of safety related equipment per SRP 3.11.	Partially Conforms	Equipment necessary to reach safe shutdown is environmentally qualified to the Environmental Qualification Criteria Manual. Oconee's response to IEB 79-01.b defines the Environmental Qualification program. (See footnote 1)
B.1.d	Identification of piping runs that contain postulated pipe ruptures required by B.1.c.	Conforms	High Energy systems have been identified and documented in Oconee plant calculations. Break locations within these systems likewise have been identified and documented in Oconee plant calculations.[2]
B.1.e.(1)	Postulation of critical cracks for ASME Class 1 piping based on stress located Outside Containment Penetration Areas.	Not Applicable	No Class 1 Piping outside containment.

[2] High Energy systems are identified in calculation OSC 8385. Break locations are identified in calculations OSC-7516.01 (Unit 1), OSC-7517.01 (Unit 2), and OSC 7518.01 (Unit 3).

Table RAI-13: Comparison of Oconee HELB Design Basis with BTP MEB 3-1 (Revision 2)

BTP MEB 3-1 Section	Description	Oconee Design	Comments/Clarifications
B.1.e.(2)	Postulation of critical cracks for ASME Class 2 & 3 piping (and non ASME Class 1, 2, or 3) based on stress for piping located Outside Containment Penetration Areas.	Partially Conforms	For seismically analyzed piping, critical cracks are to be postulated at locations were primary + secondary stress equals or exceeds .4 x (Sa + Sh), determined in accordance with USAS B31.1 (1967 Edition).
B.1.e.(3)	Postulation of critical cracks in non safety class, non-analyzed piping located Outside Containment Penetration Areas.	Does not conform	Critical cracks are not postulated for non analyzed piping since the effects from postulated pipe breaks would bound the effects from critical cracks. Pipe ruptures are postulated for non-analyzed piping at all pipe girth welds. (See response to B.1.c.(3))
B.2.a	Separation of Essential Systems for Critical Cracks in Moderate Energy Systems.	Does not conform	Oconee not designed as a moderate energy plant.
B.2.b	Postulation of Critical Cracks in Containment Penetration Areas for Moderate Energy Systems.	Does not conform	Oconee not designed as a moderate energy plant. See response to Section B.1.b.
B.2.c.(1)(a)	Exemption to postulation of critical cracks for Moderate Energy Systems outside of the containment penetration areas.	Does not conform	Oconee not designed as a moderate energy plant.

Table RAI-13: Comparison of Oconee HELB Design Basis with BTP MEB 3-1 (Revision 2)

BTP MEB 3-1 Section	Description	Oconee Design	Comments/Clarifications
B.2.c.(1)(b)	Postulation of critical cracks for moderate energy ASME Class 1 piping outside of the containment penetration areas based on stress analysis.	Not Applicable	No moderate energy Class 1 piping outside containment.
B.2.c.(1)(c)	Postulation of critical cracks for moderate energy ASME Class 2 or 3 piping outside of the containment penetration areas based on stress analysis.	Does not conform	Oconee not designed as a moderate energy plant.
B.2.c.(2)	Postulation of critical cracks for moderate energy piping not exempted by B.2.c.(1)	Does not conform	Oconee not designed as a moderate energy plant.
B.2.c.(3)	Postulation of critical cracks for non seismic moderate energy piping.	Does not conform	Oconee not designed as a moderate energy plant.
B.2.d	Postulation of critical cracks in moderate energy systems in proximity to high energy systems.	Does not conform	Oconee not designed as a moderate energy plant.
B.2.e	Postulation of critical cracks in piping systems that qualifies as high energy systems for short operational periods.	Does not conform	Oconee not designed as a moderate energy plant. Certain piping systems are high energy for short operational periods. For those systems, critical cracks are not postulated.

Table RAI-13: Comparison of Oconee HELB Design Basis with BTP MEB 3-1 (Revision 2)

BTP MEB 3-1 Section	Description	Oconee Design	Comments/Clarifications
B.3.a.(1)	Postulation of circumferential breaks. Exemption of postulation of circumferential breaks for piping exceeding 1"nominal pipe size, except when hoop stress exceeds longitudinal stress by a factor of 1.5. Requirement that instrument lines meet Reg. Guide 1.11	Partially Conforms	Circumferential breaks postulated at locations determined in accordance with the response to items B.1.b, B.1.c.(2)(a), & B.1.c.(3). Exemption for postulation of circumferential breaks when actual stress greater than break threshold, but the hoop stress exceeds the longitudinal stress by a factor of 1.5 not taken. Instrument lines do not meet Reg. Guide 1.11
B.3.a.(2)	Postulation of circumferential breaks for non analyzed lines	Conforms	
B.3.a.(3)	Circumferential breaks should result in complete severance and separation amounting to at least one diameter lateral displacement.	Conforms	
B.3.a.(4)	Dynamic force of the jet from circumferential breaks should be based on effective flow area and on a calculated fluid pressure as modified by a thrust coefficient. Obstructions to flow or absence of energy reservoirs may be taken into account for reduction of the jet discharge.	Conforms	Dynamic forces determined in accordance with ANS 58.2 (1988).

Table RAI-13: Comparison of Oconee HELB Design Basis with BTP MEB 3-1 (Revision 2)

BTP MEB 3-1 Section	Description	Oconee Design	Comments/Clarifications
B.3.a.(5)	Pipe whip from circumferential breaks should occur in the plane defined by the piping geometry and pipe movement should be in the direction of the jet reaction.	Conforms	
B.3.b.(1)	Postulation of longitudinal breaks. Exemption of postulation of longitudinal breaks for piping equal to and exceeding 4"nominal pipe size, when hoop stress exceeds longitudinal stress by a factor of 1.5.	Conforms	Exemption not taken.
B.3.b.(2)	Longitudinal breaks need not be postulated at terminal ends.	Conforms	
B.3.b.(3)	Orientation of longitudinal breaks.	Conforms	
B.3.b.(4)	Dynamic force of the jet from longitudinal breaks should be based on effective flow area and on a calculated fluid pressure as modified by a thrust coefficient. Obstructions to flow or absence of energy reservoirs may be taken into account for reduction of the jet discharge.	Conforms	Dynamic forces determined in accordance with ANS 58.2 (1988).
B.3.b.(5)	Piping movement should be assumed to occur in the direction of the jet reaction unless limited by structural restraints or piping stiffness.	Conforms	

Table RAI-13: Comparison of Oconee HELB Design Basis with BTP MEB 3-1 (Revision 2)

BTP MEB 3-1 Section	Description	Oconee Design	Comments/Clarifications
B.3.c.	Leakage cracks should be postulated at those locations specified in B.1.e for high energy piping, and B.2.c.(1) for moderate energy piping.	Partially Conforms	Leakage cracks postulated for high energy piping, but not for moderate energy piping. Oconee is not designed as a moderate energy plant.
B.3.c.(1)	Leakage cracks need not be postulated in piping 1" and smaller.	Conforms	
B.3.c.(2)	For high energy systems, leakage cracks should be postulated at circumferential locations that result in the most severe environmental conditions. For moderate energy systems, see B.2.c.(2)	Partially Conforms	Leakage cracks postulated for high energy piping at locations postulated in accordance with response to B.1.e.(2). No cracks are to be postulated for non-safety piping locations in accordance with response to B.1.e.(3).
B.3.c.(3)	Fluid flow from a leakage crack shall be based on circular opening of area equal to ½ the piping diameter by ½ the piping wall thickness.	Conforms	

Table RAI-13: Comparison of Oconee HELB Design Basis with BTP MEB 3-1 (Revision 2)

BTP MEB 3-1 Section	Description	Oconee Design	Comments/Clarifications
B.3.c.(4)	Flow from a leakage crack should be assumed to result in an environment that wets all unprotected components within the compartment and communicating compartments. Flooding should also be assumed for the compartment containing the leakage crack and those communicating compartments. Flooding effects should be based on a conservative estimate of the time period required to effect corrective actions.	Partially Conforms	Universal wetting of all components necessary to achieve cold shutdown from leakage cracks located within closed compartments are not assumed. 'Direction wetting' associated with jet impingement will be assumed and components necessary to achieve cold shutdown will be protected from 'directional wetting.' Flooding effects are considered as appropriate.

Response Documentation for:

RAI 41

ITEM #	NRC Issue	DUKE COMMENTS	RESOLUTION OF ITEMS
C1	**Design Considerations for PSW/HPI** a. "...the commitment should specify that the PSW/HPI and related switchgear modifications will satisfy safety-related, seismic Category 1 criteria, and will be controlled and maintained in accordance with 10 CFR 50, Appendix B criteria." "The 'PSW System would be designed and constructed to meet Duke's standards for a safety-related system (QA-1).' Why isn't this characterized as a commitment (see Page 10 of Attachment 3, "Regulatory Commitment Table," fifth bullet)?" "While the licensee seems to suggest that the PSW/HPI system will be installed as safety-related, seismic Category 1, and will be controlled in accordance with 10 CFR 50 Appendix B requirements, this needs to be clearly stated to assure that there is no misunderstanding." b. "Why aren't PSW/HPI design criteria and time critical actions included similar to HELB commitments that were made?" "...why aren't these PSW/HPI design considerations reflected in the tornado commitments?"	a. The intent was to include the PSW/HPI System and the East Penetration Room flood prevention modifications to be designed and constructed to meet Duke's standards for a safety-related system (QA-1) per the Duke Quality Assurance Program Topical Report and described as such on the LAR. b. This was simply an attempt to reduce duplication within the letter.	a. Agreed - Common Understanding – No Further Action Required b. Agreed - Common Understanding – No Further Action Required
C2	**GL 91-18 Actions** a. "While HELB and tornado mitigation strategies are being implemented, any future issues that are identified as a result of these activities will be entered into Oconee Nuclear Station (ONS) corrective action program - no mention of GL 91-18 actions to address issues of this nature, or other actions that will be taken to assure that NRC requirements are satisfied."	a. The Duke Corrective Action Program requires items entered into the corrective action program to be evaluated for applicability of Operability and actions needed to address compliance with NRC requirements (NRC Inspection Manual Part 9900).	a. Agreed - Common Understanding – No Further Action Required
C3	**SSF Risk Reduction Effort** a. "In parallel with this, a risk reduction effort has been initiated that is intended to improve the reliability and availability of the standby shutdown facility (SSF) - there was no mention of a commitment or follow up with the NRC for this item."	a. The SSF risk reduction effort was initiated in 2005 in order to improve the reliability and availability of the SSF independent of resolution of tornado and HELB licensing basis issues.	a. Agreed - Common Understanding – No Further Action Required

ITEM #	NRC Issue	DUKE COMMENTS	RESOLUTION OF ITEMS
H1	<u>Volumetric Inspections of Piping In lieu of Protection of Equipment</u> "In Attachment 4 to the November 2006 letter, Duke proposes to use periodic volumetric examinations in lieu of evaluating the effects of pipe rupture at most of the pipe rupture locations in the turbine and auxiliary buildings. The proposed alternative to use periodic volumetric examinations in lieu of pipe rupture evaluation is not part of the criteria contained in the Giambusso letter or the criteria contained in BTP MEB 3-1. BTP MEB 3-1 requires 100% volumetric examination of all welded connections between the containment isolation valves in addition to meeting the stress limits specified in B.1.b of the BTP MEB 3-1. The basis for the BTP MEB 3-1 criteria is to provide a high level of assurance that breaks do not occur in the critical area between the containment isolation valves. BTP MEB 3-1 does not contain a provision for performing periodic volumetric examinations as an alternative to postulating the pipe cracks and ruptures at the locations required by BTP MEB 3-1."	Oconee proposes that for those postulated break or crack locations that have the potential to affect systems and components necessary to reach safe shutdown, including those that could affect the main steam pressure boundary, and those locations that have the potential to affect the turbine building structure, periodic volumetric inspections would be instituted in lieu of providing protection (e.g. pipe whip restraints, jet shields, etc.). While the exact number of inspection locations is uncertain at this time, it is generally believed to be less than 50 locations per unit. More than four thousand break locations per unit have been evaluated, so the characterization of 'most' is inaccurate. Oconee believes that detection and prevention of a postulated break location is superior to providing physical protection. Further, such structural modifications would (1) not provide a risk benefit, (2) would hamper normal plant maintenance activities, and (3) limit inspection access to the very location(s) where the break(s) are postulated. There is some precedent in this area. Another B&W unit, similar to Oconee, has incorporated a similar inspection program into their technical specifications, although not to the scale proposed by Oconee. Finally, the proposed program is a logical extension of the in-service Inspection plan, where periodic inspections are used to demonstrate the structural integrity of safety related piping.	Agreed - Open Issue. *[No credit is taken for these inspections with regards to the identification of postulated HELBs in the Turbine Building and Auxiliary Building.]*
H2	<u>BTP MEB 3-1 USE</u> "Revision 2 to BTP MEB 3-1 also contains additional criteria not provided in the Giambusso letter. The staff has repeatedly requested Duke to compare its proposed HELB criteria with the full criteria contained in BTP MEB 3-1 in order for the staff to perform a thorough safety review of the Duke HELB proposal. The November 30, 2006, letter only addresses the criteria from BTP MEB 3-1 which provide relaxations to the Oconee licensing basis HELB criteria." "In order for the staff to perform this licensing amendment review, it will be necessary for Duke to clearly address how its proposed new licensing basis meets all the criteria in BTP MEB 3-1 or provide a basis for any deviations to the criteria. While most of the specific commitments proposed by Duke in the November 30, 2006, letter are considered to be acceptable, the staff does not fully agree with those that relate to the specific issues identified below." "Duke needs to provide a specific justification for each pipe rupture location it plans to deviate from the staff guidance in BTP MEB 3-1."	Oconee's HELB design basis will continue to be the Giambusso/Schwencer letters, as amended by GL 87-11 and our letter dated 11/30/06. Oconee does not plan to adopt MEB 3-1 except as noted below. GL 87-11 notes that "Licensees of operating plants desiring to eliminate previously required effects from arbitrary intermediate pipe ruptures may do so without prior NRC approval, unless such changes conflict with the license or technical specifications." Oconee believes no further justification is needed for the adoption of GL 87-11, beyond that prescribed by the GL. Other facilities have adopted GL 87-11 in a similar fashion. The 11/30/06 letter describes the use of MEB 3-1 on two occasions: (1) For piping that is not analyzed or does not include seismic loadings; intermediate breaks will be postulated as provided in MEB 3-1. This means that breaks will be postulated at all girth weld locations irrespective of the stresses in the pipe. This clearly is not a deviation from Giambusso/Schwencer, which stipulates that a minimum of two breaks per run be postulated. This approach is more conservative than Giambusso/Schwencer. (2) For equivalent Class 2 and 3 piping that is seismically analyzed, critical cracks will be postulated at axial locations where the calculated stress for the applicable load case exceed .4(Sa + Sh). This is a deviation from Giambusso/Schwencer, which stipulates that critical cracks be postulated at the most adverse location independent of stress. However, the 11/30/06 letter justifies this by noting that "Adoption of this provision will allow the station to focus attention to those medium and high stress areas that have a higher potential for leakage cracks to form."	Agreed - Common Understanding - additional information to be provided in the LAR. *[Information on the use of criteria in BTP MEB 3-1 is provided. The criteria, upon which the HELB Break locations and types are determined, are identified in Section 2.0 of the HELB Report. The listed criteria identify how and where break locations and types are chosen.]*

ITEM #	NRC Issue	DUKE COMMENTS	RESOLUTION OF ITEMS
H3	**Definition of High Energy System per Footnote 5 of MEB 3-1** "...the Duke letter does not indicate whether its proposal fully satisfies the position in footnote 5 of BTP MEB 3-1, Revision 2. Specifically, footnote 5 states that systems operated during PWR startup, hot standby, or shutdown qualify as high energy systems. Duke needs to clarify that it will satisfy the definition of high energy system contained in footnote 5 of BTP MEB 3-1."	Oconee has no plans to adopt any other portions of MEB 3-1, including footnote 5. As regards footnote 5, Oconee plans to eliminate systems that operate for short periods of time at high energy conditions due to the low probability of a break occurring during high energy operations. We previously communicated that we would provide historical information regarding system operating times in the LAR(s).	Common Understanding - Additional information to be provided in the LAR. (Reference NRC letter dated 7/12/2006, Enclosure 2, Item 18) *[The definition of a high energy system is provided in Section 1.5 of the HELB Report.]*
H4	**Postulation of Terminal End High Energy Line Breaks at Closed Ended Valves** "The Duke letter does not indicate whether its proposal fully satisfies the position in footnote 3 of BTP MEB 3-1. Specifically, footnote 3 states that for piping runs which are maintained pressurized during normal plant conditions for only a portion of the run (i.e., up to the first normally closed valve) a terminal end of such runs is the piping connection to this closed valve. This means that a pipe rupture would have to be postulated at the connection to the closed valve. Duke needs to clarify that it will satisfy the complete criteria contained in footnote 3 of BTP MEB 3-1."	Although not addressed by Giambusso/Schwencer, Oconee intends to postulate breaks/cracks at closed valves as follows: The postulation of terminal end breaks at the first normally closed valve(s) separating portions of a system maintained pressurized during normal operations and portions of a system not maintained pressurized depends on whether the system has a seismic analysis that is continuous across the valve. For system or portions of systems that are not seismically analyzed, breaks are postulated to occur at all piping girth welds in the system including those that attach to normally closed valves. For systems or portions of systems that are seismically analyzed, and the analysis is continuous across the normally closed valve, such that stresses can be accurately determined, break and crack locations are determined based on comparison to the break and crack stress thresholds. This interpretation for boundary valves in seismically analyzed lines has been previously approved by the staff for the LPI cross tie submittal (Oconee), for the revised pipe rupture analysis criteria (Crystal River), and for the "Determination of Break Locations and Dynamic Effects Associated with the Postulated Rupture of Piping" (Watts Bar).	Agreed - Common understanding - No additional action
H5	**Treatment of the Letdown Line as a High Energy Line** "In Attachment 5 to the November 2006 letter, Duke argues that the reactor coolant letdown line outside the containment does not qualify as a high energy system in accordance with its licensing basis because the system does not exceed both 200 degrees F and 275 psig. However, the Oconee licensing basis criteria provided in Duke Report No. OS-73.2, "Analysis of the Effects Resulting from Postulated Piping Breaks Outside Containment for Oconee Nuclear Station, Units 1, 2, and 3," clearly states that a higher energy lines are defined as those that have either a normal service temperature greater than 200 degrees or a pressure greater than 275 psig. This is the same criterion that is referenced in BTP MEB 3-1. Duke needs to treat the reactor coolant letdown line as a high energy line up to the isolation valve."	Oconee agrees that the Letdown line should be considered as high energy. However, upon rereading the original SER for Oconee, there seems to be some confusion on this point. The SER clearly notes the following, "The reactor coolant letdown is cooled before leaving the reactor building so this system is essentially a high pressure system rather that a high pressure and temperature system." Although not explicitly stated in the SER, it is believed by Oconee that this statement allowed some latitude in the postulation of single active failures, as follows:	Agreed - Common understanding - No additional action

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ITEM #	NRC Issue	DUKE COMMENTS	RESOLUTION OF ITEMS
H6	<u>**Single Active Failure Criterion for the Letdown Line Break between the Containment Penetration and the Outboard Containment Isolation Valve**</u> "...the NRC staff does not agree with the licensee's characterization in this commitment of the plant licensing basis relative to the letdown line; the single failure criterion is applicable and must be considered..." "Contrary to Duke's position, the MDS Report (Section 3.1.9) indicates that the break is isolated by automatic closure of xHP-3, xHP-4, and xHP-5; and Duke did not take exception to the single failure criterion for this break scenario. In fact, for those break locations where the MDS report did find that the single failure criterion was not satisfied, the condition was specifically recognized and interim compensatory measures and plant modifications were identified for resolving the single failure discrepancies that were found. Furthermore, Duke indicated that the NRC criteria that were specified for addressing HELB were satisfied. Therefore, the plant licensing basis for postulated failures of the letdown line includes consideration of single active failures." "It is the NRC staff's position that the plant licensing basis for postulated failures of the letdown line includes consideration of single active failures, and postulated failures of the letdown lines for the Oconee units must be addressed accordingly."	It is clear that no single active failure was postulated in the original MDS report. The report noted that valves HP-3, 4, & 5 could be used to isolate the break. However, HP-3 and 4 are located in parallel lines downstream of their respective Letdown Coolers, upstream of the break location. HP-5 is located outside containment, downstream of the postulated break location. So, a failure of HP-3 or 4 to close would result in an un-isolated break. Closing HP-5 was and is not important, since it is downstream of the break location. However, HP-1 & 2 can be closed, by manual operator action inside the control room to isolate the break. Oconee will include, as part of the LAR(s), a description of the dose re-analysis of this break scenario, crediting closure of HP-1 & 2 to isolate the break.	Agreed - Common Understanding - additional information to be provided in the LAR. *[This information is provided in Sections 4.0 - 6.0 for each unit, described in Section 7.3, and the modification to xHP-1 and xHP-2 is described in Section 9.0. No further action on this item is required.]*
H7	<u>**Location of Terminal End Breaks at Small Bore Reactor Building Penetrations**</u> "In Attachment 4 to the November 2006 letter, Duke indicates that breaks will not be postulated at the penetration anchors for small bore piping penetrations because the penetration anchors are located inside the containment. Instead, Duke indicates that breaks are postulated in the piping run outside the containment wall and remote from the anchor. This is not consistent with the criteria provided in Section 2.1 of Duke Report No. OS-73.2 which requires break locations at the terminal end of the piping run. BTP MEB 3-1 also requires postulation of breaks at the terminal end. The basis for the criteria is that breaks are expected to occur at locations that provide rigid constraint to the piping, such as anchor points. Duke needs to either evaluate the effect of pipe breaks at the terminal end (anchor point) as required by the criteria or provide justification as to why the alternative location it selected is the most likely location for a HELB."	The MDS report provided drawings of break locations at the small bore Reactor Building penetrations. These locations were clearly inside the penetration rooms, beyond the piping to reactor building liner welds. In addition, the aforementioned SER provides the following: "The staff agrees with the applicant's selection of pipe failure locations and concludes that all required accident situations have been addressed appropriately by the applicant." The consequences of the small bore break locations at the RB penetrations documented in the MDS report would be very similar as to those postulated at the piping to liner welds, except in one respect, their affect on containment integrity. However, other analyses evaluated the affect on containment should a break occur at the pipe to liner weld, as part of the containment design. The design basis for these analyses is described in Section 3.6.1.1 of the UFSAR. The design basis is as follows: (1) All penetrations are designed to maintain containment integrity for any loss of coolant accident combination of containment pressures and temperatures. (2) All penetrations are designed to withstand line rupture forces and moments generated by their own rupture as based on their respective design pressures and temperatures. (3) All primary penetrations, and all secondary penetrations that would be damaged by a primary break, are designed to maintain containment integrity. (4) All secondary lines whose breaks could damage a primary line and also breach containment are designed to maintain containment integrity. In conclusion, Oconee does not believe that it is necessary to change the licensing basis for postulation of breaks at small bore penetrations.	Agreed - Common Understanding - additional information to be provided in the LAR. *[This information is not explicitly addressed in the HELB Report, although all small bore postulated breaks at the Reactor Building Penetrations have been analyzed and described. Information on the exact point of the break on the line is not provided. However, since this appears to apply only to the Letdown Line and the RCP Seal Injection Lines, further information is not necessary. The effects of these breaks are addressed in the HELB Report, sections 4.2, 5.2, & 6.2.]*

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H8	**Location of Terminal End Break at the Main Steam Reactor Building Penetration** "In Attachment 5 to the November 2006 letter, Duke indicates that breaks were not postulated at the east penetration room main steam terminal end anchor point because the penetration anchor is located inside the containment. Instead, Duke indicates that the break is postulated in the piping run outside the containment wall and remote from the anchor. This is not consistent with the criteria provided in Section 2.1 of Duke Report No. OS-73.2 which requires break locations at the terminal end of the piping system. Duke needs to either evaluate the effect of a pipe break at the terminal end (anchor point) as required by the criteria or provide justification as to why the alternative location it selected is the most likely location for a HELB."	The MDS report provided drawings of the two Main Steam break locations at the Reactor Building penetrations. These locations were clearly inside the penetration rooms, beyond the MS rupture restraints and the Reactor Building liner welds. As noted for the small bore breaks at the RB penetrations, the SER agreed with the selection by Oconee of the pipe failure locations and further concluded that all required accident situations had been appropriately addressed. The consequences of a MS break at the locations depicted in the MDS report would be very similar to those postulated at the MS rupture restraint. The rupture restraint, which forms part of the containment boundary, is connected to the MS piping by two welds. These welds connect the MS piping to a collar plate that is in turn welded to the rupture restraint. The inboard weld (RB Side) is designed such that should a break occur at the outboard weld (EPR side) containment integrity would not be threatened. Similarly, the outboard weld is designed such that should a break occur at the inboard weld containment integrity would not be threatened. The design of MS penetration and rupture restraint form part of the overall containment design. In conclusion, Oconee does not believe that it is necessary to change the licensing basis for postulation of breaks at the Main Steam penetrations.	Agreed - Common Understanding - additional information to be provided in the LAR. *[Pages 8-3 to 8-5 of the HELB Report only address the Feedwater Line restraint. Main Steam and small bore pipe penetrations [including drawings] are describe in Duke Energy's response to RAI 10 from the 10/23/2009 RAI response submittal.]*
H9	**Water Hammer Loads** "How are water hammer loads addressed?"	For those piping systems where water hammer is a concern (Main Steam & Main Feedwater), the calculation of Equation 9 (occasional loads) is based on the greater of OBE seismic or water hammer stresses.	Agreed - Common Understanding - Additional information to be provided in the LAR. *[The water hammer loads have been included in the Piping Analysis Calculations for the main feedwater, and the steam hammer loads have been included in the piping analysis calculations for the main steam piping. These piping analysis calculations are listed in the HELB Report tables in calculations OSC-7516.01 (unit 1), OSC-7517.01 (unit 2), OSC-7518.01 (unit 3.]*
H10	**Technical Specifications for PSW & SSF** "...licensing basis clarity should be reflected in the UFSAR, and TS requirements should be established in accordance with 10 CFR 50.36 requirements." "Operability of the water inventory for the SSF and PSW/HPI must be addressed. The current SSF TS in this regard was based on the availability of other systems such as EFW for performing the SSDHR function, which is not valid for the proposed tornado and TB HELB mitigation strategies. Furthermore, both the SSF and the PSW/HPI systems rely upon the same water supply and the licensee has not addressed how the water supply will be assured for both tornado and HELB mitigation." "Indicates that installation of PSW and HPI improvements will reduce reliance on the SSF by providing a system capable of independently establishing safe shutdown conditions, thereby significantly improving overall plant risk - not truly independent due to shared water source and west penetration room (WPR) vulnerabilities; no mention of establishing a Technical Specification (TS) requirement pursuant to 10 CFR 50.36 even though the	Oconee agrees that licensing basis for HELB will be reflected in the UFSAR. As documented in our 11/30/06 letter, the PSW has been evaluated regarding inclusion into the TS, and that evaluation concluded that the PSW operability requirements should be incorporated into the Selected Licensing Commitments (SLC) Manual and its Bases. This conclusion was based on 10CFR50.36 requirements, preliminary Oconee PRA results, and the applicability of NUREG 1430 for standard technical specifications. Regarding the assurance of the water supply for both SSF and PSW/HPI, see Issue H12. The SSF will remain risk significant and its TS will remain as	Agreed - Common Understanding - Additional information to be provided in the LAR concerning a TS or SLC for only. Agreed - Common Understanding - Additional information to be provided in the LAR concerning RCS leakage. Agreed - Common Understanding - Additional information to be provided in the LAR concerning the submersible pump.. *[The Technical Specifications for the PSW system are provided in Attachment 2 of the Unit 1 HELB LAR. This information includes the surveillance requirements for the Submersible Pump. The issue of RCS leakage and SSF RC Make-Up Pump is not unique to the HELB Project, and it is not included in the HELB Report.]*

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	licensee recognizes that the PSW/HPI modifications will "significantly" improve overall plant risk." A TS is required for the PSW/HPI system in accordance with 10 CFR 50.36(c) (2) (ii) (D). As stated on Page 3 of the November 30, 2006, submittal, Duke indicated that "the installation of a new PSW system and HPI system improvements will reduce reliance on the SSF by providing a system capable of independently establishing safe shutdown conditions, and thereby significantly improve overall plant risk." TS requirements were required for the SSF to assure its SSDHR function (even though other sources of SSDHR were considered to be available). The risk significance of the PSW/HPI system is on the same order of magnitude as the SSF and in this case, other sources of SSDHR may not be available. * Tornado and HELB events at Oconee represent at least the same level of risk as associated with design basis accidents (DBAs). * The licensee proposes to rely upon the PSW/HPI system in conjunction with the SSF for tornado and HELB mitigation, and the licensee's TORMIS analysis is predicated on this. Therefore, TS requirements should be established not only to assure the operability of the PSW/HPI system, but also to assure that both the SSF and PSW/HPI systems are not both rendered inoperable at the same time. "The PSW/HPI capability is the only means that can be relied upon for tornado and HELB mitigation beyond 72-hours, and it is the only means available for cooling down the Oconee units. "What limitations are required relative to reactor coolant system (RCS) leakage when using the MSRVs and atmospheric dump valves (ADVs) for steam generator (SG) pressure control and crediting the SSF, and what changes are necessary to the TS in this regard?" "The plant licensing basis for both tornado and HELB includes the capability to achieve and maintain cold shutdown conditions. In the case of tornado, the station ASW system is credited for being able to maintain SSD for at least 30 days and the same capability should be provided by the PSW/HPI system. The submittal needs to explain how this capability will be assured, especially with respect to TS requirements." "TS requirements that assure the operability and availability of structures, systems and components (SSCs) that are relied upon for the tornado and HELB mitigation strategies must be established, such as for the standby shutdown facility (SSF), the PSW/HPI system, the Unit 2 condenser circulating water (CCW) system, and for reactor coolant system leakage." "The current SSF TS requirements did not include consideration of the proposed mitigation strategy and the current 45 day allowed outage time (AOT) for the Unit 2 CCW inlet is of concern. This needs to be reconsidered since the basis for the 45 day AOT is no longer valid, and the AOT should be limited based on tornado and HELB considerations recognizing that there are not other sources of water." "Page 3, first bullet: Relative to the capability to power the submersible pump by the PSW switchgear, what TS operability and surveillance requirements are appropriate?"	currently written. As noted in the 11/30/06 letter, the new PSW system will not mitigate any Oconee UFSAR Chapter 15 design basis events. Further, preliminary PRA indicates that the risk impact of PSW intended functions are lower than those of SSF. The addition of PSW/HPI actually reduces the safety significance of the SSF. Additionally, preliminary PRA analysis indicates that the AOT for the PSW/HPI system would be ~21 days as compared to the 7 day AOT of the SSF. Currently, the limiting condition for RCS leakage is maintained in accordance with TS 3.4.13 and the limiting condition for operation of the SSF is maintained in accordance with TS 3.10. The Commitment relative to operation of the Station ASW and SSF for the purpose of tornado mitigation is in accordance with SLC 16.9.9. The Maximum Allowed Total Combined RCS Leakage Rate was chosen to ensure that the seal leakage rate for all four (4) RC pumps plus other RCS leakage during normal operation remains low enough to allow the SSF RC Make Up System to maintain adequate inventory in the RCS to sustain natural circulation flow during an SSF event. The original Station ASW system, that also takes suction form the CCW header, is governed by SLCs, not TSs. The combined PSW/HPI and SSF tornado and HELB mitigation functions will be monitored using a revised version of SLC 16.9.9.	

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		The limiting condition for the submersible pump is outlined in TS 3.10.1.b. The submersible pump provides long term makeup to the reservoir. The submersible pump is stored in the SSF facility. The surveillance requirements will remain the same. (See 1st bullet, Page 3 of Attachment 1 and Sections 1.1 and 1.2 of Attachment 2 in the November 30, 2006 letter)	
H11	<u>72 Hour Mission Time of the SSF</u> "The plant licensing basis is to be able to mitigate HELB events, including consideration of single active failures, and to place the plant in cold shutdown condition. The onus is on the licensee to demonstrate that the 72-hour mission time of the SSF is adequate for this purpose (e.g., extent of damage and time required to make necessary repairs and to resolve postulated failures of the PSW/HPI must be addressed)." "The 72-hour mission time of the SSF does not establish what the mission time is for mitigating HELB scenarios. Adequate assurance must be established that the PSW/HPI and SSF are capable of mitigating the HELB event to the point of establishing cold shutdown conditions, irrespective of the SSF mission time. The 30-day capability of the PSW/HPI system can be credited in this regard, but assurance that sufficient water inventory will be available and that the PSW/HPI can be restored within 72-hours is required."	The proposed HELB design basis is predicted on the ability to reach safe shutdown(1) within 72 hours. The SSF can adequately provide this function. Within the 72 hour timeframe, damage repair measures will be credited to insure the required systems and components are available such that an orderly progression to cold shutdown can begin. Oconee agrees that more detail should be provided (i.e. PSW single failure mitigation) on the scope and detail of these repair measures. Such detail and scope can be provided in the unit specific LAR(s). Regarding the availability of the water source to the SSF and PSW/HPI, there are no direct threats to the supply from postulated HELBs. With the use of the submersible pump discussed elsewhere in this presentation, the CCW can be replenished from the Lake Keowee source indefinitely. Again such detail can be provided in the LAR(s).	Agreed - Common Understanding - Additional information to be provided in the LAR. *[This information is provided in Section 3.3 of the HELB Report. Moreover, the statement is made that the PSW-ASW System will be restored to operability within 72 hours.]*
H12	<u>Assurance of Suction Source</u> "Contrary to the information that was provided, this PSW/HPI system is not totally independent of the standby shutdown facility because they share the same water source." Furthermore, both the SSF and the PSW/HPI systems rely upon the same water supply and the licensee has not addressed how the water supply will be assured for both tornado and HELB mitigation." "How is water supply from the Unit 2 CCW assured to be available? The existing TS AOT must be reconsidered accordingly recognizing the new tornado and HELB mitigation functions." "The licensing basis includes the capability to place the plant in cold shutdown and the mitigation strategy does not adequately address how this capability is assured relative to the extent of damage that can be experienced, recognizing that: a) it is critical to recover PSW/HPI within the 72-hour mission time of the SSF, and b) an assured source of cooling water that is good for at least 30-days is needed for the three Oconee units at the onset of	Oconee agrees that the water source for both SSF and PSW/HPI is not redundant. However, given that either system, but not both, will draw on this source, and given the available inventory, HELBs in the TB that result in the loss of 4160V, can be adequately mitigated such that safe shutdown(1) can be maintained for 72 hours following the event by use of the submersible pump. Following that period, there remains adequate CCW inventory to support an orderly cooldown to cold shutdown. Should the cooldown period exceed the capacity of the available inventory, the submersible pump can be used to refill the CCW from Lake Keowee. This activity can be easily achieved before depletion of the available inventory.	Agreed - Common Understanding - Additional information to be provided in the LAR. *[The PSW System and the SSF System share the same source of water for the PSW and SSF-ASW Subsystems. However, as stated in Sections 3.2 and 3.3 of the HELB Report the source is the water contained in the "Unit 2 CCW imbedded piping," which is a passive source. The report also states that the SSF is a backup to the PSW, which means that PSW and SSF will not be used simultaneously, and the submersible pump can be used to refill this source. All of this information is provided in Sections 3.2 & 3.3 and is used in the interaction analysis. No further actions or clarifications are required.]*

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	tornado and HELB events." SSF and PSW will both use the Unit 2 condenser circulating water (CCW) inlet piping as a water source. How will availability of this water source be assured?		
H13	<u>Main Steam HELBS</u> "...the SSF cannot be credited as backup if the non-MS HELB results in a plant cooldown that exceeds SSF reactor coolant system (RCS) makeup capability, such as the turbine bypass valve (TBV) and feedwater control valve (FWCV) failures that are referred to on page 10 (for example). Also, it would seem that if this is a problem for non-MS HELBs, that it would be a problem for MS and main feedwater (MF) HELBs (also see Page 11, third paragraph)? Per Page 10, third paragraph, Duke to confirm the adequacy of previous analysis that the MS HELBs in the turbine building satisfies the specified criteria (no damage to protection systems, Class 1E electrical systems, or ES equipment on the affected unit, plus single failure consideration) such that the PSW/HPI and SSF do not have to be credited "The SSF cannot be credited for backup mitigation if the non-main steam (MS) HELB results in a plant cooldown that exceeds SSF RCS makeup capability (which appears to be the case for postulated turbine bypass valve (TBV) and feedwater control valve (FWCV) failures as referred to in Attachment 4, page 10, of the submittal (for example)."	Oconee recognizes that the SSF RCMU has limited capacity for RCS inventory control. As noted in Oconee's response to Information Notice 79-22 and reiterated in our letter dated 11/30/06, the profile considered for the environmental evaluation of the turbine bypass valve and feedwater control valve was based on a MS break. Oconee has no information, at this time, that indicates that these valves fail open for non-Main Steam breaks. As indicated in the 11/30/06 letter, work continues on the mitigation strategy for MSLBs and other HELBs that may result in a compromise of the MS pressure boundary. This analysis will consider non-safety control system malfunctions induced by environmental effects, the validity of the assumed environmental profile in the TB and the capabilities of the PSW/HPI system and the SSF to mitigate these HELBs.	Agreed - Common Understanding - Additional information to be provided in the LAR. See Item H1. *[These items are addressed in detail in Section 7.0 of the HELB Report. Moreover, Section 7.0 of the HELB report includes the analysis of the SSF/MSIV's for HELB event mitigation. No additional actions are necessary for these items.]*
H14	<u>HELB's and an Uncontrolled Blowdown of Either Steam Generator</u> "The consequences of HELB is determined based upon appropriate analyses, and the assumption that HELBs do not result in an uncontrolled blowdown of either SG (or excessive cooldown for that matter) must be justified accordingly, as well as any other assumptions that are credited in the HELB analyses. The HELB analyses must also address single failure considerations without exception." "The consequences of HELB are determined based upon appropriate analyses, and the assumption that HELBs do not result in an uncontrolled blowdown of either steam generator (SG), or excessive cooldown for that matter, must be justified accordingly (as well as any other assumptions that are credited in the HELB analyses)."	The unit specific LAR(s) will provide information and or references that demonstrate the consequences of all postulated HELBs. Information regarding a potential uncontrolled SG blowdown and the potential mitigation strategy will also be reported in the LAR, as appropriate. The postulation of single active failures will be addressed.	Agreed - Common Understanding - Additional information to be provided in the LAR. *[This information is provided in the break analysis in section 7.0 of the HELB Report and the individual break evaluations are provided in Sections 4.0, 5.0 & 6.0 of the HELB Report (ONDS-351).]*

ITEM #	NRC Issue	DUKE COMMENTS	RESOLUTION OF ITEMS
H15	**Control Room Cooling System & Main Steam Line HELBs In the Turbine Building** "...why isn't this sort of thing a problem for the MSLB in the TB (i.e., HELB in the TB can cause a loss of chilled water and power for HVAC; loss of colored buses)?"	As stated in the 11/30/06 letter, analysis has shown that the main CR would remain habitable and the equipment located there would there would remain functional for a prolonged loss of HVAC. The route of the Main Steam lines is not proximate to the CR. In addition, the TB is a large structure with numerous openings. As such, should a MSLB occur in the TB, the jet flow would be sufficiently far away from the CR such that the CR would continue to function, even with a loss of chilled water. Regarding the 4160V power, all direct interactions from HELBs postulated to occur in the TB are being evaluated, including interactions with the 4160V power.	Agreed - Common Understanding - Additional information to be provided in the LAR. (Reference NRC Letter dated July 12, 2006, Enclosure 2, Item 21) *[This item is addressed in Sections 3.8.1 and 8.0 (pages 8-29 and 8-30) of the HELB Report. Also, Sections 4.0 - 6.0 address the Turbine Building HELBs and their lack of interaction with the Auxiliary Building. No other action on this item is required.]*
H16	**Justification of 100% Humidity Non-Condensing** "The environmental profile is determined based upon analysis of the actual conditions that will exist following the pipe break, and the assumption that the environment is "non-condensing" must be justified and supported by the analysis." "The environmental profile is determined based upon analysis of the actual conditions that will exist following the pipe break, and the assumption that the environment is "non-condensing" must be justified and supported by the analysis."	As noted in Oconee's response to Information Notice 79-22 and reiterated in our letter dated 11/30/06, the profile considered for the environmental evaluation of the turbine bypass valve and feedwater control valve was based on a MS break. During normal operation, the SGs produce at least 60 degree superheated steam. Under such conditions, the amount of condensation is negligible.	Agreed - open issue Issue is really broader and concerns EQ. *[The Environmental Qualification Criteria Manual (EQCM) establishes the current licensing basis.]*
H17	**Restoration of PSW/HPI** "No flood protection will be provided for systems and components in the TB that are necessary to reach cold shutdown (CSD). This could require the plant to be maintained in safe shutdown (SSD) conditions for an extended period of time which places additional importance on the PSW/HPI capability since the SSF is only good for 72-hours. The extent of potential damage and single failures must be considered and addressed such that the capability to restore/use the PSW/HPI system is assured." "The licensing basis includes the capability to place the plant in cold shutdown and the mitigation strategy does not adequately address how this capability is assured relative to the extent of damage that can be experienced, recognizing that: a) it is critical to recover PSW/HPI within the 72-hour mission time of the SSF, and b) an assured source of cooling water that is good for at least 30-days is needed for the three Oconee units at the onset of tornado and HELB events."	As noted in our letter date 11/30/06, single active failures will be postulated, as appropriate, for initial event mitigation, to reach safe shutdown[1]. Should a single active failure occur in the PSW system during initial event mitigation, the SSF will be credited for initial event mitigation. Repair guidelines will be credited to restore the PSW system within the mission time of the SSF. Oconee agrees that the scope and detail of such repair guidelines needs to be described. These items will be provided in the LAR(s)	Agreed - Common Understanding - Additional information to be provided in the LAR. *[This item requests information to justify the statement that PSW system can be restored to operation within 72 hours. The HELB Report and the LAR reiterate this fact.]*
H18	**Seal Between the Reactor Building and the Auxiliary Building** "What is being done to assure that the seal between the reactor building (RB) and auxiliary building (AB) is properly maintained and does not leak excessively so that that flood mitigation features are not compromised?"	The seal between the RB and AB has been refurbished. This seal, as well as all other components required to prevent flooding of the AB following a MFDW break in the east penetration room, will be maintained as part of the station's civil passive features program (which is currently under development).	Agreed - Common understanding - No additional action

ITEM #	NRC Issue	DUKE COMMENTS	RESOLUTION OF ITEMS
H19	**Ability to Reach Cold Shutdown for Postulated HELBs** "...the licensing basis specifies the capability to place the Oconee units in cold shutdown condition and therefore, the licensee must be clear on what is being credited within the plant licensing basis in this regard such that the capability to achieve cold shutdown is assured." "The plant licensing basis is to be able to mitigate HELB events, including consideration of single active failures, and to place the plant in cold shutdown condition. The onus is on the licensee to demonstrate that the 72-hour mission time of the SSF is adequate for this purpose (e.g., extent of damage and time required to make necessary repairs and to resolve postulated failures of the PSW/HPI must be addressed)." "The plant licensing basis for both tornado and HELB includes the capability to achieve and maintain cold shutdown conditions. In the case of tornado, the station ASW system is credited for being able to maintain SSD for at least 30 days and the same capability should be provided by the PSW/HPI system. The submittal needs to explain how this capability will be assured, especially with respect to TS requirements." "The 72-hour mission time of the SSF does not establish what the mission time is for mitigating HELB scenarios. Adequate assurance must be established that the PSW/HPI and SSF are capable of mitigating the HELB event to the point of establishing cold shutdown conditions, irrespective of the SSF mission time. The 30-day capability of the PSW/HPI system can be credited in this regard, but assurance that sufficient water inventory will be available and that the PSW/HPI can be restored within 72-hours is required." "The plant licensing basis is to be able to mitigate HELB events, including the capability to place the plant in cold shutdown and consideration of single active failures. Loss of power is also postulated for those HELB events that can reasonably be expected to cause a loss of power, such as causing a trip of the main turbine." "The proposed licensing basis for HELB induced damage inside the TB indicates that no time-critical actions are required. The basis for this position is not obvious in that the SSF is only credited for 72-hours and the capability restore/use the PSW/HPI system prior to exceeding 72-hours is required. Also, the licensee needs to explain how a source of water for mitigating the HELB event is assured."	Adequate assurance will be provided in the unit specific LAR(s) that SSF or PSW/HPI can sustain the unit at safe shutdown[1] until cool-down can commence to cold shutdown. The LAR(s) will further demonstrate that an adequate source of water for SSF systems or PSW/HPI will be protected from HELBs and that the water inventory is adequate to sustain the function. It should be noted that for HELB events, crediting use of the submersible pump, the water can be supplied indefinitely (e.g. Lake Keowee). Should a single active failure occur on PSW/HPI, the SSF will be credited for initial event mitigation. Appropriate measures will be instituted and described in the unit specific LAR(s) to demonstrate that PSW/HPI can be restored within 72 hours. The equipment located inside the Turbine Building relied upon to establish cold shutdown is not protected from the effects of a HELB inside the Turbine Building. Subsequent to a HELB inside the Turbine Building, either the SSF or PSW/HPI system would be capable of providing secondary side decay heat removal and reactor coolant pump seal injection subsequent to a HELB event to maintain the affected units sub-cooled with a pressurizer steam bubble in safe shutdown[1] conditions for up to 72 hours. This mission time is consistent with the SSF current licensing basis. Additional damage repair may be required to enable the Low Pressure Service Water and the decay heat removal function of the Low Pressure Injection systems to achieve cold shutdown. For those events that cause loss of power, loss of power will be considered. There are no time critical operator actions inside the Turbine Building associated with plant cooldown or the establishment of cold shutdown.	Agreed - Common Understanding - Additional information to be provided in the LAR (Reference NRC Letter dated July 12, 2006, Enclosure 2, Item 2) *[Cold Shutdown is defined in Section 1.5 of the HELB Report (ONDS-351, R2) and the achievement of cold shutdown is identified as one of the shutdown intervals in Sections 3.5 and 3.6 of the HELB Report. The pathway for achieving cold shutdown for postulated HELBs in each unit is described in Sections 4.0, 5.0, and 6.0. Methodologies for achieving cold shutdown for specific postulated structural failures as a result of postulated HELBs are discussed in Section 8.0 of the HELB Report.]*
H20	**PSW/HPI Powering SSF** "HELB single active failure considerations rely to some extent upon the capability to align PSW/HPI power to the SSF. Therefore, contrary to the licensee's position as stated on Page 3 of Attachment 2, in Section 1.2, this capability should be included in the plant licensing basis." "HELB single active failure considerations rely upon the capability to align PSW/HPI power to the SSF. Therefore, contrary to the licensee's position (Section 1.2 on Page 3 of Attachment 2 of the submittal), it is necessary to credit this capability in the plant licensing basis."	The PSW/HPI power to the SSF is not necessary to mitigate a single failure within the initial 72 hours of the event. Therefore, it is Oconee's position that this function does need to be included in the licensing basis.	Agreed - Common Understanding - Additional information to be provided in the LAR *[The Duke response to this item said that crediting the PSW System to power the SSF is not necessary to mitigate postulated HELBs. Based upon the configuration of the PSW and SSF, the powering of the SSF with the PSW System for any postulated HELB is not necessary. This discussion is not in the HELB Report or any other part of the LAR.]*

ITEM #	NRC Issue	DUKE COMMENTS	RESOLUTION OF ITEMS
H21	<u>Main Steam Relief Valves (MSVRs) Cycling</u> "Page 3, first bullet: for how long and for how many cycles will the main steam relief valves (MSRVs) be credited; what assurance will be provided that they won't stick open, possibly compromising the mitigation strategy? What limitations are required relative to reactor coolant system (RCS) leakage when using the MSRVs and atmospheric dump valves (ADVs) for steam generator (SG) pressure control and crediting the SSF, and what changes are necessary to the TS in this regard?" "What are the maximum number of cycles the MSRVs will experience and why doesn't one or more MSRV sticking open pose a problem?" "The discussion indicates that steam pressure may be controlled using the ADVs to limit the number of MSRV cycles. What number of MSRV cycles are considered acceptable and why? What assurance is there that the MSRV cycles will be limited accordingly?"	Cycle test of a MSRV was completed 11/1/06. One thousand lift tests were conducted. At no time did the test relief valve stick open. Oconee views the results as a demonstration of the reliablity of the valves to perform their design basis function during SSF operations. In addition, the number of lift tests conducted bounds the number of lift cycles expected during the 72 hour SSF mission time.	Agreed - Common Understanding - Additional information to be provided in the LAR *[This information is not in the HELB or Tornado LARs. Duke is not imposing limits on the MSRVs with regard to the maximum number of cycles. The CLB credits the cycling of the MSRVs for up to 72 hours.]*

<u>Footnotes</u>

{1} "Safe Shutdown" for the Oconee Nuclear Station is defined as Mode 3 with average Reactor Coolant System (RCS) temperature $\geq 525°$ F. "Cold Shutdown" is defined as Mode 5 with RCS temperature $\leq 200°$ F.

	NRC ISSUE	DUKE COMMENTS	Resolutions
T1	**USE OF TORMIS** a. "Page 2, second paragraph: Any differences in the design of Units 2 and 3 that could compromise the proposed tornado mitigation strategy that is based on Unit 1 design considerations need to be specifically identified and addressed." b. "The use of TORMIS must be requested in a LAR, and the TORMIS analysis should be applied to all SSCs that can adversely impact the tornado mitigation strategy, not just those SSCs that perform the functions that support the updated tornado mitigation strategy. For example, if a tornado missile ruptures an ammonia tank in the vicinity of the ADVs making it impossible to access the ADVs, then the ammonia tank would have to be included in the TORMIS analysis. Another example: if tornado missiles cause a structural failure of the TB that impacts the tornado mitigation strategy (such as by causing a failure of MS or other high energy piping), this would have to be included." c. "Pages 3/4, second bullet: The TORMIS analysis should be applied to all structures, systems, and components (SSCs) that can adversely impact the *tornado mitigation strategy, not just those SSCs that perform the functions* that support the updated tornado mitigation strategy. For example, if a tornado missile ruptures an ammonia tank in the vicinity of the ADVs making it impossible to access the ADVs, then the ammonia tank would have to be included in the TORMIS analysis. Another example: if tornado missiles cause a structural failure of the turbine building (TB) that results in a failure of main steam (MS) or other high energy piping that can compromise the tornado mitigation strategy, this would have to be included." d. "Second bullet: the use of TORMIS for must be requested in a LAR and the TORMIS analysis should be applied to all SSCs (safety and non-safety related) that can adversely impact the tornado mitigation strategy, not just those SSCs that perform the functions that support the updated tornado mitigation strategy (a complete listing of SSCs included in the TORMIS analysis is required). The NRC staff will allow the use of TORMIS provided it is consistent with what has been approved for use by other licensees. Any exceptions to the approved methodology, including modeling or analyses that are not included within the scope of TORMIS, will not be approved unless adequately justified." e. "Page 10, Section 5.2: "The TORMIS analysis must include all SSCs that can adversely impact the tornado mitigation strategy, not just those SSCs that perform the functions that support the updated tornado mitigation strategy, and "significant damage" would apply to all of these SSCs (e.g., damage to SSCs that can result in a main steam line failure and excessive cooldown; damage to SSCs that can prevent operators from taking required actions). "The proposed use of TORMIS must be requested and justified via an LAR; the previous approval does not apply to the current situation. "The TORMIS LAR will have to address anything that is beyond the scope of TORMIS approval, such as modeling considerations and damage assessment of specific SSCs (to the extent that this is utilized)." f. "Issue No. 1, "Use of TORMIS": "The proposed use of TORMIS must be requested and justified via an LAR; the previous approval does not apply to the current situation." The TORMIS analysis must include all SSCs (safety-related and non-safety related) that can adversely impact the tornado mitigation strategy, not just those SSCs that perform the functions that support the updated tornado mitigation strategy; and "significant damage" would apply to all applicable SSCs in this regard (e.g., damage to SSCs that can result in a	a) All configurations described in the LAR will be validated for all three units prior to transmittal to the NRC. Additionally, the TORMIS analysis is being performed for all three units (although bounding arguments will be applied as possible) and any multi-unit interactions and interdependencies. b-g) Duke will describe how it intends to apply the TORMIS methodology in the LAR. Those components that are not or will not be protected from tornado missiles in accordance with UFSAR Class I or SSF missile criteria, will be evaluated with TORMIS. Attachment 2 of the Nov 30, 2006 letter describes the SSCs that are not designed to UFSAR missile criteria and the degree to which these SSCs are vulnerable. Attachment 2, Section 5.2 of the letter indicates that, in general, the analysis will collectively assess the ability of the SSF and PSW/HPI systems to meet the TORMIS acceptance criteria with respect to three functions 1) Secondary Side Decay Heat Removal 2) Reactor Coolant Pump Seal Injection and 3) Integrity of the Reactor Coolant System Pressure Boundary. The use of TORMIS was previously approved by the NRC for resolution of the secondary side decay heat removal GL-4 issue at ONS. The previously approved analysis is being extended to the reactor coolant pump seal injection and reactor coolant pressure boundary functions. There was no previous requirement to address the latter functions. However, TORMIS is being extended to these functions to add clarity and consistency to the LB. The analysis will be consistent with the five conditions (with the exception of the modified F-Scale) outlined in the SER's generic approval of the EPRI TORMIS methodology (dated Oct 28, 1983). An evaluation of secondary effects was not previously required for the resolution of the GL-4 issue or the IPEEE (see March 15, 2000 TER). Nonetheless, per Section 5.2 of Attachment 2 of the Nov 30, 2006 letter, ONS has committed to evaluating secondary effects in accordance with engineering judgment. Credit will be taken for activation of emergency response organizations and the assessment of plant conditions for any additional actions not specifically delineated in emergency operating procedures. As a general note, the Turbine Building contains approximately 4000 members in each building. As such, extensive damage by tornado missiles is not considered credible. h) TORMIS will be used to determine if any metal shielding will be added to protect SSF cabling leading into and through the CDTR and WPR. It will also be used to address an elevated trench on the north side of the SSF that is protected by a cantilevered section of the SSF facility. i) Initial TORMIS results indicate that the SSF will meet TORMIS acceptance criteria without reliance on PSW/HPI. Otherwise, these areas will be explicitly modeled by TORMIS since they support PSW/HPI operation	a) Agreed - Common Understanding, additional information/detail to be provided in a LAR. The LAR will describe configurations for all 3 units. A list of SSCs (including mechanical, electrical and I&C components) that will be addressed by the TORMIS analysis will be included in the LAR. b-g) Agreed - Common understanding - additional information to be provided in the LAR. Duke will request the use of TORMIS in the LAR. The LAR will describe the application of the TORMIS methodology at ONS and include a list of tornado missile targets that will be evaluated for primary effects. Duke will address secondary effects using a qualitative assessment or TORMIS, as appropriate, in the LAR *[a-g) Provided as Attachment 4 of the Tornado LAR dated June 26, 2008.]* h) Agreed - Common understanding, no further action required. i) Agreed - Common understanding, no further action required.

	NRC ISSUE	DUKE COMMENTS	Resolutions
	main steam line failure and excessive cooldown; damage to SSCs that can prevent operators from taking required actions)." The TORMIS LAR will have to address anything that is beyond the scope of TORMIS approval, such as modeling considerations (including "secondary effects" modeling) and damage assessment of specific SSCs (to the extent that this is credited).		
	g. "The TORMIS LAR will have to include a detailed listing of all SSCs that are included in the analysis, and address anything that is beyond the scope of the NRC staff's approval of TORMIS, such as modeling considerations and damage assessment of specific SSCs."		
	h. "Commitments 3T and 4T: To what extent is TORMIS being used for this analysis?"		
	i. "Page 9, Section 4: How will SSCs that are located in the cable spread, equipment, and control battery rooms be included within the scope of TORMIS?		
	j. "The Oconee Updated Final Safety Analysis Report (UFSAR) states that the electrical equipment and cable rooms were constructed to UFSAR Class 1 structure tornado wind, differential pressure (DP), and missile criteria. This is a valid part of the plant licensing basis and it is consistent with the Oconee design criteria. The fact that these rooms were not constructed in accordance with the UFSAR description does not necessarily mean that the UFSAR is in error, but this may well be another licensing-basis discrepancy. Therefore, a change to the UFSAR in this regard must be properly evaluated and addressed in accordance with 10 CFR 50.59 requirements."	j-k) In a September 15, 1986 letter, Duke stated that TORMIS analysis demonstrated that missile damage probability to all EFW and SSF ASW is less than the mean failure probability of 1E-6/rx-yr. The letter summarized the results of analyses assuming use of Station ASW. In the letter, Duke specifically noted that the Station ASW response time is 40 minutes, that the pressurizer safety valves (PSVs) will cycle to relieve pressure at 7 minutes and that the pressurizer will go water solid at 16 minutes. Additionally, the letter stated that "In light of the PRA result that the likelihood of EFW system failure due to tornado is very small, significant reliance on the Station ASW pump should not be considered necessary." Later, in a SER dated July 28, 1989, the NRC closed out the secondary side decay heat removal GL-4 issue. In the cover letter, the NRC stated that, "....the undamaged EFW system in one unit can supply feedwater to the steam generators in a unit with damaged EFW system cross-connections in the pump discharge piping." The cover letter concludes that, "Based on review of your probabilistic analysis, the staff concludes that the Oconee secondary side heat removal capability complies with the criterion for protection against tornadoes, and is therefore acceptable. This conclusion is <u>primarily based on the availability of the SSF ASW system</u>." For the purpose of tornado mitigation, the equipment and cable spread rooms support EFW and Station ASW. CLB depends on EFW from the unaffected unit but does not depend on Station ASW per the SER dated July 28, 1989 that resolved the secondary side decay heat removal GL-4 issue. The unaffected unit is not adversely impacted by the tornado. This will be addressed in accordance with 50.59 requirements.	j-k) Agreed - Common Understanding, additional information/detail to be provided in a LAR. *[j-k) Provided as Attachment 4 of the Tornado LAR dated June 26, 2008]*
	k. Second bullet: the design details specified in the UFSAR that indicates that the electrical equipment and cable rooms were constructed to UFSAR Class 1 structure tornado wind, DP, and missile criteria is considered plant licensing basis and a change to the UFSAR in this regard must be addressed accordingly in accordance with 10 CFR 50.59 requirements."		
	l. Page 9, Section 4: How will tornado missile capability to fail TB operating deck be addressed by the analysis?"	l) Given the construction and configuration of the Turbine Building operating deck, failure of the deck due to missiles is not considered credible.	l, n) Agreed - Common Understanding, additional information/detail to be provided in a LAR. The LAR will include an evaluation for the Turbine Building Structure and Operating Deck for damage due to tornado missiles that could significantly impact the tornado mitigation strategy. *[l, n) The aforementioned information was captured in the revised UFSAR pages shown in Attachment 3 of the Tornado LAR.]*
	m. "Page 3, first paragraph: the use of physical separation or physical barriers to protect one or more of the systems is not entirely accurate in that a TORMIS analysis will also be used."	m) The discussion related to physical separation is included in the Nov 30 2006 letter to demonstrate why the addition of the PSW/HPI system reduces risk relative to tornado missile damage in a subjective manner.	m) Agreed - Common Understanding, no further action required.
	n. "Page 5, Section 1.5: How will the TORMIS analysis evaluate turbine building structural failures that are sufficient to cause MS pipe or other high energy pipe failures, thereby compromising the tornado mitigation strategy?"	n) See item l	
	o. "Page 8, Section 3: what part of the CCW piping is not protected from tornado missiles, and is it being evaluated by TORMIS?"	o-p) A limited amount of CCW piping in the basement of the Turbine Building is not protected from tornado missiles. An evaluation will be performed to demonstrate that failure of this piping is not credible.	o-p) Agreed - Common Understanding, additional information/detail to be provided in a LAR. *[o-p) Additional information is provided in Duke Energy's Tornado LAR and subsequent RAI responses dated 5/6/10, 5/25/10, 6/24/10, and 8/31/10.]*
	p. "Vulnerable CCW piping should be included in the TORMIS analysis."		
	q. "Station modifications that provide reinforcement of an expansive portion of key structures to better withstand the effects of tornados - use of fiber reinforced polymer. What structures will be protected?"	q) The WPR and CDTR walls will be upgraded via FRP.	q) Agreed - Common Understanding, no further action required.
	r. "Commitment 5T: How will a tornado missile strike that compromises the fiber reinforced polymer be addressed in the TORMIS analysis?"	r) The FRP is being added as an enhancement for tornado wind and DP. It is not being credited for missile protection.	r) Agreed - Common Understanding, additional information/detail to be provided in a LAR. *[r) TORMIS modeling assumptions related to the West Pen Room walls are described in Section 5.4 in Attachment 4 of the Tornado LAR dated June 26, 2008.]*
	s. Page 5, Section 1.6: Is existing plant vital I&C power tornado protected; and are power sources for PSW/HPI vulnerable to tornado effects?"		

	NRC ISSUE	DUKE COMMENTS	Resolutions
		s) The new switchgear for PSW/HPI will be enclosed in a tornado protected enclosure. There is a limited vulnerability to tornado missiles in the equipment, control battery and cable spread rooms. The rooms are largely protected by adjacent structures. The SSF vital I&C are fully protected in the SSF facility and provide redundancy to the PSW/HPI system. In general, PSW/HPI instrumentation enters containment through the EPR and SSF enters containment through the WPR. Exceptions relate to PSW to the SG through the WPR (however, this only provides backup to the other PSW train in the EPR and SSF ASW in the WPR).	s) Agreed - Common Understanding, no further action required.
T2	COLD SHUTDOWN a. The PSW/HPI capability is the only means that can be relied upon for tornado and HELB mitigation beyond 72-hours, and it is the only means available for cooling down the Oconee units." b. "Fifth bullet: the licensing basis specifies the capability to place the Oconee units in cold shutdown condition and therefore, the licensee must be clear on what is being credited within the plant licensing basis in this regard such that the capability to achieve cold shutdown is assured." c. "Issue No. 2, "Cold Shutdown" • The plant licensing basis for both tornado and HELB includes the capability to achieve and maintain cold shutdown conditions. In the case of tornado, the station ASW system is credited for being able to maintain SSD for at least 30 days and the same capability should be provided by the PSW/HPI system. The submittal needs to explain how this capability will be assured, especially with respect to TS requirements. d. "Issue No. 2, "Cold Shutdown":" The licensing basis includes the capability to place the plant in cold shutdown and the mitigation strategy does not adequately address how this capability is assured relative to the extent of damage that can be experienced, recognizing that: a) it is critical to recover PSW/HPI within the 72-hour mission time of the SSF, and b) an assured source of cooling water that is good for at least 30-days is needed for the three Oconee units at the onset of tornado and HELB events." e. "Page 2, fourth paragraph: The manual alignment of the spent fuel pool (SFP) to HPI is a change to the original licensing basis that was not submitted for NRC review and approval." f. "Third bullet: the spent fuel pool (SFP) to the HPI pump flow path that was established by Duke after initial licensing of the Oconee units was not	a-d) ONS can find no evidence within the UFSAR or licensing correspondence with the NRC that would indicate that ONS has committed to achieve cold shutdown within specific time for tornado mitigation. Although the UFSAR does indicate that ONS has over 30 days of secondary heat removal inventory, it does not indicate that the SSF or other systems are capable of sustaining secondary heat removal without reliance on additional actions. The SSF mission time, for instance, is 72 hours in accordance with the SSF SER date April 28, 1983 and the GL-4 issue SER dated July 28, 1989. As indicated in Attachment 1, Commitment 7T, 5th bullet, ONS will enhance existing damage repair guidelines to extend the 72 hour safe shutdown capability of the SSF and to establish cold shutdown conditions. This enhanced capability will not be part of the LB. e-f) The SFP-HPI flow path will be removed by the LAR.	a-d) Specific aspects of the damage repair guidelines to extend the 72 hour safe shutdown capability of the SSF and to establish cold shutdown conditions will be described in the LAR. Agreed - Common understanding, additional information/detail to be provided in LAR. *[a-d) The aforementioned information is described in Enclosure 2, Section 4.2, "Damage Repair Guidelines and Procedures," of the Tornado LAR. Additional information is provided in T8 and Duke Energy's Tornado LAR RAI responses dated 5/6/10, 5/25/10, 6/24/10, and 8/31/10.]* e-f) Agreed - Common understanding, no further action required.

	NRC ISSUE	DUKE COMMENTS	Resolutions
	submitted for NRC review and approval."		
T3	<u>TECHNICAL SPECIFICATIONS</u> a. TS requirements that assure the operability and availability of structures, systems and components (SSCs) that are relied upon for the tornado and HELB mitigation strategies must be established, such as for the standby shutdown facility (SSF), the PSW/HPI system, the Unit 2 condenser circulating water (CCW) system, and for reactor coolant system leakage. b. "No mention of establishing a Technical Specification (TS) requirement pursuant to 10 CFR 50.36 even though the licensee recognizes that the PSW/HPI modifications will "significantly" improve overall plant risk." c. "Tornado and HELB events at Oconee represent at least the same level of risk as associated with design basis accidents (DBAs)." d. "The licensee proposes to rely upon the PSW/HPI system in conjunction with the SSF for tornado and HELB mitigation, and the licensee's TORMIS analysis is predicated on this. Therefore, TS requirements should be established not only to assure the operability of the PSW/HPI system, but also to assure that both the SSF and PSW/HPI systems are not both rendered inoperable at the same time." e. "The existing TS AOT must be reconsidered accordingly recognizing the new tornado and HELB mitigation functions." f. Operability of the water inventory for the SSF and PSW/HPI must be addressed. *The current SSF TS in this regard was based on the availability of* other systems such as EFW for performing the SSDHR function, which is not valid for the proposed tornado and TB HELB mitigation strategies. Furthermore, both the SSF and the PSW/HPI systems rely upon the same water supply and the licensee has not addressed how the water supply will be assured for both tornado and HELB mitigation." g. "First bullet: licensing basis clarity should be reflected in the Updated Final Safety Analysis Report (UFSAR), and TS requirements should be established in accordance with 10 CFR 50.36 requirements." h. "Issue No. 3, "Technical Specifications" A TS is required for the PSW/HPI system in accordance with 10 CFR 50.36(c)(2)(ii)(D). As stated on Page 3 of the November 30, 2006, submittal, Duke indicated that "the installation of a new PSW system and HPI system improvements will reduce reliance on the SSF by providing a system capable of independently establishing safe shutdown conditions, and thereby significantly improve overall plant risk." TS requirements were required for the SSF to assure its SSDHR function (even though other sources of SSDHR were considered to be available). The risk significance of the PSW/HPI system is on the same order of magnitude as the SSF and in this case, other sources of SSDHR may not be available." i. "Page 3, first bullet: Relative to the capability to power the submersible pump	a-l) See HELB, Issue H10	a-l) See HELB, Issue H10

	NRC ISSUE	DUKE COMMENTS	Resolutions
	by the PSW switchgear, what TS operability and surveillance requirements are appropriate?" j. "How is capability of submersible pump (powered by either SSF or PSW/HPI) assured by TS requirements?" k. "Page 3, first bullet: SSF and PSW will both use the Unit 2 condenser circulating water (CCW) inlet piping as a water source. How will availability of this water source be assured? The current SSF TS requirements did not include consideration of the proposed mitigation strategy and the current 45 day allowed outage time (AOT) for the Unit 2 CCW inlet is of concern. This needs to be reconsidered since the basis for the 45 day AOT is no longer valid, and the AOT should be limited based on tornado and HELB considerations recognizing that there are not other sources of water." l. How is water supply from the Unit 2 CCW assured to be available?		
T4	REACTOR COOLANT LETDOWN LINE a. "It is the NRC staff's position that the plant licensing basis for postulated failures of the letdown line includes consideration of single active failures, and postulated failures of the letdown lines for the Oconee units must be addressed accordingly."	a) Section 5.2 of Attachment 2 of the Nov 30, 2006 letter indicates that TORMIS will be used to evaluate the integrity of the reactor coolant system pressure boundary.	a) Agreed - Common Understanding, no further action required.
T5	OPERATOR ACTIONS a. "In order for the SSF to be credited, operators would have to be dispatched to the SSF during a tornado watch, not during a tornado warning as proposed. Once a tornado watch has been declared, the only question that remains is whether or not the tornado will touch down at Oconee or someplace else. If this is the one that hits Oconee, the SSF would not be accessible and it would be too late at this point to man the SSF until the tornado has passed." b. "Page 3, Section 1.2: Operators should be dispatched to the SSF during a tornado watch. A tornado warning means that the tornado has already touched down and it would be too late at this point to man the SSF if this turns out to be the tornado that hits the Oconee site. c. "Page 13, Section 7: The SSF should be manned upon declaration of a tornado watch. A tornado warning means that the tornado has already touched down and it would be too late at this point to man the SSF if this turns out to be the tornado that hits the Oconee site." d. "Why aren't PSW/HPI design criteria and time critical actions included similar to HELB commitments that were made?"	a-c) Response provided at Region II Pre-Decisional Conference Related to Unit 3 Control Room North Wall. Duke developed an event tree analysis to evaluate affects of tornado warning time. The ONS natural disaster procedure dispatches operators to the SSF upon receipt of tornado warning notification. The average response time is 3.6 minutes and the average travel time to SSF is 4 minutes. Based on National Weather Service (NWS) data, average tornado warning time is 13 minutes. Oconee believes there is minimal impact on overall SSF reliability. Note: Tornado warnings include identification via Doppler Radar. d) No comment.	a-c) Agreed - Common understanding, additional information/detail to be provided in LAR. The average warning time subsequent to issuance of a tornado warning and the average operator response time required to man the SSF subsequent to a tornado warning will be described in the LAR. d) Agreed - Common understanding, additional information/detail to be provided in LAR. *[a-d) Information on operator actions is provided in Duke Energy's tornado LAR (enclosure 2) and subsequent tornado RAI response dated 6/24/10.]*
T6	MSRV CYCLING a. "Page 3, Section 1.2: The discussion indicates that steam pressure may be controlled using the ADVs to limit the number of MSRV cycles. What number	a-c) See response to questions under HELB Issue H21.	See HELB Issue H21.

	NRC ISSUE	DUKE COMMENTS	Resolutions
	of MSRV cycles are considered acceptable and why? What assurance is there that the MSRV cycles will be limited accordingly?" b. "What limitations are required relative to reactor coolant system (RCS) leakage when using the MSRVs and atmospheric dump valves (ADVs) for steam generator (SG) pressure control and crediting the SSF, and what changes are necessary to the TS in this regard?" c. "Page 2, Section 1.1: What are the maximum number of cycles the MSRVs will experience and why doesn't one or more MSRV sticking open pose a problem?		
T7	**PSW DESIGN ISSUES** a. "Page 3, Section 1.3: what impact does tornado missile damage to the PSW piping in one penetration room have on the capability of PSW/HPI to perform its functions?" b. "Page 6, Section 2.3: what impact does damage to piping/electrical/I&C in one penetration room have on tornado mitigation capability of PSW/HPI? What is the effect on other units? Similarly for SSF?" c. "Page 8, Section 2.5: is any of the PSW I&C power not tornado protected?" d. "Page 9, Section 5.1: In addition to protecting the SSF and PSW/HPI components "that perform the functions," what about any support equipment that is needed (I&C, ADVs, RCP SI, etc.)?" e. "The installation of a new protected service water (PSW) system with switchgear capable of providing an assured source of electrical power to (among other things) the high pressure injection (HPI) pumps. Contrary to the information that was provided, this PSW/HPI system is not totally independent of the standby shutdown facility because they share the same water source." f. "Indicates that installation of PSW and HPI improvements will reduce reliance on the SSF by providing a system capable of independently establishing safe shutdown conditions, thereby significantly improving overall plant risk - not truly independent due to shared water source and west penetration room (WPR) vulnerabilities." g. "Sixth and seventh bullets: the commitment should specify that the PSW/HPI and related switchgear modifications will satisfy safety-related, seismic Category 1 criteria, and will be controlled and maintained in accordance with 10 CFR 50, Appendix B criteria." h. "Clarifications Required Concerning the Tornado and HELB Mitigation Strategies: "While the licensee seems to suggest that the PSW/HPI system will be installed as safety-related, seismic Category 1, and will be controlled in accordance with 10 CFR 50 Appendix B requirements, this needs to be clearly stated to assure that there is no misunderstanding."	a) The PSW supply to each SG is physically separated by containment. Either supply is adequate for secondary heat removal. SSF ASW also provides defense-in-depth. b) Preliminary TORMIS analysis indicates that SSF meets TORMIS criteria without reliance on PSW/HPI. As such, PSW/HPI provides margin to uncertainties. The description of physical separation provides additional qualitative assurance of the added value of PSW/HPI. c-d) See Item s under Issue T1. e-f) See HELB Issue, H21. g-h) See Common Issue, C1.	a-b) Agreed - Common Understanding, no further action required. c-d) See Item s under Issue T1. e-f) See HELB Issue, H21. g-h) See Common Issue, C1.

	NRC ISSUE	DUKE COMMENTS	Resolutions
T8	**CONCURRENT DAMAGE TO KHU/STATION SWITCHYARD** a. "Clarifications Required Concerning the Tornado Mitigation Strategy: "In addition to the specific tornado effects that the licensee referred to, the following additional considerations are also applicable: a complete loss of offsite power; and while the tornado is not assumed to cause tornado missile damage to the Keowee Hydro Units (KHU) and the Oconee units concurrently, it is assumed that both KHU and the Oconee units can be exposed to tornado force winds concurrently." b. In addition to the tornado effects that the licensee referred to, the following additional considerations also apply: the tornado effects include a complete loss of offsite power, and while the tornado is not assumed to cause tornado missile damage to KHU and the Oconee units concurrently, it is assumed that KHU is exposed to the tornado-force winds that would exist; and vice-versa for a tornado striking KHU. c. "Page 12, Section 6: The plant licensing basis includes the capability to achieve cold shutdown. The EDGs for other plants provide a 7-day capability to restore offsite power or to establish additional fuel oil inventory. The proposed 72-hour capability is not commensurate with the 7-day capability that is provided by other plants and the extensive damage that can be caused to the electrical distribution network in the vicinity of the Oconee station following a tornado strike at KHU could require well beyond 72-hours to restore a normal source of electrical power. Therefore, in order to assure the capability to maintain safe shutdown conditions and to subsequently achieve cold shutdown, the PSW/HPI mods should also include consideration of a tornado-protected capability to connect a temporary power source within 72-hours that is adequate for powering the PSW/HPI functions. Also note that there is no mention of how SFP makeup and boron addition will be accomplished over an extended period of time." d. "Page 2, first paragraph: In addition to the tornado effects that the licensee referred to, the following additional considerations are also applicable: a complete loss of offsite power; and while the tornado is not assumed to cause tornado missile damage to the Keowee Hydro Units (KHU) and the Oconee units concurrently, it is assumed that KHU is exposed to the tornado-force winds and vice-versa for a tornado striking KHU." e. Page 5, Section 1.6: • The capability to install (via a tornado protected connection) and use temporary power within 72 hours should also be considered since PSW/HPI is relied upon exclusively for maintaining SSD beyond 72-hours and for plant cooldown. f. Page 5, Third Bullet: This is taken out of context; the SSF auxiliary service water (ASW) system was specifically credited for mitigating the tornado that damages KHU with concurrent LOOP. Otherwise, the NRC SE accepted the licensee's analysis that credited station ASW and emergency feedwater (EFW) from the unaffected units." g. "Page 2, third paragraph: The Oconee current licensing basis (CLB) does not rely "extensively" on the SSF. This is only the case for when the tornado strikes KHU resulting in a loss of power to the Oconee station. Otherwise, Station ASW and EFW of the other unaffected units was relied upon in the CLB."	a-e) The original and current UFSAR refers to physically separated power supplies that include KHU and the station switch yard. As an enhancement, an alternate power supply is being installed from the Lee CT 100 KV line to the PSW protected switchgear to further reduce the probability of a loss of power to the PSW/HPI system in the event of a coincident strike of the Station and Keowee. The probability of coincident tornado damage to the Station and Keowee was previously assessed in the ONS IPEEE. See commitment 7T last bullet Attachment 1 and Sections 1.6 and 2.5 of Nov 30, 2006 letter. Cold shutdown aspects discussed under Issue T2. Spent fuel pool makeup is currently addressed by SSF operational procedures. f-h) See Items j-k under Issue T1 Note: In conclusion, from a licensing perspective, the PSW system will replace the EFW system from the unaffected unit. In addition, the tornado event will be conservatively considered a 3 unit versus a single unit event.	a-e) Agreed - Common understanding, additional information/detail to be provided in LAR concerning the Lee 100 kV line and the zone of influence of the tornado path. The LAR will include information regarding the Lee CT 100 KV line. See July 12, 2006 NRC letter, Enclosure 2, Item 5. *[a-d) Additional information is also provided in Duke Energy's Tornado LAR (enclosure 2, Revised licensing basis - emergency power) and subsequent RAI responses dated 5/6/10, 5/25/10, 6/24/10, and 8/31/10.]* *[e) The use of temporary electrical power beyond the SSF's credited 72 hours was considered but not proposed in the overall mitigation response submitted to the Staff in the Tornado LAR.]* f-h) See Items j-k under Issue T1.

	NRC ISSUE	DUKE COMMENTS	Resolutions
	h. "*Issue No. 2, "Cold Shutdown" : The CLB relies upon SSF for providing* secondary side decay heat removal (SSDHR) only when the tornado takes out KHU; otherwise station ASW is relied upon for long-term cooling."		

Response Documentation for:

Item 62

3.7 PLANT SYSTEMS

3.7.10 Protected Service Water (PSW) System

LCO 3.7.10 The PSW System shall be OPERABLE as follows:

a. The mechanical portion of the PSW System is OPERABLE,
b. The electrical portion of the PSW System is OPERABLE including a power supply to the PSW switchgear from either:
   1) The KHU Protected Service Water Power Path or,
   2) The 100 kV Central Tie Switchyard overhead line.

Deleted: KHU underground path

APPLICABILITY: MODES 1, 2, and 3
MODE 4 when steam generators are relied upon for heat removal.

ACTIONS

NOTE

LCO 3.0.4 is not applicable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. PSW System is INOPERABLE. AND SSF Systems are OPERABLE.	A.1 Restore PSW System to OPERABLE status.	30 days
B. PSW System is INOPERABLE. AND SSF Systems are INOPERABLE.	B.1 Restore PSW System to OPERABLE status.	7 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Condition A or B not met when the PSW System is INOPERABLE due to maintenance.	C.1 Restore to OPERABLE status.	——NOTE—— Not to exceed 45 days cumulative per calendar year ———— 45 days from discovery of initial inoperability.
D. Required Action and associated Completion Time of Condition C not met. OR Required Action and associated Completion Time of Condition A or B not met for reasons other than Condition C.	D.1 Be in MODE 3. AND D.2 Be in MODE 4.	12 hours 84 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.10.1	*Verify required PSW battery terminal voltage is ≥ 125 VDC on float charge.*	*7 days*
SR 3.7.10.2	Verify that the KHU Protected Service Water Path can be aligned to and power the PSW electrical system.	90 days
SR 3.7.10.3	Verify that the developed head of the PSW pump at the flow test point is greater than or equal to the required developed head.	In accordance with the In-Service Testing (IST) Program
SR 3.7.10.4	Verify for required PSW battery that the cells, cell plates and racks show no visual indication of physical damage or abnormal deterioration that could degrade battery performance.	12 months

Deleted: KHU underground

(continued)

BASES (continued)

LCO (continued)

- RCS and Reactor Vessel Head high point vent valves
- PSW electrical system from either the KHU Protected Service Water Path or 13.8 kV overhead power paths to support secondary side decay heat removal (SSDHR) and reactor coolant make-up (RCMU) functions.
- A required number of 125 VDC Vital I&C Normal Battery Chargers (Ref.: TS 3.8.3, DC Sources – Operating).

Deleted: KHU underground

PSW system dedicated instrumentation and controls located in each main control room:

- Two (2) high flow controllers (one per SG).
- Two (2) low flow controllers (one per SG).
- One (1) flow indicator (per SG).
- Two (2) SG header isolation valves (one per SG header).
- Two (2) HPI System power transfer switches per unit.
- Power transfer switches to HPI valves needed to align the BWST to the HPI pumps.

APPLICABILITY

In MODES 1, 2, and 3, the PSW System is required to be OPERABLE and to function in the event that all normal and emergency feedwater systems are lost. In MODE 4, with RCS temperature above 212 °F, the PSW System may be used for heat removal via the steam generators. In MODE 4, the steam generators are used for heat removal unless this function is being performed by the Low Pressure Injection System. In MODE 4 steam generators are relied upon for heat removal whenever an RCS loop is required to be OPERABLE or operating to satisfy LCO 3.4.6, "RCS Loops – Mode 4."

In MODES 5 and 6, the steam generators are not used for SSDHR and the PSW System is not required.

ACTIONS

The exception for LCO 3.0.4, provided in the Note of the Actions, permits entry into MODES 1, 2, 3 or 4 with the PSW not OPERABLE. This is acceptable because the PSW is not required to support normal operation of the facility or to mitigate a design basis accident.

source for the HPI pump or alternatively, the pump can be manually aligned to a SFP should the BWST be unavailable. For the SSF RCMU pump, water from the SFPs is used and RCS inventory is managed from the SSF CR.

As described in UFSAR Sections 3.3.2 and 3.8.4.3, certain structures that house systems and components necessary to achieve SSD have been constructed to withstand the effects of a tornado (wind, ΔP, and missiles). Other specific structures necessary to achieve SSD, while designed to withstand wind and ΔP, were evaluated for the probability of a damaging missile strike using risk analysis. An example of the latter includes the WPR walls. Longer-term recovery actions beyond the current SSF 72 hour mission time are not addressed in the CLB.

Revised LB

The overall objective of the revised tornado LB is to utilize the SSF for SSDHR and RCMU following a loss of all normal and emergency systems which usually provide these functions. The SSF systems can maintain all three units in a safe shutdown condition, i.e., Mode 3 with average RCS temperature ≥ 525 °F (unless the initiating event causes the unit(s) to be driven to a lower temperature[15]) for up to 72 hours while damage control measures are completed to restore any unavailable PSW System equipment needed to cooldown the units to ~250 °F. This mission time is in accordance with the SSF CLB. The ~250 °F temperature is the lowest that can be attained using the steam generators (SGs) for cooldown.

The existing Station ASW system will be replaced with a new PSW system and be capable of cooling the units to approximately 250 °F where they would remain until additional damage control measures can facilitate cooldown to cold shutdown (CSD)[16] conditions. *Although the SSF or the new PSW systems both have the capability to* restore SSDHR and RCMU for all three units, the PSW system is not fully protected from a severe tornado and as such, is not credited in the revised LB within the first 72 hours after a tornado.

The revised tornado LB assumes that a tornado strikes the plant site during full power operation and disables the emergency and non-emergency electrical buses located in the TB resulting in a station blackout condition. A further assumption is that due to the approximate ½ mile separation between the KHUs and the Oconee Nuclear Units, a tornado missile will not cause concurrent damage to both the KHUs and the Oconee Nuclear Units. As added margin, alternate power (primary power is from the KHU Protected Service Water Path) to the new PSW System is provided from the Central Tie

Deleted: KHU underground feed

[15] TORMIS results (Attachment 4) have shown that the probability of a damaging missile striking the MS lines upstream of the new MSIVs to be extremely low and as such, there is reasonable assurance that a rapid RCS cooldown transient resulting in RCS temperatures falling below the SSF threshold temperature, to be remote. Therefore, tornado induced MS line breaks are not postulated in the revised tornado mitigation strategy.

[16] Cold shutdown is Mode 5 with RCS temperature < 200 °F.

Emergency Power

Current LB

A protected diesel generator supplies power to the SSF and its support systems for up to 72 hours. The SSF power supply system is designed to provide normal and independent emergency sources of AC and DC electrical power to their associated electrical distribution systems and various support systems. The SSF diesel generator would only be operated in the event where normal power systems are unavailable. Manual operator action is required to actuate the SSF.

Power to the Station ASW switchgear, located below grade in the AB, is supplied from the KHU Protected Service Water Path. This switchgear can power a Station ASW pump and one HPI pump per unit. The structures that comprise the KHUs are the Powerhouse, Power and Penstock Tunnels, Spillway, Service Bay Substructure, Breaker Vault, and Intake Structure. The KHUs are Class 2 structures which have not been designed and built to resist tornado loads. At ONS, the wind loading of a Class 2 structure is 95 miles per hour.

Deleted: KHU underground feed

Revised LB

A protected diesel generator supplies power to the SSF and its support systems for up to 72 hours. The SSF power supply system is designed to provide normal and independent emergency sources of AC and DC electrical power to their associated electrical distribution systems and various support systems. The SSF diesel generator would only be operated in the event where normal power systems are unavailable. Manual operator action is required to actuate the SSF systems.

The Station ASW switchgear will be replaced with the PSW System switchgear located in a new tornado-protected PSW building. New power cables will be routed from the KHUs to the PSW building through an underground path. Alternate power to the PSW System switchgear will be provided by a new transformer connected to the existing 100 kV transmission line that receives power from the Central Tie Switchyard located approximately 8 miles from the plant. This new power path is strategically located on the opposite side of the station from the KHUs which reduces the chance of concurrent tornado damage to both power sources.

The new tap-off portion from the 100 kV line will not adversely affect the operation of the station's CT5 emergency transformer. Any fault that occurs on this new portion of line will be isolated from the 100 kV line with either the high side circuit switcher or the low side breaker installed at the PSW substation. The PSW switchgear will also provide a backup power supply to the SSF via an underground path as additional defense-in-depth. An electrical diagram displaying the revised power arrangement for the SSF and PSW Systems and the location of the CT5 transformer is shown on Figure 1.

Although the power lines from the alternate offsite power supply to the PSW switchgear

4.5 Conclusions

Implementation of the revised tornado LB and the related commitments will clarify and, in some cases, revise the ONS CLB to address issues raised by the NRC and collectively enhance the station's overall design, safety and risk margin. The safety margins afforded by the revised tornado LB will be improved by:

- Verification that the SSF is the assured means of achieving SSD conditions for one, two, or all three units,
- Replacing the single-unit low-head Station ASW system with a 3-unit high-head PSW System that:
  - is controllable from the main CRs,
  - can be placed into service quickly to minimize inventory loss from the PZR safety valves,
  - increases assurance that natural circulation will be established and maintained,
  - can be powered from either the KHU Protected Service Water Path or alternatively, the 100 kV Central substation path located on the opposite side of the station from the KHUs which reduces the chance of concurrent tornado damage to both emergency power sources.
- Physically protecting the BWST to the extent necessary, to assure that the tank and flowpath are available following a tornado,
- Installation of MSIVs for each unit's main steam header,
- The elimination of several time-critical manual operator actions outside of the CRs including:
  - ADV operation for SG depressurization,
  - Alignment of the Station ASW valves and breakers,
  - Connection of the Station ASW switchgear power supply to an HPI pump and,
  - Alignment of the SFP to HPI flow path.

Deleted: KHU underground

Tab 3

Unit 3 LAR (incl. HELB Report data for Units 1, 2, and 3)

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June 29, 2009

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

Subject: Duke Energy Carolinas, LLC
Oconee Nuclear Station, Unit 3
Renewed Facility Operating License Number DPR-55
Docket Number 50-287
"Proposed License Amendment Request to Revise the Oconee Nuclear Station Current Licensing Basis for High Energy Line Break Events Outside of the Containment Building,"
License Amendment Request No. 2008-007

References:

1. Letter to Mr. James Dyer, Director, Office of Nuclear Reactor Regulation, from Henry B. Barron, Group Vice President and Chief Nuclear Officer, Nuclear Generation, Duke Energy Corporation, "Tornado/HELB Mitigation Strategies and Regulatory Commitments," dated November 30, 2006.
2. Letter from Leonard N. Olshan, Project Manager, Plant Licensing Branch II-1, Division of Operating Reactor Licensing, Office of Nuclear Reactor Regulation, "Summary of March 5, 2007, Meeting to Discuss the November 30, 2006, Letter Regarding Oconee High-Energy Line Break (HELB) and Tornado Mitigation Strategies," dated March 28, 2007.
3. Letter from Leonard N. Olshan, Project Manager, Plant Licensing Branch II-1, Division of Operating Reactor Licensing, Office of Nuclear Reactor Regulation, "Summary of March 20, 2007, Meeting to Discuss Oconee High-Energy Line Break (HELB) Mitigation Strategy," dated April 3, 2007.
4. Letter from Timothy J. McGinty, Deputy Director, Division of Operating Reactor Licensing, USNRC Office of Nuclear Reactor Regulation, to Bruce H. Hamilton, Oconee Nuclear Station, Units 1, 2, and 3 (Oconee) – Tornado and High-Energy Line Break (HELB) Mitigation Strategies, dated May 15, 2007.
5. Letter to the U. S. Nuclear Regulatory Commission from Henry B. Barron, Group Vice President and Chief Nuclear Officer, Nuclear Generation, Duke Energy Corporation, "Revision to Tornado/HELB Mitigation Strategies and Regulatory Commitments," dated January 25, 2008.

6. Letter to the U. S. Nuclear Regulatory Commission from David Baxter, Vice President, Oconee Nuclear Station, Duke Energy Corporation, "Proposed License Amendment Request to Revise the Oconee Nuclear Station Current Licensing Basis for HELB events outside of the Containment Buildings; License Amendment Request No. 2008-005," dated June 26, 2008.

7. Letter to the U. S. Nuclear Regulatory Commission from Dave Baxter, Vice President, Oconee Nuclear Station, Duke Energy Corporation, Revision to Tornado/HELB Strategies and Regulatory Commitments," dated November 18, 2008.

8. Letter to the U. S. Nuclear Regulatory Commission from Dave Baxter, Vice President, Oconee Nuclear Station, Duke Energy Corporation, "Proposed License Amendment Request to Revise the Oconee Nuclear Station Current Licensing Basis for HELB Events outside of the Containment Building – Unit 2; License Amendment Request No. 2008-006," dated December 22, 2008.

In accordance with 10 CFR 50.90, Duke Energy Carolinas, LLC, (Duke) proposes to amend Renewed Facility Operating License No. DPR-55. This License Amendment Request (LAR) is a continuation of the information sent in the June 26, 2008, LAR 2008-005 (Reference 6) and in the December 22, 2008, LAR 2008-006 (Reference 8). This LAR applies to Unit 3 of the Oconee Nuclear Station (ONS). All non-unit specific information, all generic commitments, and proposed generic modifications submitted in LARs 2008-005 and 2008-006, also apply to this LAR. This LAR will result in a complete revision of the ONS Current Licensing Basis (CLB) in regard to mitigating High Energy Line Break (HELB) events occurring outside of containment for Unit 3.

The proposed changes are the result of an extensive and comprehensive HELB analysis and include several plant modifications necessary to support the revised HELB Licensing Basis (LB). Included in the proposed changes are the Unit 3 sections of the ONS HELB Report, ONDS-351, Revision 2, and "Analysis of Postulated High Energy Line Breaks (HELBs) Outside of Containment." For this LAR, the ONS Unit 3 portion of the existing HELB Report, MDS Report No. OS-73.2, dated April 25, 1973, and its supplements dated June 22, 1973, and March 12, 1974, respectively, are superseded by Oconee Report ONDS-351, Revision 2. However, the existing HELB report will remain credited until the ONDS-351 Revision 2 report, has been fully implemented, including the incorporation of the proposed modifications.

The enclosed Revision 2 to ONDS-351 includes the Safe Shutdown Analyses for HELBs postulated on the Unit 3 High Energy Piping lines and the Unit 3 specific information for other sections of the HELB report. Those analyses in this revision of ONDS-351 credit normal plant equipment, the Standby Shutdown Facility (SSF), and the new Protected Service Water (PSW) system to achieve safe shutdown. The report also credits the proposed use of the Main Steam Isolation Valves (MSIV), whenever a postulated break is determined to affect the Main Steam pressure boundary and the safe shutdown strategy relies on the SSF. The scenarios using the

SSF/MSIVs for Main Steam Line breaks are described in Section 7.0 and the MSIVs are described in Section 3.0 of ONDS-351.

This LAR includes a supplementary list of regulatory commitments in Attachment 1 made as a result of the analyses of the Unit 3 postulated HELBs. This supplementary list is in addition to those commitments made in References 5, 6, and 8, and partially revised in Reference 7. Attachment 2 contains the list of the sections of ONDS-351 to be added or replaced. An identification of the reason for each change is also provided in this attachment. Attachments 3 and 4 contain the changes to the UFSAR pages and the Technical Specification (TS) pages. These changes are necessary to include the applicability of Unit 3.

A technical evaluation of the proposed changes is contained in Enclosure 1. Enclosure 2 contains Revision 2 of ONDS-351. This revision of the report incorporates the HELB interactions resulting from postulated breaks on Unit 3 high energy piping, adds the MSIV description, and includes the use of the SSF/MSIV for postulated Main Steam Line HELBs. Revision 2 of ONDS-351 also updates all other text sections of the report to remove any inconsistencies amongst the unit evaluations and correct any identified minor errors, typos, and omissions. The only portions of the HELB Report that are not being reissued are those portions of the Units 1 and 2 tables and figures referenced in sections 4.1, 4.2, 5.1, and 5.2, which do not require revision, and hence are identical to their transmittal in the previous LAR submittals (References 6 and 8).

As described herein, the revised ONS HELB LB is based on the plant configuration that will exist after implementation of modifications to the site as described in various correspondence with the Staff and in this LAR (Ref.: 1, 2, 3, 4, 5, 6, 7, and 8). Accordingly, implementation of the revised HELB LB will be integrated with the completion of those associated plant modifications. As part of modification implementation, certain emergency procedures, pertaining to HELB mitigation and plant safe shutdown, will be revised to include the use of the new systems and methodology.

As noted in the commitment table, the completion for some of the proposed HELB modifications will be contingent upon the staff's approval of the revised HELB methodology. Duke requests approval of this amendment by July 2010, with an extended implementation period in accordance with the listing of commitments given in Attachment 1, References 5, 6, and 8.

The specific actions that Duke will be implementing have been selected and prioritized based upon a thorough assessment of operational risk and safety benefits as well as regulatory considerations and resource requirements. These actions will require a significant investment of resources by Duke and are intended to resolve outstanding HELB LB issues. Duke believes these actions collectively represent the most appropriate use of resources to enhance safety and resolve regulatory issues. Implementation of the revised HELB LB and the related commitments will revise the HELB CLB to address issues raised by the NRC and to collectively enhance the station's overall design, safety and risk margin.

In accordance with Duke administrative procedures that implement the Quality Assurance Program Topical Report, these proposed changes have been reviewed and approved by the Plant Operations Review Committee and Nuclear Safety Review Board. A copy of this LAR is being sent to the State of South Carolina in accordance with 10 CFR 50.91 requirements.

Inquiries on this proposed amendment request should be directed to Stephen C. Newman of the Oconee Regulatory Compliance Group at (864) 873-4388.

I declare under penalty of perjury that the foregoing is true and correct. Executed on June 29, 2009.

Sincerely,

Dave Baxter, Vice President,
Oconee Nuclear Station

Enclosures:

1. Evaluation of Proposed Changes
2. ONDS-351, "Analysis of Postulated High Energy Line Breaks (HELBs) Outside of Containment," Rev. 2

Attachments:

1. List of Regulatory Commitments
2. List of sections added or revised in ONDS-351, Rev. 2, and the reason for the change(s).
3. Marked-up pages: UFSAR and Technical Specification Bases
4. Reprinted pages: UFSAR and Technical Specification Bases.

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ENCLOSURE 1

EVALUATION OF PROPOSED CHANGES

Subject: Proposed License Amendment Request to Revise the Oconee Nuclear Station Current Licensing Basis for High Energy Line Break Events Outside of the Containment Building – Unit 3.

1. SUMMARY DESCRIPTION
2. BACKGROUND/CIRCUMSTANCES
3. DETAILED DESCRIPTION OF PROPOSED CHANGES
4. TECHNICAL EVALUATION
5. REGULATORY EVALUATION
6. ENVIRONMENTAL CONSIDERATION

1 SUMMARY DESCRIPTION

In accordance with 10CFR 50.90, Duke Energy Carolinas, LLC (Duke) proposes to amend Renewed Facility Operating License Number DPR-55. This License Amendment Request (LAR) will result in a complete revision of the Oconee Nuclear Site (ONS) Current Licensing Basis (CLB) with regard to High Energy Line Breaks (HELBs) events outside of the containment for Unit 3.

The LAR also includes several plant modifications and revisions to the Updated Final Safety Analysis Report (UFSAR) necessary to support the revised HELB Licensing Basis (LB) for Unit 3.

The Unit 3 changes proposed in this LAR include changes to the current HELB methodology and mitigation strategy as documented in ONDS-351, Rev. 2. This includes the results of the completed analysis for Unit 3 HELBs including the descriptions of the station modifications that have been or will be made as a result of this reanalysis. ONDS-351, Rev. 2 has been written with the HELB interaction analysis and pathway to a safe shutdown condition based upon the station configuration following the completion of these modifications.

ONDS-351, Revision 2 provides a complete re-evaluation of postulated HELBs and describes the 'as modified' station configuration for the newly identified HELBs on Unit 3. This document, once fully implemented, will supersede in its entirety, the current HELB analysis provided in the original MDS OS-73.2 Report dated April 25, 1973, and its supplements dated June 22, 1973, and March 12, 1974, respectively, and establish a new licensing basis for future HELB considerations. Section 9 of Enclosure 2 identifies and describes the proposed modifications that have been or will be made in order to provide a pathway to a Safe Shutdown condition for postulated HELBs. Additional specific HELB mitigation strategies, regulatory commitments, and responses have been previously provided to the Staff in Duke's November 30, 2006, letter[1] (last revised on November 18, 2008[2]), the Unit 1 HELB LAR submitted on June 26, 2008[3], and the Unit 2 HELB LAR submitted on December 22, 2008[4].

The analysis of effects resulting from postulated piping breaks outside of containment was

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[1] Letter to Mr. James Dyer, Director, Office of Nuclear Reactor Regulation, from Henry B. Barron, Group Vice President and Chief Nuclear Officer, Nuclear Generation, Duke Energy Corporation, "Tornado/HELB Mitigation Strategies and Regulatory Commitments," dated November 30, 2006.

[2] Letter to the U. S. Nuclear Regulatory Commission from Dave Baxter, Site Vice President, Oconee Nuclear Station, "Revision to Tornado/HELB Mitigation Strategies and Regulatory Commitments," dated November 18, 2008.

[3] Letter to the U. S, Nuclear Regulatory Commission from Dave Baxter, Vice President, Oconee Nuclear Station, Duke Energy Corporation, "Proposed Licensing amendment Request to Revise the Oconee Nuclear Station current Licensing Basis for HELB Events outside of the Containment Buildings; Licensing amendment Request No. 2008-005," dated June 26, 2008.

[4] Letter to the U. S, Nuclear Regulatory Commission from Dave Baxter, Vice President, Oconee Nuclear Station, Duke Energy Corporation, "Proposed Licensing amendment Request to Revise the Oconee Nuclear Station current Licensing Basis for HELB Events outside of the Containment Building – Unit 2; Licensing Amendment Request No. 2008-006," dated December 26, 2008.

originally documented in Duke Power MDS Report No. OS-73.2[5] (including Supplements 1[6] and 2[7]). Revision 2 of ONDS-351, "Analysis of Postulated High Energy Line Breaks (HELBs) Outside of Containment" contains the updated methodology and proposed strategies. As a result, the original HELB Report remains credited until the ONDS-351 report is fully completed including the incorporation of proposed modifications.

The enclosed HELB Report revision includes Safe Shutdown Analyses for HELBs postulated on the Unit 3 High Energy Lines. Those analyses credit normal plant equipment, the *Standby Shutdown Facility (SSF), and the new Protected Service Water (PSW) System to* achieve safe shutdown. The report also credits the use of the Main Steam Isolation Valves (MSIV), whenever a postulated HELB is determined to affect the Main Steam pressure boundary and the Safe Shutdown strategy relies on the SSF. The safety analysis, which describes the use of the MSIV/SSF for achieving and maintaining a Safe Shutdown condition and the description of the MSIVs is provided in Sections 7.0 and 3.0 of ONDS-351, Rev. 2, respectively.

2 BACKGROUND/CIRCUMSTANCES

As ONS construction was nearing completion, the Atomic Energy Commission (AEC) issued a letter from A. Giambusso (AEC), Deputy Director for Reactor Projects Directorate of Licensing, to Duke Power Company (now Duke Energy Carolinas, LLC), dated December 15, 1972[8]. The "Giambusso Letter" required licensees to address the consequences of pipe ruptures outside containment and submit their analyses to the AEC for review. Due to the specific guidance in the letter, the applicable events were identified as "High Energy Line Break" (HELB) events. The "Giambusso Letter" was amended by an errata sheet provided in a letter from A. Schwencer (AEC), Chief Pressurized Water Reactors Branch No. 4 Directorate of Licensing, to Duke Power Company, dated January 17, 1973[9] (the "Schwencer letter").

Duke's evaluations of postulated pipe ruptures outside containment were documented in MDS Report No. OS-73.2 dated April 25, 1973, with Supplement 1 to the report dated June 22, 1973 and Supplement 2 to the report dated March 12, 1974. The final report is referred to herein as "current HELB report," "MDS Report" and/or "OS-73.2."

The MDS report was incorporated into the ONS license application by reference. It was subsequently approved and accepted by the AEC. "Safety Evaluation prepared by the Directorate of Licensing related to the Oconee Nuclear Station, Units 2 and 3," (referred to

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5 MDS Report No. OS-73.2, Analysis of Effeets Resulting from Postulated Piping Breaks Outside Containment for Oconce Nuclear Station, Units 1, 2, & 3, prepared by Duke Power company, dated April 25, 1973.

6 MDS Report No. OS-73.2, Supplement 1, Analysis of Effects Resulting from Postulated Piping Breaks Outside Containment for Oconee Nuclear Station, Units 1, 2, & 3, prepared by Duke Power eompany, dated June 22, 1973.

7 MDS Report No. OS-73.2, Supplement 2, Analysis of Effects Resulting from Postulated Piping Breaks Outside Containment for Oconee Nuclear Station, Units 1, 2, & 3, prepared by Duke Power company, dated March 12, 1974.

8 Letter dated 15 December 1972 from A. Giambusso (AEC) to A. C. Thies (DPC) transmitting the "General Information Required for Consideration of the Effects of a Piping system Break Outside Containment."

9 Clarification Letter (related to the 15 December 1972 letter), dated 17 January 1973, from A. Sehweneer (AEC) to A. C. Thies (DPC)

herein as "the SER") dated July 6, 1973[10], was issued as part of the initial licensing of Units 2 and 3. SER Section 7.1.11 "High-energy Line Rupture External to the Reactor Building" addressed the MDS report, and Attachment E of the SER repeated the NRC HELB criteria, as amended by the Schwencer letter. The following is extracted from Section 7.1.11:

"The basic criteria require that:

(1) Protection be provided for equipment necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming a concurrent and unrelated single active failure of protected equipment, from all effects resulting from ruptures in pipes carrying high-energy fluid, up to and including a double-ended rupture of such pipes, where the temperature and pressure conditions of the fluid exceed 200 °F and 275 psig. Breaks should be assumed to occur in those locations specified in the "pipe whip criteria." The rupture effects on equipment to be considered include pipe whip, structural (including the effects of jet impingement) and environmental.

(2) Protection be provided for equipment necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming a concurrent and unrelated single active failure of protected equipment, from the environmental and structural effects (including the effects of jet impingement) resulting from a single open crack at the most adverse location in pipes carrying high-energy fluid routed in the vicinity of this equipment, where the temperature and pressure conditions of the fluid exceed 200 °F and 275 psig. The size of the cracks should be assumed to be 1/2 the pipe diameter in length and 1/2 the wall thickness in width....

<u>Staff Evaluation and Conclusion</u>

The staff has evaluated the assessment performed by the applicant and has concluded that the applicant has analyzed the facilities in a manner consistent with the intent of the criteria and guidelines provided by the staff. The staff agrees with the applicant's selection of pipe failure locations and concludes that all required accident situations have been addressed appropriately by the applicant.

Furthermore the staff has evaluated the analytical methods and assumptions used in the applicant's analyses and find them acceptable and concurs with the proposed plant modifications and the criteria to be used in their designs."

Several years after approval of the MDS report and initial licensing of ONS, the SSF was built. The SSF provides additional defense-in-depth protection to achieve and maintain Mode 3 with an average Reactor Coolant System temperature ≥ 525 °F following postulated fire, sabotage, or flooding events.

The SSF Reactor Coolant Make-up (RCMU) system is the SSF sub-system designed and credited to supply RC pump seal injection flow in the event that the High Pressure Injection (HPI), the normal make up system, becomes inoperable when a Unit's RCS temperature is >

[10] Safety Evaluation Report (From AEC) for Oconee Units 2 & 3, July 6, 1973.

250 °F. It can recover RCS volume shrinkage caused by cooling the RCS to Mode 3 with an average Reactor Coolant temperature ≥ 525 °F. However, the SSF Reactor Coolant Make-up System is not credited for events, such as LOCA, which result in significant loss of RCS inventory. The SSF Auxiliary Service Water System (ASW) is the SSF sub-system credited as the backup to the Feedwater (FDW) and Emergency Feedwater (EFW) systems.

A 1998 Duke HELB self-assessment revealed issues with the original OS-73.2 report, and as a result, Duke decided to fully revalidate and revise the HELB CLB. In late 1999, Duke initiated a project to determine scope of these CLB revision efforts[11]. This HELB CLB revision effort is being completed on a unit by unit basis with ONS Unit 1 (ONS-1) completed first and the remaining units thereafter.

3 DETAILED DESCRIPTION OF PROPOSED CHANGES

Specifically, NRC approval is requested for: (1) the revised HELB LB and Revision 2 of ONDS-351 that provides the Unit 3 High Energy Line Interaction Analysis, (2) the associated Unit 3 station modifications to certain structures, systems, and components (SSCs) to better withstand the effects of postulated HELBs, and (3) the UFSAR revisions associated with including Unit 3 into the applicability of the revised HELB LB. The proposed Unit 3 modifications are described in section 9.0 of ONDS-351, Rev. 2.

4 TECHNICAL EVALUATION

The information necessary for the technical evaluation is discussed in Revision 2 of ONDS-351. The following sections of ONDS-351 are submitted to address the Unit 3 postulated HELBs:

- Section 1.3.3 - Identification of Unit 3 specific calculations
- Section 2.0 - Identification of criteria for determining the high energy lines, break locations and types, and the evaluation criteria for shutdown sequences and interactions
- Section 3.3 – Description of MSIVs
- Section 6.1 – Identification of the high energy lines, high energy line boundaries, break locations, and break types for Unit 3
- Section 6.2 – Analysis of Unit 3 HELBs with Unit 3 SSCs
- Section 6.3 – Analysis of Unit 3 HELBs with Units 1 and 2 SSCs
- Section 7.0 – Analysis of Main Steam Line, Main Feedwater Line, and Letdown Line Breaks; inclusion of SSF/MSIV in Safe Shutdown scenarios
- Section 8.0 - Applicable regulatory criteria specific to Unit 3

[11] Letter from W. R. McCollum, Jr., Vice President, Oconee Nuclear Station, to the Nuclear Regulatory Commission, "High-Energy Line Break outside Reactor Building Methodology," dated July 3, 2002.

- Section 9.0 – Identification of modifications to SSCs resulting from Unit 3 HELBs

With the implementation of the methodology and associated modifications described in ONDS-351, Rev. 2, a pathway to achieving and maintaining a safe shutdown condition will exist for postulated Unit 3 HELBs. In addition, attainment of a cold shutdown condition will be possible for postulated Unit 3 HELBs although repairs may be necessary for some equipment.

5 TECHNICAL EVALUATION

5.1 SIGNIFICANT HAZARDS CONSIDERATION

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

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

   Response: No.

   Justification: The Unit 3 changes proposed in this LAR include revisions to the current HELB methodology and mitigation strategy as documented in a new HELB report. This report provides the completed analysis for ONS HELBs including the descriptions of the station modifications that have been or will be made as a result of this comprehensive HELB reanalysis.

   The modifications associated with the revised HELB LB will be designed and installed in accordance with applicable quality standards such that the likelihood of failure of new or modified SSCs will not initiate failures, malfunctions, or inadvertent operations of existing accident mitigating SSCs, such as the KHUs, SSF, HPI, or the Central Tie Switchyard 100 kV alternate power systems. For Turbine Building HELBs that could adversely affect equipment needed to stabilize and cooldown the units, the addition of the PSW System provides added assurances that safe shutdown can be readily established and maintained beyond the 72-hour SSF mission time.

   In conclusion, the changes will collectively enhance the station's overall design, safety, and risk margin; therefore, the proposed change does not involve a significant increase in the probability or consequence of an accident previously evaluated.

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

   Response: No.

   Justification: The proposed modifications address potential adverse consequences from a HELB outside of containment. These modifications will be designed and installed in compliance with applicable quality standards such that there are reasonable assurances that they will neither introduce nor cause new failure mechanisms, malfunctions or accident initiators not already considered in the current HELB design and licensing basis.

The overall effect of the changes to the HELB LB is considered an enhancement to the station's ability to achieve safe and cold shut down following a damaging HELB; therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   Response: No.

   Justification: The revised HELB LB will collectively enhance the station's overall design, safety, risk margin, and the station's ability to mitigate a HELB event; therefore, the proposed change does not involve a significant reduction in a margin of safety.

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

5.2 APPLICABLE REGULATORY REQUIREMENTS/CRITERIA

5.2.1 UFSAR 10.4.7.3.2 (EFW Response Following a HELB) describes the mitigation strategies for HELBs resulting in a loss of TC, TD, and TE switchgear, Feedwater/Main Steam line breaks causing loss of SG pressure boundary, and other Condensate/Feedwater line breaks that result in a loss of condenser hotwell inventory.

5.2.2 UFSAR 3.6.1 (Postulated Piping Failures in Fluid Systems Inside and Outside Containment), denotes that the analysis of effects resulting from postulated piping breaks outside containment is contained in Duke Power MDS Report No. OS-73.2, dated April 25, 1973, including revision through Supplement 2. Additionally stated is that an evaluation of potential non-safety grade control system interactions during design basis high energy line break accidents is contained in the Duke Power/Babcock and Wilcox Report dated October 5, 1979.

5.3 PRECEDENT

HELB methodology-related license amendment requests have been previously submitted and approved by the Staff for the D. C. Cook, Clinton, Crystal River-3, Comanche Peak, South Texas Project, and Oconee Nuclear Stations.

5.4 CONCLUSION

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

6 ENVIRONMENTAL CONSIDERATION

Duke has evaluated this license amendment request against the criteria for identification of licensing and regulatory actions requiring environmental assessment in accordance with 10CFR 51.21. Duke has determined that this license amendment request meets the criteria for a categorical exclusion as set forth in 10CFR 51.22(c) (9). This determination is based on the fact that this change is being proposed as an amendment to a license issued pursuant to 10CFR 50 that changes a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10CFR 20, or that changes an inspection or a surveillance requirement, and the amendment meets the following specific criteria:

(i) The amendment involves no significant hazards consideration.

As demonstrated in Section 5.1, this proposed amendment does not involve a significant hazards consideration.

(ii) There is no significant change in the types or significant increase in the amounts of any effluent that may be released offsite.

The ONS design requirement is that systems, structures, or components (SSCs) required for shutting down and maintaining the units in a shutdown condition will not fail as a result of damage caused by a HELB outside of containment. The change proposed in this amendment request will enhance and clarify the overall HELB LB to better ensure that this design requirement is maintained. Since the principal barriers to the release of radioactive materials are not modified or affected by this change, no significant increases in the amounts of any effluent that could be released offsite will occur as a result of this proposed change.

(iii) There is no significant increase in individual or cumulative occupational radiation exposure.

Because the principal barriers to the release of radioactive materials are not modified or affected by this change, there will be no significant increase in individual or cumulative occupational radiation exposure resulting from this change.

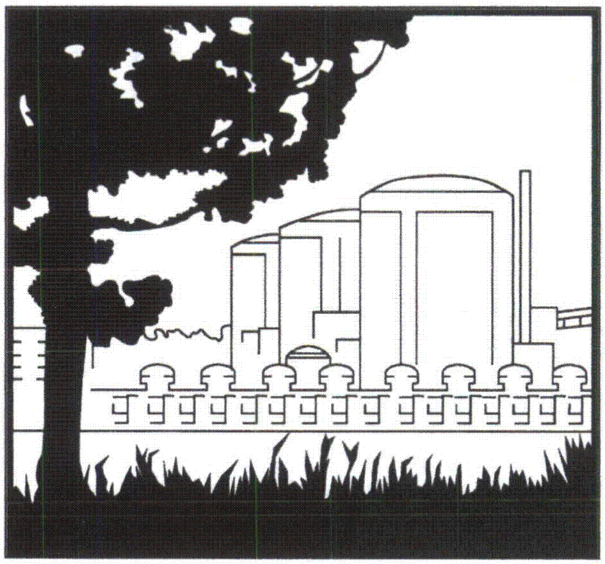
ENCLOSURE 2

ONDS-351, "ANALYSIS OF POSTULATED HIGH ENERGY LINE BREAKS (HELBS) OUTSIDE OF CONTAINMENT"

(REVISION 2)

Duke Energy®

OCONEE NUCLEAR STATION
UNITS 1, 2, & 3



ANALYSIS OF POSTULATED HIGH ENERGY LINE BREAKS (HELBs) OUTSIDE OF CONTAINMENT

ONDS -351

(Revision 2)

(File Number: OS-292.A)

QA Condition 1

CERTIFICATION SHEET

Revision Number: 2

Originated By: Patrick M. Donnelly Date: 6/24/2009
Patrick M Donnelly

Originated By: Allen D. Park Date: 6/24/2009
Allen D Park

Checked By: Timothy D. Brown Date: 6/24/2009
Timothy D Brown

Approved By: G K McAninch Date: 6-24-09
George K Mc Aninch

REVISION DOCUMENTATION SHEET

Revision Number	Revision Description
0	Original Release
1	Revised the Executive Summary, the Table of Contents, the List of Tables, the List of Figures, and Sections 1.0, 5.0, 8.0, 9.0 and 10.0 to include the results of the Unit 2 HELB Analyses
2	Revised document to include the Unit 3 HELBs, HELB Safety Analysis Results, and MSIV description: updated document per latest information and HELB bases; Added Section 6.0 & revised the remaining sections, tables, & figures

Executive Summary

This Design Study, ONDS-351, Rev.2 , "Analysis of Postulated High Energy Line Breaks (HELBs) Outside of Containment" is the culmination of the Oconee Nuclear Station Units 1, 2, and 3 HELB Outside Containment Reconstitution Project. This design study will completely replace the previous HELB report, OS-73.2 (File No. OS-27B), "Analysis of Effects Resulting From Postulated Piping Breaks Outside Containment for Oconee Nuclear Station, Units 1, 2, & 3." The study will serve as the new design basis for Units 1, 2, and 3 and be incorporated into the licensing basis. As did the previous HELB report, the design study will be included as part of the Oconee Updated Final Safety Analysis Report (UFSAR) by reference in UFSAR Section 3.6.1, "Postulated Piping Failures in Fluid Systems Inside and Outside Containment."

The study evaluates the postulated Units 1, 2, and 3 high energy line breaks outside containment. The rules, to which the breaks were postulated and the basis for their evaluation, reside in the December 15, 1972, letter from A. Giambusso, Deputy Director for Reactor Projects, Directorate of Licensing, Atomic Energy Commission (AEC), amended by the January 17, 1973, letter from A. Schwencer, Chief, Pressurized Water Reactors Branch No. 4, Directorate of Licensing, AEC. In cases where Oconee Nuclear Station sought clarifications and or deviations to the rules promulgated in those letters, Duke held extensive meetings with the NRC to establish a position. The agreements established in those meetings were provided in a letter from Duke Power Company LLC d/b/a Duke Energy Carolinas, LLC, (Duke) to the Nuclear Regulatory Commission (NRC), dated November 30, 2006, as amended on January 25, 2008.

The study provides a comprehensive evaluation of the potential Units 1, 2, and 3 high energy line breaks outside containment. The potential effects have been analyzed, the documentation of which is provided in referenced Oconee plant calculations. The evaluations considered potential high energy line break interactions with the Auxiliary Building and Turbine Building structures, with multiple cable trays that carry cables that provide power and/or signal power to components necessary to reach a Safe Shutdown condition, as well as direct effects to other mechanical and electrical systems and components necessary to achieve and maintain a Safe Shutdown condition. Additionally, the ability to reach the Cold Shutdown Condition following the break was evaluated. The study considered potential effects, such as resulting Auxiliary Building and Turbine Building flooding, and potential multi-unit blackouts, not considered in the original report.

The study includes Safe Shutdown analyses for high energy line breaks postulated throughout the plant. Those analyses credit normal plant equipment, the Standby Shutdown Facility (SSF), and the new Protected Service Water System to achieve Safe Shutdown. Revision 2 of the report includes the evaluation of breaks that may compromise the Main Steam pressure boundary and the function of the Main Steam Isolation Valves (MSIVs) to mitigate the effects of the break based on safety analysis work that has been completed. These analyses demonstrate that safe shutdown can be attained following breaks that compromise the Main Steam pressure boundary. The inputs, assumptions, and results of these safety analyses will be used in the detailed design of the MSIVs. The design of the MSIVs remains in progress at the date of this revision to the report. Details of the design and how the final design meets the requirements assumed in the safety analyses will be communicated to the staff in a future License Amendment Request (LAR).

The study includes a description of modifications credited in order to meet the new HELB design basis. Some of those modifications, such as the East Penetration Room Flood Protection have been installed and are fully operational. The designs of certain portions of the new Protected Service Water (PSW) System have been completed, while other portions of the system remain in progress. Implementation activities have begun on those sections of the system where the design is complete. Finally, the report provides descriptions of other modifications that are either in the conceptual or design stage.

With the implementation of the modifications described in this study, a pathway to achieving and maintaining a Safe Shutdown condition will exist for any HELB postulated in Units 1, 2, and 3. In addition, attainment of the Cold Shutdown Condition will be possible for any HELB postulated in Units 1, 2, and 3. However, in some cases, credit will be taken for repairs to potentially affected equipment to achieve the Cold Shutdown Condition.

Duke has worked closely with the NRC staff on formulating a comprehensive HELB design basis. This new HELB design basis, along with the modifications noted above will significantly improve the overall risk profile for the Oconee Nuclear Station.

ANALYSIS OF POSTULATED HIGH ENERGY LINE BREAKS (HELBs) OUTSIDE OF CONTAINMENT

OCONEE NUCLEAR STATION, UNITS 1, 2, & 3

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1.0 INTRODUCTION

1.1 Background

In December 1972 the (then) Atomic Energy Commission (AEC) sent to the Duke Power Company (DPC) a request for information (References 10.1.1 & 10.1.2) concerning postulated piping breaks on High Energy (HE) lines outside of the containment (Reactor Building) at the Oconee Nuclear Station (ONS). In response to this request DPC provided to the AEC the analysis of the HE line configuration at the ONS. This analysis was documented in MDS Report No OS-73.2 (Reference 10.3.1) and Supplements 1 and 2 (References 10.3.2 & 10.3.3). The 1973 document included the High Energy Line Break (HELB) criteria, station design methodologies and protection requirements for mitigating postulated HELBs outside the containment. Based upon the information provided in the 1973 document and the supplements, an ONS Unit 2 & Unit 3 Safety Evaluation Report was received from the AEC on July 6, 1973, in which the AEC evaluated the assessment performed by DPC and concluded that DPC has analyzed the ONS in a manner consistent with the intent of the criteria and guidelines provided by the AEC (Reference 10.3.4).

In 1998 Duke Energy Generation Services (Duke) performed an assessment (Reference 10.3.5) that identified issues with the original HELB analysis performed in 1973. As a result of this assessment Duke initiated a project to update the original HELB work. This initiative was communicated to the Nuclear Regulatory Commission (NRC) Region II management during a January 26, 1999 management meeting. The primary objective of this initiative was to revalidate and update the original ONS HELB design basis for the present station configuration. This document represents the results of that initiative (project) and provides the completed analysis for HELBs at the ONS. Included in this document are the descriptions of the station modifications that have been made or will be made as a result of performing this comprehensive HELB analysis. <u>As such, this document has been written with the HELB interaction analysis and pathway to a Safe Shutdown/Cold Shutdown Condition identification based upon the station configuration following the completion of these HELB modifications, as described in Section 9.0 of this report.</u>

1.2 Purpose & Methodology

The purpose of this document and the descriptions of the evaluations and analyses contained within are to document the HELB configuration for the ONS and to provide a comprehensive, updated strategy for mitigating the adverse interactions caused by these postulated HELBs. Since this document provides a complete re-evaluation of the postulated HELBs in the ONS and describes the (as modified) ONS configuration for the identified HELBs, it supersedes the analysis provided in the original 1973 ONS HELB analysis (References 10.3.1 to 10.3.3) and establishes a new basis for future HELB considerations. The original HELB report, OS-73.2 (Reference 10.3.1), will still be used as a reference for definitions and historical information. In addition, this document identifies and describes the station modifications that have been made or will be made, in order to provide a pathway to a Safe Shutdown condition for any postulated HELB in any Unit and to describe these pathways, based upon the station configuration following the completion of these modifications.

The analyses in this document have been accomplished by using a systematic, step-by-step program of identification, evaluation, and documentation. These steps in the HELB program for the ONS are as follows:

1. Identification of the High Energy (HE) systems, the HE lines, and the boundaries of the HE lines on each of those systems.
2. Identification of the postulated HELB locations and break types on each of the HE lines.
3. Determination of the equipment and systems in the ONS Units, which could be utilized to mitigate the postulated HELBs. (This step is the identification of the generalized pathway to Safe Shutdown/Cold Shutdown and the listing of the components needed for each phase of the Shutdown Sequence.)
4. Identification of the targets (structures, systems, and components) of each postulated HELB based upon the results of field inspections.
5. Determination of the Shutdown Equipment that was undamaged by the postulated HELB and can be used for the HELB mitigation and the Shutdown of the station. This step is based upon the identification of the targets and the impact of the postulated HELBs on those targets.
6. Identification and recommendation of station physical and/or procedural changes that are necessary to eliminate the deficiency for any postulated HELBs, where event mitigation and/or Safe Shutdown are not achievable.

Documentation, in the form of station calculations, has been generated for each step of the process. These documents are controlled, and they form the basis of the information contained herein.

1.3 Calculations Generated

The following ONS calculations have been generated, in order to support the development and analysis of the HELB configuration for the ONS. For each calculation identified the number, title and a brief description of the purpose and information in the calculation is provided.

1.3.1 Calculations Applicable to Unit 1

The following calculations apply to Unit 1:

OSC-7516.01 – High Energy Line Break Stress Evaluation (ONS-Unit 1)

This calculation documented the systems & piping sections outside of the containment that contained high energy fluid. The calculation also identified and documented the HE piping line break locations (Reference 10.2.2)

OSC-7516.02 - ONS – Unit 1 Pipe Rupture Evaluations HELB Outside Containment Plant Walkdowns

This calculation documents the results of the plant walk downs. These walk downs inspected the postulated HELB locations and identified the potential interactions with Shutdown Structures, Systems, and Components. The interactions were determined based upon the information in

Calculations OSC-8089.01 and OSC-8089.02 (References 10.2.4 & 10.2.15), which identified the mechanical and electrical Shutdown Equipment and Calculation OSC-7516.01, which identified the HELB locations. These results of the walk downs were documented by break location (Reference 10.2.6)

<u>OSC-7516.03 - Unit 1 HELB Turbine Building Structural Interactions Evaluations</u>

This calculation determined the pipe whip and/or jet impingement loads imposed on structural members from postulated HELBs in the Turbine Building. The information in this calculation was used to determine if the postulated HELBs caused structural members to fail (Reference 10.2.7).

<u>OSC-7516.04- Safe Shutdown Equipment Damage Assessment for HELB</u>

This calculation (Reference 10.2.8) evaluated the information that was generated in Calculations OSC- 8385, OSC-7516.01 & OSC-7516.02 (References 10.2.1, 10.2.2 & 10.2.6). It identified HE piping sections that could be excluded as high energy lines and as a result eliminated the postulated break locations on those sections. This calculation also identified the break locations that had no interactions with Shutdown Equipment. Finally, this calculation identified the damage to Shutdown Equipment and evaluated whether a pathway to cold shutdown existed, based upon the information provided in Calculation 7516.02.

<u>OSC-7516.06 – TB STRUDL Model for Detailed HELB Evaluations</u>

This calculation (Reference 10.2.9) determined the dead weight loading on the structural members in the Turbine Building. It was performed, so that a determination could be made as to the state of stress that would exist in these structural members, if they were subjected to additional loads resulting from the direct interactions (pipe whip/ jet impingement) of postulated HELBs. The results of this calculation were used as input to Calculation OSC-7516.03 (Reference 10.2.7).

<u>OSC-7516.07 – ONS Unit 1 – HELB Cable Interactions – Failure Modes and Effects</u>

This calculation (Reference 10.2.10) provided the documentation of the effects of the HELB interactions with identified electrical cables. The calculation identified the Shutdown Components affected and how these components were affected by the HELB interactions. This information was used to establish the HELB interaction evaluation results documented in calculation OSC-7516.08 (Reference 10.2.11)

<u>OSC-7516.08 – Failure Modes and Effects Analysis for HELB</u>

This calculation documented the results of the interaction analysis, which was conducted to determine if a pathway to safe shutdown existed for postulated HELBs. This calculation used the information in Calculations OSC-7516.04 (Reference 10.2.8) and OSC-7516.07 (Reference 10.2.10) as input to determine if a pathway to Safe Shutdown/Cold Shutdown existed (Reference 10.2.11).

OSC-7516.09 – ONS Unit 1 Collateral Damage to Systems, Structures, and Components Located in the Turbine Building from postulated HELBs

This calculation evaluates and documents the potential damage to Shutdown Equipment resulting from HELB interactions with Turbine Building structural members that result in a structural failure. The results of Calculation OSC-7516.03 (Reference 10.2.7) and the data in Calculations OSC-8089.01 and OSC-8089.02 (References 10.2.4 & 10.2.15) are used as the bases for generating the data in this calculation (Reference 10.2.12).

OSC-7516.10 – Collateral Damage Assessment for Structural Interactions for Postulated HELBs

This calculation documents the results of the potential damage to Shutdown Equipment resulting from the collateral damage documented in Calculation OSC-7516.09 (References 10.2.12). The calculation evaluates, whether a pathway to a Safe Shutdown condition and the Cold Shutdown Condition exist for each of the identified structural interactions and their associated collateral damage (Reference 10.2.13).

1.3.2 Calculations Applicable to Unit 2

OSC-7517.01 – ONS Unit 2 High Energy Line Break Stress Evaluation

This calculation documented the systems & piping sections outside of the containment that contained high energy fluid. The calculation also identified and documented the HE piping line break locations (Reference 10.2.39)

OSC-7517.02 - ONS – Unit 2 Pipe Rupture Evaluations HELB Outside Containment Plant Walkdowns

This calculation documents the results of the plant walk downs. These walk downs inspected the postulated HELB locations and identified the potential interactions with Shutdown Structures, Systems, and Components. The interactions were determined based upon the information in Calculations OSC-8089.01 and OSC-8089.02 (References 10.2.4 & 10.2.15), which identified the mechanical and electrical Shutdown Equipment and Calculation OSC-7517.01, which identified the HELB locations. These results of the walk downs were documented by break location (Reference 10.2.40)

OSC-7517.03 - Unit 2 HELB Turbine Building Structural Interactions Evaluations

This calculation determined the pipe whip and/or jet impingement loads imposed on structural members from postulated HELBs in the Turbine Building. The information in this calculation was used to determine if the postulated HELBs caused structural members to fail (Reference 10.2.41).

OSC-7517.04- Safe Shutdown Equipment Damage Assessment for HELB

This calculation (Reference 10.2.42) evaluated the information that was generated in Calculations OSC- 8385, OSC-7517.01 & OSC-7517.02 (References 10.2.1, 10.2.39 & 10.2.40). It identified

HE piping sections that could be excluded as high energy lines and as a result eliminated the postulated break locations on those sections. This calculation also identified the break locations that had no interactions with Shutdown Equipment. Finally, this calculation identified the damage to Shutdown Equipment and evaluated whether a pathway to cold shutdown existed, based upon the information provided in Calculation OSC-7517.02.

<u>OSC-7517.06 – TB STRUDL Model for Detailed HELB Evaluations</u>

This calculation (Reference 10.2.43) determined the dead weight loading on the structural members in the Turbine Building. It was performed, so that a determination could be made as to the state of stress that would exist in these structural members, if they were subjected to additional loads resulting from the direct interactions (pipe whip/ jet impingement) of postulated HELBs. The results of this calculation were used as input to Calculation OSC-7517.03 (Reference 10.2.41).

<u>OSC-7517.07 – ONS Unit 2 HELB Cable Interactions – Failure Modes and Effects</u>

This calculation (Reference 10.2.44) provided the documentation of the effects of the HELB interactions with identified electrical cables. The calculation identified the Shutdown Components affected and how these components were affected by the HELB interactions. This information was used to establish the HELB interaction evaluation results documented in calculation OSC-7517.08 (Reference 10.2.45)

<u>OSC-7517.08 – Failure Modes and Effects Analysis for HELB</u>

This calculation documented the results of the interaction analysis, which was conducted to determine if a pathway to safe shutdown existed for postulated HELBs. This calculation used the information in Calculations OSC-7517.04 (Reference 10.2.42) and OSC-7517.07 (Reference 10.2.44) as input to determine if a pathway to Safe Shutdown/Cold Shutdown existed (Reference 10.2.45).

<u>OSC-7517.09 – ONS Unit 2 Collateral Damage to Systems, Structures, and Components Located in the Turbine Building from postulated HELBs</u>

This calculation evaluates and documents the potential damage to Shutdown Equipment resulting from HELB interactions with Turbine Building structural members that result in a structural failure. The results of Calculation OSC-7517.03 (Reference 10.2.41) and the data in Calculations OSC-8089.01 and OSC-8089.02 (References 10.2.4 & 10.2.15) are used as the bases for generating the data in this calculation (Reference 10.2.46).

<u>OSC-7517.10 – Collateral Damage Assessment for Structural Interactions for Postulated HELBs</u>

This calculation documents the results of the potential damage to Shutdown Equipment resulting from the collateral damage documented in Calculation OSC-7517.09 (References 10.2.46). The calculation evaluates, whether a pathway to a Safe Shutdown condition and the Cold Shutdown Condition exist for each of the identified structural interactions and their associated collateral damage (Reference 10.2.47).

OSC-9554 – Ventilation Equipment Room 520 HELB Analysis

This calculation determined the time history of a postulated Plant Heating System HELB in the Equipment Ventilation Room 520 with the objective of determining the peak pressure differential in the room created by the postulated HELB (Reference 10.2.51).

1.3.3 Calculations Applicable to Unit 3

The following calculations apply to Unit 3:

OSC-7518.01 – ONS Unit 3 High Energy Line Break Stress Evaluation

This calculation documented the systems & piping sections outside of the containment that contained high energy fluid. The calculation also identified and documented the HE piping line break locations (Reference 10.2.52)

OSC-7518.02 - ONS – Unit 3 Pipe Rupture Evaluations HELB Outside Containment Plant Walkdowns

This calculation documents the results of the plant walk downs. These walk downs inspected the postulated HELB locations and identified the potential interactions with Shutdown Structures, Systems, and Components. The interactions were determined based upon the information in Calculations OSC-8089.01 and OSC-8089.02 (References 10.2.4 & 10.2.15), which identified the mechanical and electrical Shutdown Equipment and Calculation OSC-7518.01, which identified the HELB locations. These results of the walk downs were documented by break location (Reference 10.2.53)

OSC-7518.03 - Unit 3 HELB Turbine Building Structural Interactions Evaluations

This calculation determined the pipe whip and/or jet impingement loads imposed on structural members from postulated HELBs in the Turbine Building. The information in this calculation was used to determine if the postulated HELBs caused structural members to fail (Reference 10.2.54).

OSC-7518.04- Safe Shutdown Equipment Damage Assessment for HELB

This calculation (Reference 10.2.55) evaluated the information that was generated in Calculations OSC- 8385, OSC-7518.01 & OSC-7518.02 (References 10.2.1, 10.2.52 & 10.2.53). It identified HE piping sections that could be excluded as high energy lines and as a result eliminated the postulated break locations on those sections. This calculation also identified the break locations that had no interactions with Shutdown Equipment. Finally, this calculation identified the damage to Shutdown Equipment and evaluated whether a pathway to cold shutdown existed, based upon the information provided in Calculation 7518.02.

OSC-7518.06 – TB STRUDL Model for Detailed HELB Evaluations

This calculation (Reference 10.2.56) determined the dead weight loading on the structural members in the Turbine Building. It was performed, so that a determination could be made as to the state of stress that would exist in these structural members, if they were subjected to additional loads resulting from the direct interactions (pipe whip/ jet impingement) of postulated HELBs. The results of this calculation were used as input to Calculation OSC-7518.03 (Reference 10.2.54).

OSC-7518.07 – ONS Unit 3 HELB Cable Interactions – Failure Modes and Effects

This calculation (Reference 10.2.57) provided the documentation of the effects of the HELB interactions with identified electrical cables. The calculation identified the Shutdown Components affected and how these components were affected by the HELB interactions. This information was used to establish the HELB interaction evaluation results documented in calculation OSC-7518.08 (Reference 10.2.58)

OSC-7518.08 – Failure Modes and Effects Analysis for HELB

This calculation documented the results of the interaction analysis, which was conducted to determine if a pathway to safe shutdown existed for postulated HELBs. This calculation used the information in Calculations OSC-7518.04 (Reference 10.2.55) and OSC-7518.07 (Reference 10.2.57) as input to determine if a pathway to Safe Shutdown/Cold Shutdown existed (Reference 10.2.58).

OSC-7518.09 – ONS Unit 3 Collateral Damage to Systems, Structures, and Components Located in the Turbine Building from postulated HELBs

This calculation evaluates and documents the potential damage to Shutdown Equipment resulting from HELB interactions with Turbine Building structural members that result in a structural failure. The results of Calculation OSC-7518.03 (Reference 10.2.54) and the data in Calculations OSC-8089.01 and OSC-8089.02 (References 10.2.4 & 10.2.15) are used as the bases for generating the data in this calculation (Reference 10.2.59).

OSC-7518.10 – Collateral Damage Assessment for Structural Interactions for Postulated HELBs

This calculation documents the results of the potential damage to Shutdown Equipment resulting from the collateral damage documented in Calculation OSC-7518.09 (References 10.2.59). The calculation evaluates, whether a pathway to a Safe Shutdown condition and the Cold Shutdown Condition exist for each of the identified structural interactions and their associated collateral damage (Reference 10.2.60).

OSC-9656 – Determination and Documentation of Input Parameters for Ventilation Equipment Room 565 HELB Analysis

This calculation (Reference 10.2.61) determined the free volume of Ventilation Equipment Room 565 and the vent area of the room. In addition, the calculation documented other physical quantities needed to assess the impact of Plant Heating System HELBs in Room 565. The information in this calculation is used in Calculation OSC-9693 (Reference 10.2.62).

OSC-9693 – Ventilation Equipment Room 565 – HELB Analysis

This calculation determined the time history of a postulated Plant Heating System HELB in the Equipment Ventilation Room 565 with the objective of determining the peak pressure differential in the room created by the postulated HELB (Reference 10.2.62). This calculation provides input data for calculation OSC-9603 (Reference 10.2.50).

1.3.4 Calculations Applicable to all Three (3) ONS Units

The following calculations apply to the HELB configuration of all three (3) ONS Units:

OSC-2034 – East Penetration Rooms Low Pressure Blowout Panels

This calculation determined the pressure necessary to cause the Blowout Panels in the East Penetration Room (EPR) to rupture as a result of postulated MSLBs in the EPR, based on the as-built configuration of the panels. The calculation also determined the size of the vent open area (Reference 10.2.14).

OSC-6182 – Main Steam Line Break (MSLB) Event Mitigation Requirements

This calculation was revised for the HELB analysis to include the electrical equipment that will be required to function to mitigate postulated MS Line HELBs in the EPR. Specifically, the calculation listed the electrical equipment that would be subjected to a harsh environment created by these postulated HELBs (Reference 10.2.5)

OSC-8036 – Flow From FDW (Feedwater) Line Crack Into Penetration Room

This calculation was generated to provide input for further analysis of HELBs in the East Penetration Rooms. The calculation determined the size of the Main Feedwater Line Critical Crack, the enthalpy of the exiting water from the crack, and the mass flow rate of the water exiting the crack area (Reference 10.2.29).

OSC-8089.01 – High Energy Line Break (HELB) Safe Shutdown Target List (SSTL)

This calculation identified the mechanical and electrical equipment that may be used to establish a Safe Shutdown condition and cool down the unit to the Cold Shutdown Condition (Reference 10.2.4).

OSC-8089.02 – High Energy Line Break (HELB) Safe Shutdown Target List (SSTL) Pressure Boundary Piping

This calculation (Reference 10.2.15) identified and documented the required piping portions and boundaries of the mechanical Shutdown Systems needed to support a unit shutdown. This information was used to identify HELB interactions that are documented in Calculations OSC-7516.02, OSC-7517.02, & OSC-7518.02 (References 10.2.6, 10.2.40, & 10.2.53).

<u>OSC-8104 – High Energy Line Breaks in the Penetration Room</u>

This calculation generated the pressure time histories for Postulated HELBs in the EPR and West Penetration Room (WPR). The calculation analyzed the double-ended MSLB, the double-ended MFLB, and the Feedwater Line Critical Crack (Reference 10.2.3).

<u>OSC-8265 – East Penetration Room Flooding from Feedwater Line Breaks</u>

This calculation determined the maximum height of the flood in the EPR resulting from a postulated MFLB. The information in this calculation was used as input to determine the size of the EPR Flood Outlet Device and the height of the EPR flood retention barrier (Reference 10.2.16).

<u>OSC-8385 – Normal Operating Conditions for High Energy Line Break (HELB) Analysis</u>

This calculation determined the normal operating temperature and pressure of the fluid in the High Energy piping in the ONS. Actual plant operating data was used to establish these parameters. The calculation also identified various sections of the high energy piping that could be excluded because of these normal operating temperature and pressure conditions (Reference 10.2.1).

<u>OSC-8505 – Oconee HELB EQ Analysis for Penetration Rooms</u>

This calculation (Reference 10.2.17) provided the documentation necessary to validate the equipment qualification of the Shutdown Electrical Components in the EPR and West Penetration Room (WPR). The calculation provided the qualification evaluations of this equipment for the new environmental profiles generated by postulated HELBs in the EPR and the WPR and documented in Calculation OSC-8104 (Reference 10.2.3). The calculation was later revised to include the equipment identified in Appendix "A" of Calculation OSC-6182 (Reference 10.2.5).

<u>OSC-8556 – High Energy Line Break Safe Shutdown Component Analysis</u>

This calculation (Reference 10.2.18) identified and documented the cables that were impacted by postulated HELBs. The information in this calculation was used as the basis for the assessments conducted in Calculations OSC-7516.07, OSC-7517.07, & OSC-7518.07 (References 10.2.10, 10.2.44, & 10.2.57).

<u>OSC-8602 – Evaluation of East Penetration (Room) Structural Components</u>

This calculation determined the capabilities of various doors, walls, floors, and ceilings of the EPR (and other areas affected by the pressure) as a result of internal pressurization loading on these structural elements from a postulated MSLB (Reference 10.2.19).

OSC-9076 – HPI HELB at Penetration 9 – Flow Rate into the East Penetration Room

This calculation determined the flow from HPI HELBs in the EPR. The calculation determined the flow rate for both the charging line HELB and the RCP Seal Injection Line HELB (Reference 10.2.20).

OSC-9082 – HELB at HPI Pump – Pump Operating Point & Time to Flood

This calculation determined the flow rate out of a postulated HELB at the discharge nozzle of an HPI Pump. The flow rate for both an operating and non-operating HPI Pump was determined. The calculation also determined the minimum time interval before the HPI Pump Room would flood to an unacceptable level (Reference 10.2.21).

OSC-9204 – Determination of Flooding Rates and Flood Heights in the Turbine Building as a Result of Postulated High Energy Line Breaks

This calculation documented the postulated HELBs in the Turbine Building that could damage the CCW and/or the LPSW Systems. It also generated conservative calculations of the maximum flood heights and the time interval to reach these maximum flood heights that would result from these postulated HELBs. The calculation also determined if the maximum acceptable flood height was exceeded and the time interval from the start of the HELB to when the maximum acceptable flood level was exceeded (Reference 10.2.22).

OSC-9212 – Temperature Response of the Control Room Complex for Postulated HELBs in the East Penetration Room Using RT^3

This calculation determined the time history temperature profile for the Control Complex for a postulated MSLB or MFLB in the EPR. The temperature time history for the Main Control Room, the Cable Spreading Room, and the Electrical Equipment Room was determined (Reference 10.2.23).

OSC-9213 – Determination of Flooding Rates and Flood Heights in the East & West Penetration Rooms

This calculation determined the flooding parameters for various HPI HELBs in the EPR and the WPR. Specifically, this calculation determined the time interval when water would flood up to the Flood Outlet Device curb and the maximum height in the EPR. This calculation also determined the time interval before the flood water would reach the top of the flood barrier on the emergency exit in the WPR (Reference 10.2.24).

OSC-9276 – HELB Letdown Line Break Analysis

This calculation determined the mass flow rate out of the postulated HELB on the Letdown Line at Penetration #6 in the EPR. The calculation generated the time history of the break mass flow rate (Reference 10.2.25).

OSC-9281 – Radiological Dose Consequences of a HELB Letdown Line Break Event

This calculation generated the dose consequences resulting from the postulated Letdown Line HELB in the EPR. It also calculated the time requirement for the isolation of the Letdown Line break, in order to not exceed the dose limits (Reference 10.2.26).

OSC-9333 – Evaluation of West Penetration Room Structural Components

This calculation determined the capacities of the various structural components of the West Penetration Room and evaluated these capabilities against the internal pressurization loading resulting from a Main Steam Line Break in the adjoining East Penetration Room (Reference 10.2.28). The calculation also determined the maximum flood level the WPR floor slab and various masonry walls can withstand (Reference 10.2.28).

OSC-9344 – Evaluation of Jet Lengths from the Terminal End Main Feedwater HELBs in the East Penetration Rooms

This calculation evaluated the jet impingement from the terminal end breaks on the Main Feedwater Lines at Containment Penetrations #25 and #27 with the cable trays along the east wall of the East Penetration Rooms (Reference 10.2.34).

OSC-9352 – ROTSG Double Steam Line Break Evaluation

This calculation performed a system thermal-hydraulic analysis of a double Main Steam Line Break to evaluate the core response to the event (Reference 10.2.31).

OSC-9355 – Double Steam Line Break Analysis

This calculation performed a generic core analysis for a double Main Steam Line Break accident to determine whether re-criticality occurs (Reference 10.2.35). This calculation is linked to Calculation OSC-9352 (Reference 10.2.31).

OSC-9603 – Evaluation of Postulated Plant Heating System High Energy Line Breaks (HELBs) in Rooms 520 (Ventilation Equipment Room) and 408B (Storage Room)

This calculation provides an evaluation and documentation of the postulated PH System HELBs in Rooms 520 and 408B and their affects on the systems and structures used in the ONS Shutdown Sequence. This calculation also provides an evaluation and documentation for Rooms 505 & 565 for the PH System HELBs in those rooms (Reference 10.2.50).

OSC-9575 – High Energy Line break Inside the Turbine Building with SSF Restoration

This calculation provides a thermal-hydraulic analysis of a double steam line break (DSLB) inside the Turbine Building at the ONS. The accident assumes a double –ended rupture of both Main Steam Lines inside the turbine building, and the installation of the Main Steam Isolation Valves is considered in this calculation (Reference 10.2.63).

OSC-9696 – ONS HELB analysis – DSLB with PSW Recovery

This calculation demonstrates the ability of the Protected Service Water System to achieve and maintain a Safe Shutdown condition following a DSLB inside the Turbine Building (Reference 10.2.64).

1.4 QA Condition

This report establishes the High Energy Line Break configuration for the ONS, once all of the identified modifications, delineated in Section 9.0 of this report, have been installed. It will be used as the HELB licensing basis for the ONS, and it will supersede the HELB configuration provided in the 1973 ONS HELB Report, OS-73.2 (References 10.3.1 to 10.3.3). This report may also be used to provide input for future physical and procedural configuration changes to the ONS. As such, this report is QA Condition 1.

1.5 Definitions

The following definitions apply to the analyses and evaluation in this document:

Branch Line – A Branch connection is a piping line, where one of the terminal ends is at a piping intersection with a pipe of equal or larger size. A branch connection to a main piping line is a terminal end of the branch line, except where the branch line is classified a part of the main piping line in the stress analysis and is shown to have a significant effect on the main line behavior (Reference 10.1.4)

Branch Run – A Piping Run, where one of the extremities originates at a piping intersection and not at a component. (See Piping Run) (Reference 10.1.1)

Break – A complete circumferential pipe severance; or a longitudinal pipe split opening of an area equal to the pipe (cross-sectional) flow area, but without pipe severance (Reference 10.1.1 & 10.1.3)

Circumferential Breaks – HELBs that are perpendicular to the pipe axis and the break area is equivalent to the internal cross-sectional area of the pipe immediately upstream of the break location. The dynamic forces resulting from such breaks are assumed to separate the piping axially (initially) and cause the pipe ends to deflect in response to the discharging fluid. (References 10.1.1 & 10.3.17)

Cold Shutdown (Condition) – The state of an ONS Unit, when it is in a Mode 5 condition

Collateral Damage – Damage to plant equipment, which results in an adverse condition, caused by the structural failures that are a result of postulated HELBs.

Compartmental Pressurization – The change in the internal pressure of a station room or enclosure, caused by a postulated HELB within or adjacent to the room or enclosure

Containment (Reactor Building) – The enclosure that surrounds the Reactor Coolant System and acts as a leak tight barrier against the uncontrolled release of radioactivity from the RCS to the environment and serves as biological shield for the radioactivity contained therein.

Control Complex – The portion of the Auxiliary Building consisting of the Control Room (Room 510 – Units 1 & 2, Room 552 – Unit 3), Cable Spreading Room (Room 403- Unit 1, Room 404 – Unit 2, & Room 450 - Unit 3), and the Electrical Equipment Room (Room 310 – Unit 1, Room 311 – Unit 2, & Room 354 – Unit 3).

Critical Crack (Through-Wall Crack) – A through wall crack in a HE pipe with a crack area equivalent to ½ the pipe (inner) diameter by ½ the pipe wall thickness. The Critical Crack geometry is to be taken as a circular orifice through pipe wall, for flow purposes (References 10.1.2 & 10.3.17)

Direct HELB Interaction – An adverse condition created by an HELB, where the impact on plant systems, components, or structures caused by pipe whip or jet impingement and results in the loss or damage to that equipment

Environmental Qualification – A program of verifying that station equipment and components will function under the adverse environmental conditions (e.g. temperature, pressure, humidity, and radiation exposure) generated by postulated HELBs (& LOCAs)

Excluded Break - Those postulated breaks that are excluded from consideration of impacts to shutdown equipment. Breaks are excluded if any of the following were satisfied:

- Piping that does not exceed 200°F and 275 psig
- Portions of high energy systems that are isolated during normal operating conditions
- Piping operating at or below atmospheric pressure

High Energy Line – Piping line in the ONS, where the fluid inside of the pipe during Initial Operating Conditions has either or both of the following conditions:

- A normal operating temperature greater than 200°F
- A normal operating pressure greater than 275 psig

(References 10.1.1, 10.1.3, 10.2.1, 10.3.1, 10.3.16, & 10.3.17)

High Energy Line Break (HELB) – The instantaneous rupture of an HE line during Normal Plant Conditions

High Energy System – Any mechanical system outside of the containment in the ONS containing High Energy Lines (Reference 10.1.1)

Indirect HELB Interaction – An adverse condition created by an HELB that is not a result of a pipe whip or jet impingement on systems and components. Indirect HELB Interactions would be interactions caused by flooding, environmental effects (temperature, pressure, & humidity), and collateral damage from HELB generated structural interactions.

Initial Operating Conditions (or "Normal Operating Conditions") – These conditions are the physical parameters that would exist within an ONS Unit with the Unit operating at 100% rated thermal power level (full power). All plant systems are assumed to be aligned in their normal operating configuration for this power level. The Initial Operating Conditions are the conditions, upon which the HE Lines & their boundaries are identified. The Initial Operating Conditions also aid in the identification of the HELB locations and define the operating parameters that exist at the beginning of an HELB event sequence. (Note: For the purpose of conducting transient analysis and determining the most conservative adverse thermodynamic conditions, a power level of 102% of rated unit thermal power is identified as the Initial Operating Condition.)

Intermediate Break Location – A postulated HELB location that is not at the connecting weld to a vessel, pump, or at a rigidly restrained pipe section (A postulated HELB that is not at a Terminal End – See definition of "Terminal End")

Jet Impingement – The hydraulic force generated by the high energy fluid exiting the pipe break and impacting on other equipment or structures

Longitudinal Breaks - HELBs that are parallel to the pipe axis and orientated at any point around the pipe circumference. The break area is equal to the effective cross-sectional flow area upstream of the break location, and a longitudinal break does not result in pipe severance. Dynamic forces resulting from such breaks are assumed to cause lateral pipe movements in the directions normal to the pipe axis (References 10.1.1 & 10.1.4)

Loss of Offsite Power (LOOP) – the loss of the capability of the grid to provide auxiliary power to the three (3) ONS Units. The only auxiliary power available for the ONS Units is from the Keowee Hydro-electric Units, supplied through the 230 kV Switchyard or through transformer CT4

Mode 1 (Power Operation) – Operation of an ONS Unit with the following conditions: $k_{eff} \geq 0.99$ and the % Rated Thermal Power level > 5 (Reference 10.3.7)

Mode 2 (Startup) – Operation of an ONS Unit with the following conditions: $k_{eff} \geq 0.99$ and the % Rated Thermal Power level ≤ 5 (Reference 10.3.7)

Mode 3 (Hot Standby) – Operation of an ONS Unit with the following conditions: $k_{eff} < 0.99$ and the average Reactor Coolant Temperature is ≥ 250 °F (Reference 10.3.7)

Mode 4 (Hot Shutdown) – Operation of an ONS Unit with the following conditions: $k_{eff} < 0.99$ and the average Reactor Coolant Temperature (T) is 250 °F > T > 200°F (Reference 10.3.7)

Mode 5 (Cold Shutdown) – Operation of an ONS Unit with the following conditions: $k_{eff} < 0.99$ and the average Reactor Coolant Temperature is ≤ 200 °F. To be in Mode 5 all Reactor Vessel Head closure bolts must be fully tensioned (Reference 10.3.7)

Non-excluded Break - Those postulated breaks, which cannot be excluded from consideration of impacts to Shutdown Equipment

Normal Plant Conditions – An ONS Unit operating in Mode 1, 2, 3, or 4. This definition is used to exclude certain piping sections from the requirement of postulating HELBs on these sections (Reference 10.1.1 & 10.1.3).

Offsite Power – Electrical power used by the ONS for station auxiliary needs that is not generated directly by the ONS Units or the Keowee Hydro-electric Units

Pipe Whip – The movement of a ruptured pipe in response to the high energy fluid exiting the pipe break

Piping Run – A section of pipe that interconnects components such as pressure vessels, and pumps that may act to restrain pipe movements beyond that required for design thermal displacement (Reference 10.1.1)

Plant Cooldown – The transition of an ONS Unit from a Safe Shutdown condition to the Mode 4 Condition, where the RCS temperature is approximately 250°F and further cooling of the RCS via the Steam Generators is not practical

Plant Cooldown to the Cold Shutdown Condition – The transition of an ONS Unit from the Mode 4 Condition, where the RCS temperature is approximately 250°F to the Cold Shutdown Condition (Mode 5)

Return – to – Criticality – the reactor core returning to a value of $k_{eff} \geq 1.00$, following a unit shutdown (i.e. insertion of control rods into the core), as a result of the cooling of the RCS (water) inventory

Running Break – The general designation for all of the individual break locations on a non-seismically analyzed Piping Run

Safe Shutdown – The transition of an ONS Unit from a Mode 1 or Mode 2 condition to a Hot Standby (Mode 3) state with stable RCS conditions and the maintaining of the state without adversely impacting the health and safety of the public

Seismically Analyzed Piping Lines – Piping lines, where stress analysis information is available and where the analysis includes internal pressure, dead weight (gravity), thermal, and Operational Basis Earthquake (OBE) loadings

Shutdown Equipment – The systems and components used during the Shutdown Sequence to achieve the shutdown objectives (See Sections 3.5 & 3.6 of this report). The terms "Shutdown System" and "Shutdown Component" can also be used, when "Shutdown Equipment" is too general.

Shutdown Sequence – The description of the sequence of events of an ONS Unit from the Mode 1 state to the achievement of Mode 5 (Cold Shutdown Condition)

Single Active Failure (SAF) – The failure on demand of an "Active Component" to perform its intended safety function. An "Active Component" is a component that is externally powered and a mechanical movement within the component is necessary to perform the safety function. Failure of additional components and/or systems that result from this failure is considered part of the SAF. Self-actuated valves such as simple (not power operated) check valves, vacuum breaker valves, and safety/relief valves are not considered to be candidates for active failures. (Reference 10.3.6)

Sub-Break – An individual HELB of one break type at one location on a Running Break. The terms "Sub-Break," "Discrete Break" and "Individual Break" are used interchangeably

Subcritical – the condition of the reactor core, wherein $k_{eff} < 1.00$

Terminal End – The interconnection point of a piping run with a plant component such as a pressure vessel, pump (nozzle), building penetration, in-line anchors, and decoupled branch to run connections, that may act as points of maximum constraint to pipe thermal expansion movements (References 10.1.3 & 10.3.17)

Type "A" Variables – Those variables (plant parameters), which are monitored to provide the primary information required to permit the Control Room Operator to take specific actions, for which no automatic control is provided and that are required for safety systems to accomplish their safety functions (Reference 10.2.4). Type "A" variables[1] include:

- RCS Pressure/Temperature
- Core Exit (Thermocouples) Temperature
- Pressurizer Level
- Degrees Subcooling
- Steam Generator Level
- Steam Generator Pressure
- Borated Water Storage Tank Level
- High Pressure Injection Flow
- Low Pressure Injection Flow
- Reactor Building Spray Flow
- Reactor Building Hydrogen Concentration
- Upper Surge Tank Level
- Low Pressure Service Water Flow to Low Pressure Injection Coolers

Type "D" Variables – Those variables (plant parameters), that provide information to allow the operators to determine the operating status of a safety system (Section 7.5.1.3 –Reference 10.3.4).

[1] It should be noted that all Type "A" Variables are listed for consistency of definition. However, the Reactor Building Spray Flow and the Reactor Building Hydrogen Concentration are not needed for postulated HELB events outside of the Containment.

The two (2) Type "D" variables identified in this report are EFW Flow and Decay Heat Cooler Discharge Temperature.

Unit Blackout – The simultaneous loss of the Main Feeder Buses 1 and 2 (4160 VAC) in any unit. The terms "Unit Blackout" and "Loss of the 4160 VAC Power Distribution System" will be used interchangeably

1.6 Acronyms Used in this Document

The following acronyms are used within this document:

AB – Auxiliary Building
AC – Alternating Current
ACI – American Concrete Institute
ADVs – Atmospheric Dump Valves
AEC – Atomic Energy Commission
AFIS – Automatic Feedwater Isolation System
AHU – Air Handling Unit
AIA – Auxiliary Instrument Air (System)
AISC – American Institute of Steel Construction
ANSI – American Nation Standards Institute
AS – Auxiliary Steam (System)
ASB – Auxiliary Systems Branch
ASME – American Society of Mechanical Engineers
ASW – Auxiliary Service Water
BTP – Branch Technical Position
BWST – Borated Water Storage Tank
C – Condensate (System)
CC – Component Cooling (System)
CCW – Condenser Circulating Water (System)
CET – Core Exit Thermocouple
CF – Core Flood (System)
CFT – Core Flood Tank
CFR – Code of Federal Regulations
Ch – Channel
CLB – Current Licensing Basis
CPS – Counts per Second
CR – Critical Crack
CRD – Control Rod Drive (System)
CSD – Cold Shutdown Condition
CST – Condensate Storage Tank
DC – Direct Current
DNBR – Departure from Nucleate Boiling Ratio
DSLB – Double Steam Line Break
DPC – Duke Power Company
DSW – Diesel Service Water

EFW – Emergency Feedwater (System)
EFWP – Emergency Feedwater Pump
EHC – Electro-Hydraulic Control
EOP – Emergency Operating Procedure
EPR – East Penetration Room
EQ – Environmental Qualification
EQCM – Equipment Qualification Criteria Manual
ES – Extraction Steam (System)
ESAE – Emergency Steam Air Ejector
ESG – Engineered Safeguards (System)
ESV – Essential Siphon Vacuum (System)
FAC – Flow Accelerated Corrosion
FDW or MFDW – (Main) Feedwater (System)
FOD – Flood Outlet Device
FP – Full Power
FSRH – First Stage Reheater
FWCV(s) – (Main) Feedwater Control Valve(s)
FWLB – (Main) Feedwater Line Breaks
FWPT – Feedwater Pump Turbine
GPM (or gpm) – Gallons per Minute
HD – Heater Drain (System)
HDLB – Heater Drain Line Breaks
HE – High Energy
HEL – High Energy Line
HELB – High Energy Line Break
HP – High Pressure
HPI – High Pressure Injection (System)
HPSW – High Pressure Service Water (System)
HV – Heater Vent (System)
HVAC – Heating, Ventilating, and Air Conditioning
IA – Instrument Air (System)
IB – Intermediate Break
I&C – Instrumentation and Control
ICCM – Inadequate Core Cooling Monitor
ICS – Integrated Control System
ID – (Pipe) Inner Diameter
IST – In-Service Testing
KHU – Keowee Hydro-electric Unit
KV (or kV) - Kilovolts
KW (or kW) – Kilowatts
LCO – Limiting Condition of Operation
LC – Load Center
LDST – Letdown Storage Tank
LOCA – Loss of Coolant Accident
LOOP – Loss of Offsite Power
LP – Low Pressure

LPI – Low Pressure Injection (System)
LPSW – Low Pressure Service Water (System)
MCC – Motor Control Center
MCR – Main Control Room
MDEFW(P) – Motor Driven Emergency Feedwater (Pump)
MEB – Mechanical Engineering Branch
MFB – Main Feeder Bus
MFLB – Main Feedwater Line Break
MOV – Motor Operated Valve
MS – Main Steam (System)
MSIV – Main Steam Isolation Valve
MSLB – Main Steam Line Break
MSPB – Main Steam Pressure Boundary
MSR – Moisture Separator Reheater
MSRD – Moisture Separator Reheater Drain (System)
MSRH – Moisture Separator Reheater
MSRV – Main Steam Relief Valves
MT – Magnetic-Particle Test
MWth – Megawatts (thermal)
NPSH – Net Positive Suction Head
NRC – Nuclear Regulatory Commission
OBE – Operational Basis Earthquake
ONS – Oconee Nuclear Station
PCB – Power Circuit Breaker
pf – Power Factor
PH – Plant Heating (System)
PORV – Power Operated Relief Valve
PR – Pipe Rupture
PRVS – Penetration Room Ventilation System
PS – Pressure Switch
PSF – Pounds per Square Foot
PSIG – Pounds per Square Inch Gauge
PSW – Protected Service Water (System)
PT – (Liquid) Penetrant Test
QA – Quality Assurance
RB – Running Break
RBES – Reactor Building Emergency Sump
RBU – Reactor Building
RC – Reactor Coolant
RCMU – Reactor Coolant Make Up (System)
RCP – Reactor Coolant Pump
RCS – Reactor Coolant System
RCW – Recirculated Cooling Water
ROTSG – Replacement Once Through Steam Generator
RPS – Reactor Protection System
RTD – Resistance Temperature Detector

RV – Reactor Vessel
SAF – Single Active Failure
SBB – Standby Bus
SBO – Station Blackout
SCD – Statistical Core Design
SCM – Sub-Cooling Margin
SD – Steam Drain (System)
SER – Safety Evaluation Report
SG – Steam Generator
SRP – Standard Review Plan
SSC – Structures, Systems, and Components
SSD – Safe Shutdown
SSF – Standby Shutdown Facility
SSFCR – SSF Control Room
SSH – Steam Seal Header (System)
SSRH – Second Stage Reheater
SSTL – Safe Shutdown Target List
SSW – Siphon Seal Water (System)
SWGR – Switchgear
TB – Turbine Building
TBV – Turbine Bypass Valve
TDEFW(P) – Turbine Driven Emergency Feed Water (Pump)
TE – Terminal End
TEDE – Total Effective Dose Equivalent
TMI – Three Mile Island (Nuclear Station)
TSOR – Thermal Shock Operating Range
UFSAR – Updated Final Safety Analysis Report
UPS – Uninterruptible Power Supply
USAS – United States of America Standard
UST – Upper Surge Tank
UT – Ultrasonic Test
VAC – Volts Alternating Current
VDC – Volts Direct Current
WPR – West Penetration Room
ZOI – Zone of Influence

2.0 EVALUATION CRITERIA

2.1 Regulatory Requirements

The regulatory requirements for the ONS are defined in the Implementation Section of Branch Technical Position ASB 3-1 of SRP 3.6.1 (Reference 10.1.3). Specific guidance is provided in Section B.4.d of the BTP, in which it is stated that for plants with Operating Licenses issued before July 1, 1975, the requirements of the Giambusso/Schwencer Letters (Reference 10.1.1 & 10.1.2) applied. The ONS Units were licensed to operate before the July 1, 1975 date, and the Unit 2 & 3 SER was issued on June 6, 1973. Hence the regulatory basis for the ONS is contained within the Giambusso/Schwencer Letters, which is Appendix B of SRP 3.6.1, BTP ASB 3-1 (Reference 10.1.3).

In addition to the Giambusso/Schwencer Letters, SRP 3.6.1 (Reference 10.1.3) and SRP 3.6.2 (Reference 10.1.4) will be used to provide guidance by supplementing and clarifying the requirements in the Giambusso/ Schwencer Letters and eliminating ambiguities amongst the various regulatory and licensing documents. This includes adopting portions of Generic Letter 87-11 (Reference 10.1.5). In that generic letter those portions that eliminated the arbitrary intermediate HELBs and Critical Cracks will be used for establishing pipe break locations on the seismically analyzed HE piping lines in the ONS. Specific mitigation strategies, regulatory commitments, and responses, were provided to the NRC in the November 30, 2006 letter (Reference 10.1.6) and the January 25, 2008 letter (Reference 10.1.7) from Duke Energy, and the information in these letters form the basis for this document.

2.2 Identification of High Energy Lines, Break Locations, and Break Types

2.2.1 Identification of High Energy Lines

The following criteria are used to identify the HE piping and the boundaries of the HE portions of the systems (References 10.1.1, 10.1.3, 10.2.1, 10.3.1, 10.3.17 & 10.3.18):

- The High Energy (Piping) lines are those lines that during Initial Operating Conditions the fluid inside of the pipe has either or both of the following conditions:

  1. A normal operating temperature greater than 200°F

  2. A normal operating pressure greater than 275 psig

- The high energy section of any piping run shall extend from component to component. The high energy portion shall not terminate unless there is a termination at a vessel, a pump, or a closed valve. The high energy portion of a piping run can also be terminated, when the piping line size is reduced to 1" nominal size or smaller.

- Piping downstream of a normally closed valve, that is the HE boundary for a HE piping run, is not postulated to be High Energy due to potential leakage across the closed valve.

- High Energy Line Boundaries shall be based upon the normal operating configuration of the system with the unit operating at 100% rated thermal power level (Full Power) (Reference 10.3.17)

- Gas Systems (e.g. Nitrogen) and oil systems (e.g. EHC) are not identified as high energy systems because those systems possess limited energy (References 10.2.1 & 10.3.17).

2.2.2 Identification of High Energy Line Break Locations

The following criteria are used to identify the HE piping break locations:

- HELBs and Critical Cracks are postulated on HE Lines that exceed 1" nominal pipe size (References 10.1.1 & 10.3.1)

- HELBs and Critical Cracks are not postulated on HE Lines that operate at HE conditions less than 2% of the total system operating time (References 10.1.4 & 10.3.17)

- HELBs and Critical Cracks are not postulated on HE Lines that operate at HE conditions less than 1% of the total plant (unit) operating time (Normal Plant Conditions) (References 10.3.17 & 10.3.18)

- For piping that is seismically analyzed HELBs are postulated at the Terminal Ends of HE piping runs (References 10.1.1 and 10.1.4)

- For piping that is seismically analyzed, HELBs are postulated at intermediate break locations on equivalent Class 2 or Class 3 piping axial locations, where the calculated longitudinal stress for the applicable load cases (internal pressure, dead weight (gravity), thermal, and seismic (OBE) conditions) exceeds $0.8(S_A + S_h)$ (Reference 10.1.1)

- Intermediate Breaks are not postulated at locations, where the expansion stress, by itself, exceeds $0.8\ S_A$. (The level of stress at the postulated intermediate point must exceed the stress limit defined in the previous item, in order to require a postulated intermediate HELB be identified at that point.) (Reference 10.1.5)

- For branch connections to piping runs, a branch, appropriately modeled in a rigorous stress analysis with run flexibility and applied branch line movements included and where the branch connection stress is accurately known, will use the stress criteria for seismically analyzed piping lines, for postulating HELB locations.

- Breaks & Critical Cracks at closed valves are postulated as follows. The postulation of terminal end breaks at the first normally closed valve(s) separating portions of a system maintained pressurized during normal operations and portions of a system not maintained pressurized depends on whether the system has a seismic analysis that is continuous across the valve. For systems or portions of systems that are not seismically analyzed, breaks are postulated to occur at all piping girth welds in the system including those that attach to normally closed valves. For systems or portions of systems that are seismically analyzed, and the analysis is continuous across the normally closed valve, such that stresses can be accurately determined, break and crack locations are determined based on comparison to the break and crack stress thresholds.

- For piping that is not rigorously analyzed or does not include seismic loadings, HELBs shall be postulated at the terminal ends, and intermediate break locations as provided in BTP MEB 3-1, Section B.1.c.(2)(b)(i). (References 10.1.5, 10.1.6, & 10.1.7).

- For unanalyzed branch connections or where the stress at the branch connection is not accurately known, the break locations shall be postulated as defined in the previous item.

- For piping that is seismically analyzed (i.e., stress analysis information is available and the analysis includes seismic loading), critical cracks will be postulated in equivalent Class 2 and Class 3 piping at axial locations where the calculated stress for the applicable load cases exceed $0.4(S_A+S_h)$. Applicable load cases include internal pressure, dead weight (gravity), thermal, and seismic (OBE). Critical Cracks are not postulated at locations of Terminal End or Intermediate Breaks (References 10.1.2 & 10.1.5)

- For piping that is not rigorously analyzed or does not include seismic loadings, critical cracks shall not be postulated since the effects of postulated HELBs on these piping runs will bound the effects from critical cracks (References 10.2.2 & 10.3.17).

- Actual stresses used for comparison to the break and crack thresholds noted above will be calculated in accordance with the ONS piping code of record, USAS B31.1.0 (1967 Edition). Allowable stress values S_A and S_h will be determined in accordance with USAS B31.1.0 or the USAS B31.7 (February 1968 draft edition with errata) code as appropriate. (Table 3-1 of Reference 10.3.8)

- Moderate energy line breaks are not postulated. The HELB requirements for the ONS, as defined in Reference 10.1.3, only require compliance to the Giambusso/Schwencer letters (References 10.1.1 & 10.1.2). The requirements contained therein do not include postulation of moderate energy line breaks.

- High Energy Piping lines with an internal pressure at atmospheric or below (≤ 0 psig) are excluded from damage assessments due to insufficient energy to create pipe whip or jet impingement forces.

2.2.3 High Energy Break Type Criteria

The following criteria are used to identify the HE break types, required to be postulated at the identified break locations in the ONS. There are three (3) types of HELBs at the ONS.
These include circumferential breaks, longitudinal breaks, and critical cracks. The definition and description of each of these break types are provided in Section 1.5. The criteria for each break type are as follows (References 10.1.1, 10.1.3, & 10.3.17):

- Circumferential Breaks are to be postulated in HE lines that exceed 1 inch in nominal pipe size.

- Longitudinal Breaks are to be postulated in HE piping that has a nominal pipe size of four (4) inches or greater.

- Critical Cracks are to be postulated on seismically analyzed HE piping that exceeds 1 inch in nominal pipe size (See Section 2.2.2 for exceptions).

- HELBs of any type are <u>not</u> postulated on HE piping that has a nominal pipe of 1 inch or less.

- Only circumferential breaks are to be postulated at terminal ends of HE piping runs. (Longitudinal breaks are <u>not</u> postulated at terminal ends.)

- Longitudinal breaks are to be postulated only at intermediate break locations on HE piping runs.

- For piping that has a nominal pipe size of four (4) inches or greater both circumferential and longitudinal breaks are to be postulated at the intermediate break locations <u>but not concurrently</u>.

- Longitudinal breaks are to be postulated parallel to the pipe axis and orientated at any point on the pipe circumference.

- The break area of a longitudinal break is equal to the effective cross-sectional flow area of the pipe immediately upstream of the break location.

- Longitudinal breaks are not required to be postulated at branch connections.

2.3 <u>Shutdown Sequence Evaluation Criteria</u>

In order to establish the list of targets for the postulated HELBs, it is necessary to know which systems & components will be required to mitigate the consequences of the postulated HELBs and safely bring the Unit to the Cold Shutdown Condition. This list of systems & components can be, in part, determined by establishing the Shutdown Sequence for the station. The following criteria are used to identify the systems and components necessary for HELB mitigation and/or Unit shutdown to the Cold Shutdown Condition:

- Equipment used to mitigate postulated HELBs shall include those systems and components that are used for detection and isolation of specified HELBs. Equipment that is used for the detection and isolation for an identified HELB is the only detection and isolation equipment required to be targets of that specific HELB.

- Equipment used to meet any of the following Shutdown Objectives shall be considered a target of postulated HELBs:

- Reactivity Control
- RCS Inventory Control
- RCS Pressure Control
- RCS Heat Removal
- Reactor Building (Boundary) Integrity
- Control Room Habitability (long term)
- Plant Cooldown (see definition in Section 1.5)

• Both primary systems and the back-up systems, used to achieve the Shutdown Objectives described above, shall be included as Shutdown Equipment and targets of the postulated HELBs (Reference 10.2.4).

• Piping, orifices, relief valves, and check valves, are considered passive type components in that they do not require an external power source or manual action to perform their intended function, and these components perform their intended function regardless of the environmental conditions. These components need not be identified as required components in the Shutdown Sequence, because they are not subject to Single Active Failures (These components are, however, HELB targets.) (Reference 10.2.4).

• The Instrument Air (IA) and Auxiliary Instrument Air (AIA) Systems are not to be considered for use in establishing the Shutdown Sequence with two (2) exceptions. The RCP Seal Injection Line HELBs in the EPR & WPR require IA to isolate these postulated HELBs (References 10.2.20 & 10.2.24). Moreover, the IA & AIA Systems are credited for continued operation of the CC System (valve xCC-8), following HPI Seal Injection Line HELBs.

• If normal RCP Seal Injection from the HPI System is lost, the Component Cooling System is credited for RCP seal cooling.

• The Reactor Building Penetration Room Ventilation System is excluded as a Shutdown System (Reference 10.2.8).

• The Type "A" Variables (system physical parameters), required for HELB mitigation and for achieving and maintaining a Safe Shutdown condition (See definition of Type "A" Variables in Section 1.5), shall be identified in the Shutdown Sequence.

• The PSW and the SSF are to be included in the Shutdown Sequence.

• The Shutdown Sequence does not credit steaming of the Steam Generators to the Condenser. The credited method of decay heat removal from the Steam Generators is through the Atmospheric Dump Valves or the MSRVs on the Main Steam Lines.

2.4 Interaction Evaluation Criteria

The following criteria are used to determine the interactions that occur as a result of postulated HELBs with Shutdown equipment and the criteria for determining the pathway to Cold Shutdown for a given postulated HELB:

- The targets of the postulated HELBs are those systems & components required to mitigate the consequences of postulated HELBs and/or are used during the Shutdown Sequence to safely bring the Unit to the Cold Shutdown Condition.

- Any unidentified electrical equipment (e.g. cable trays, conduits, terminal boxes, etc.) shall be identified as HELB targets. The systems & components affected by the HELB interactions with the electrical equipment shall be identified and documented.

- HELBs shall be postulated to occur with the Unit operating at the Initial Operating Conditions.

- Safe Shutdown, Cold Shutdown, and HELB mitigation systems and components directly impacted by a specific postulated HELB are considered to be unavailable to support the Shutdown Objectives for that specific HELB, unless documented otherwise.

- Movement of a ruptured HE pipe (i.e. pipe whip) shall be determined based upon the criteria established in the ONS "HELB Outside Containment Walkdown Criteria & Requirements," Section 5.6 (Reference 10.3.17).

- The energy level in whipping pipes may be considered insufficient to rupture an impacted pipe of equal or greater nominal pipe size and equal or heavier wall thickness (Reference 10.1.1).

- No secondary pipe breaks are postulated due to jet impingement from the source pipe (pipe with postulated HELB).

- The Jet Impingement Forces, Jet Impingement Cone Geometry, and the Jet Impingement Effective Length are determined in accordance with NUREG/CR-2913, "Two Phase Jet Loads," subject to the pressure and temperature limitations given in the NUREG (i. e. stagnation pressures from 870 psia to 2465 psia, 0 to 126°F subcooling, and 0 to 75% steam quality). For jets consisting of steam or subcooled liquid water falling outside of the NUREG limitations, the effective length of the jet will be 10 pipe diameters (ID). Similarly, jet lengths from Critical Cracks will be limited to 5 pipe diameters (ID) (Reference 10.3.10 & 10.3.17).

- Thrust Loads for evaluating potential interactions between postulated HELBs and the Turbine Building structural components will be determined in accordance with ANSI 58.2 (Reference 10.3.11).

- A Single Active Failure (SAF) shall be postulated in systems used to mitigate the consequences of the postulated HELBs & Critical Cracks or those systems used to achieve a Shutdown Objective of the unit. The single active component failure is assumed to occur in addition to the postulated pipe break and any additional failures of structures, systems and components resulting from the direct consequences of the SAF (Reference 10.1.1).

- Systems and Components, whose only function is to support the cooldown of the Unit from an RCS temperature of approximately 250°F to the Cold Shutdown Condition, are not protected from postulated HELBs.

- No SAFs will be postulated during the "Plant Cooldown" phase and the "Plant Cooldown to the Cold Shutdown Condition" phase (Reference 10.1.6).

- All available systems, including those actuated by operator actions, may be employed to mitigate the consequences of a postulated HELB or Critical Crack. In judging the availability of these systems and components account should be taken of the HELB and its direct consequences, any SAFs, and the availability of power (Reference 10.1.3).

- In judging the feasibility of carrying out an operator action consideration needs to be given to the time implementation requirements, adequacy of access, and ingress & egress routes to the equipment being utilized for the proposed actions (Reference 10.1.3).

- A "Loss of Offsite Power" (LOOP) will be postulated for Main Steam Line Breaks (MSLB) and Main Feedwater Line Breaks (MFLB). A LOOP is only postulated for MSLBs and MFLBs in a manner consistent with the post-TMI EFW Licensing Basis. Other HELBs do not have a postulated LOOP unless the initiating break directly causes a LOOP. (Reference 10.3.9)

- For each postulated HELB or Critical Crack a pathway for achieving and maintaining a Safe Shutdown condition and subsequent cooldown to the Cold Shutdown Condition shall be demonstrated, utilizing that equipment that is available to support the safe unit shutdown and consistent with the requirements for SAFs, availability of power, and ability to perform operator manual actions.

- In determining the systems and components available to mitigate the consequences of postulated HELBs, all Shutdown Equipment is assumed to be operable and available at the start of the postulated HELB sequence. It is not necessary to postulate that any systems or components are out of service for maintenance.

- The following systems are excluded as being Shutdown Equipment targets because they are not required or are not available to be part of the Shutdown Sequence for the unit (Reference 10.2.4)

    - Main Feedwater is not credited for feeding the Steam Generators for HELBs in the Turbine Building

- Reactor Trip Breakers and Control Rod Drive (CRD) System[2]
- Integrated Control System (ICS)
- Incore Monitoring System
- ATWS Mitigation System
- Reactor Building Penetration Room Ventilation System (PRVS)
- Reactor Building Cooling System
- Reactor Building Purge Valves (PR-1 through PR-6)
- Reactor Building H2 Purge Isolation Valves (PR-59 & PR-60)
- Steam Generator Hot Blow-Down System
- Instruments that are Type B, Type C, Type D, and Type E variables[3]
- Hotwell Emergency Makeup #2 Control Valve and Solenoid Valve (C-176 and CSV-1760)

- HELB interactions with cables result in the affected component(s) failing in the most undesired state. However, the following exceptions apply. If an electric Load Center (LC) or Motor Control Center (MCC) is affected by interactions, the LC or MCC is considered to be de-energized. Components receiving power from this LC or MCC are considered de-energized and unable to function unless alternate power supplies are available. Valves directly powered from an affected MCC fail "as is" regardless of other interactions.

- HPI makeup capability is required for Plant Cooldown (See definition in Section 1.5).

- Loss of Control Area cooling does not result in an immediate loss of Control Room habitability. However, any postulated HELB that results in the loss of the control area (Control Complex) cooling and where alternate cooling would need to be established should be identified and documented.

- For postulated HELBs in the Turbine Building, where the direct pipe whip and/or jet impingement interactions result in the loss of the 4160 VAC Power Distribution System and/or result in Turbine Building flooding, the PSW and the SSF Systems shall be identified as the primary and backup systems (respectively) to be used to achieve and maintain a Safe Shutdown condition. For all other postulated HELBs in the Turbine Building, it is expected that the indirect effects of these HELBs will not render the Shutdown Equipment in the Turbine Building unavailable in the short term. However, the determination of the availability of these systems and components is not necessary, because the PSW and the SSF Systems are available for achieving and maintaining a Safe Shutdown state.

[2] The Reactor Trip Breakers and the Control Rod Drive System can be excluded from the list of Shutdown Equipment components and potential HELB targets because the unit trip function can be considered to be completed prior to any potential degradation of the system due to any gradual adverse environmental effects caused by postulated HELBs.
[3] In general, the Type B, Type C, Type D, & Type E Variables are excluded as Shutdown Equipment targets. However, individual parameters of these types may be desired (and hence become targets and part of the Shutdown Sequence) for specific postulated HELBs.

3.0 DETERMINATION OF SAFE SHUTDOWN SYSTEMS

3.1 HELB Mitigation Strategy

The revised HELB Mitigation Strategy addresses the level of protection provided to systems, structures and components (SSC) necessary to reach safe shutdown (SSD) from the direct affects (pipe whip and jet impingement) and indirect affects (environmental & flooding) of a given HELB outside containment. The major points of the new strategy are as follows:

- SSCs located in the Turbine Building (TB) are protected from HELBs postulated to occur in the Auxiliary Building (AB) or outside of the TB.
- SSCs located in the AB are protected from HELBs postulated to occur in the TB.
- Single active failures will be imposed for those systems required for initial event mitigation.
- Single active failure will not be imposed for those systems required to initiate a cool-down of the plant.
- HELBs resulting in the loss of plant systems inside the Turbine Building needed for SSD will be mitigated by the Protected Service Water (PSW) System.
- Should the PSW System be unavailable, the Standby Shutdown Facility (SSF) will be credited as an alternate means of achieving and maintaining SSD following HELBs that disable plant systems inside the Turbine Building.
- The Main Steam Isolation Valves (MSIVs) are designed to automatically close on low MS pressure or be closed by the operators to isolate the MS lines inside the Turbine Building.
- No credit is taken for the MSIV following a rupture of a Main Steam line upstream of the MSIV. The Main Turbine Stop Valves will continue to be credited to separate the MS headers such that only one SG is affected.

The PSW electrical system provides power to portions of the existing High Pressure Injection (HPI) System. For purposes of this report, the PSW System, and those portions of the HPI System powered by the PSW switchgear will be referred to as the PSW System. The SSF System is capable of providing secondary side decay heat removal and Reactor Coolant Pump (RCP) seal injection subsequent to a HELB event to maintain the affected units in Safe Shutdown (SSD) conditions for up to 72 hours. This mission time is consistent with the SSF Current Licensing Basis (CLB). Following a reactor trip, MS pressure is controlled by automatic closure of the Main Turbine Stop Valves and either the MSRVs or the TBVs. Other branch lines on the MS system are either automatically isolated or isolated by the operator, as needed, to prevent overcooling of the RCS. The MSIVs provide an alternate means of MS isolation following HELBs inside the TB that may affect the MS pressure boundary. For more details on how these systems would mitigate Main Steam and Main Feedwater line breaks, refer to Section 7.0 of this report.

The PSW System reduces reliance on systems and components located in the TB and will be capable of mitigating HELBs in that building. The PSW System is redundant to and diverse from the SSF System. Its mission is to achieve and maintain SSD by maintaining shutdown margin, reactor coolant system inventory and reactor coolant temperature and pressure within acceptable limits.

3.2 Description of the PSW System

The PSW System is designed as a standby system for use under emergency conditions where plant systems in the TB are lost. The PSW System will include a dedicated power system. The PSW System provides additional "defense in-depth" protection by serving as a backup to existing safety systems and as such, the system is not required to comply with single failure criteria. The PSW System is provided as an alternate means to achieve and maintain a stable RCS pressure and temperature for one, two, or three units following postulated HELB event scenarios.

Additionally, the PSW System is also capable of cooling the RCS to 250°F and maintaining this condition until damage repairs can be implemented to proceed to cold shutdown. Failures in the PSW System will not cause failures or inadvertent operations in existing plant systems. The PSW System is fully operational from the Main Control Rooms and will be activated when existing redundant emergency systems are not available.

The mechanical portion of the PSW System is designed to provide decay heat removal by feeding Keowee Lake water to the secondary side of the steam generators. The system, consisting of one booster pump and one high head pump, shall be capable of providing 375 gpm per unit at 1082 psig within 15 minutes following the initiating event. In addition, the system is designed to supply Keowee Lake water at 10 gpm per unit to the HPI pump motor coolers.

The PSW System utilizes the inventory of lake water contained in the plant Unit 2 CCW embedded piping. The PSW pump is located in the Auxiliary Building at Elev. 771' and takes suction from the Unit 2 CCW embedded piping and discharges into the steam generators of each unit via separate lines into the emergency feedwater headers. The raw water is vaporized in the steam generator removing residual heat and then dumped to the atmosphere. The Unit 2 CCW embedded piping is interconnected with Units 1 & 3. For extended operation, a submersible pump, powered by PSW and accessories (electrical cables, flexible hoses and connectors) can be utilized via operator actions to pump water directly from Lake Keowee to the Unit 2 CCW embedded piping.

The piping system has pump minimum flow lines that discharge back into the Unit 2 CCW embedded piping. For flow testing to the steam generators, the system is connected to a condensate water source located in the Turbine Building that is normally isolated using valves in the Auxiliary Building.

The PSW pumps and motor operated valves required to bring the system into service are controlled from the Main Control Rooms. Check valves and manual hand wheel operated valves are used to prevent back-flow, accommodate testing, or are used for system isolation. Pumps and valves will be ASME Section III Class 3. Piping will be designed to the 1967 Edition of USAS B31.1 (Oconee Class F). Periodic testing of the PSW valves and pumps will be accommodated via the In Service Testing (IST) program.

The PSW electrical system is designed to provide power to PSW mechanical and electrical components as well as other system components needed to establish and maintain a Safe Shutdown condition. A separate PSW electrical equipment structure is provided for major PSW electrical equipment. Power is provided from the Keowee Hydroelectric Units via a protected underground path. Alternate power is provided by a transformer connected to a 100 kV overhead transmission line that receives power from the Central Tie Switchyard located approximately 8 miles from the plant. These external power sources provide power to transformers, switchgear, breakers, load centers, and battery chargers located in the PSW electrical equipment structure.

The power system provides backup power to the following:

- 125 VDC Vital I&C Normal Battery Chargers - two (2) per unit.
- One HPI pump per unit (2 HPI pumps available).
- HPI valves needed to align the HPI pumps to the Borated Water Storage Tanks.
- HPI valves and instruments that support RCP seal injection and RCS makeup.
- Pressurizer Heaters ($\geq$ 400 kW).
- RCS and Reactor Vessel Head high point vent valves.
- Submersible pump.
- Standby Shutdown Facility (SSF).

The PSW System has dedicated instrumentation and controls located in each Main Control Room as follows:

- Two (2) high flow controllers (one per SG).
- Two (2) low flow controllers (one per SG).
- One (1) flow indicator (per SG).
- Two (2) SG header isolation valves (one per SG header).
- Two (2) HPI System power transfer switches per unit.
- Power transfer switches to HPI valves needed to align the BWST to the HPI pumps.

The following critical reactor parameters needed to support PSW event scenarios, are monitored in the Main Control Rooms:

- Two (2) Hot Leg Temperature.
- Two (2) Cold Leg Temperature.
- Twelve (12) Core Exit Thermocouples.
- RCS Pressure (Trains A & B).
- RCP Seal Injection Flow.
- HPI Injection Flow (Train A).

- Pressurizer Level (Train A & B).

3.3 Description of the Standby Shutdown Facility

The Standby Shutdown Facility (SSF) is designed as a standby system for use under certain emergency conditions. The system provides additional "defense in-depth" protection for the health and safety of the public by serving as a backup to existing safety systems. The SSF is provided as an alternate means to achieve and maintain the unit in MODE 3 with average RCS temperature ≥ 525°F (unless the initiating event causes the unit to be driven to a lower temperature) following postulated fire, sabotage, Turbine Building flood, station blackout (SBO), tornado missile, high energy line break events, and is designed in accordance with criteria associated with these events. The SSF is described in UFSAR Section 10.4.7. Since the SSF is a backup to existing safety systems, the single failure criterion is not required. Failures in the SSF systems will not cause failures or inadvertent operations in other plant systems. The SSF requires manual activation and can be activated if emergency systems are not available.

The SSF is designed to maintain the reactor in a safe shutdown condition for a period of 72 hours following fire, Turbine Building flood, sabotage, SBO, tornado missile events, or high energy line breaks. This is accomplished by re-establishing and maintaining Reactor Coolant Pump Seal cooling; assuring natural circulation and core cooling by maintaining the primary coolant system filled to a sufficient level in the pressurizer while maintaining sufficient secondary side cooling water; and maintaining the reactor sub-critical by isolating all sources of Reactor Coolant System (RCS) addition except for the Reactor Coolant Makeup System which supplies makeup of a sufficient boron concentration.

The main components of the SSF are the SSF Auxiliary Service Water (ASW) System, SSF Portable Pumping System, SSF Reactor Coolant (RC) Makeup System, SSF Power System, and SSF Instrumentation.

The SSF ASW System is a high head, high volume system designed to provide sufficient steam generator (SG) inventory for adequate decay heat removal for three units during a loss of normal AC power in conjunction with the loss of the normal and emergency feedwater systems or PSW. One motor driven SSF ASW pump, located in the SSF, serves all three units. The SSF ASW pump, two HVAC service water pumps, and the Diesel Service Water (DSW) pump share a common suction supply of lake water from the embedded Unit 2 condenser circulating water (CCW) piping. The SSF DSW pump and an HVAC pump must be operable in order to satisfy the operability requirements for the Power System. (Only one HVAC service water pump is required to be operable to satisfy the LCO.)

The SSF ASW System is used to provide adequate cooling to maintain single phase RCS natural circulation flow in MODE 3 with an average RCS temperature ≥ 525°F (unless the initiating event causes the unit to be driven to a lower temperature). In order to maintain single phase RCS natural circulation flow, an adequate number of Bank 2, Group B and C pressurizer heaters must be operable. These heaters are needed to compensate for ambient heat loss from the pressurizer. As long as the temperature in the pressurizer is maintained, RCS pressure will also be maintained. This will preclude hot leg voiding and ensure adequate natural circulation cooling.

The SSF Portable Pumping System, which includes a submersible pump and a flow path capable of taking suction from the intake canal and discharging into the Unit 2 CCW line, is designed to provide a backup supply of water to the SSF in the event of loss of CCW and subsequent loss of CCW siphon flow. The SSF Portable Pumping System, powered from the SSF electrical system, is installed manually according to procedures.

The SSF RC Makeup System is designed to supply makeup to the RCS in the event that normal makeup systems are unavailable. An SSF RC Makeup Pump located in the Reactor Building of each unit supplies makeup to the RCS should the normal makeup system flow and seal cooling become unavailable. The system is designed to ensure that sufficient borated water is provided from the spent fuel pools to allow the SSF to maintain all three units in MODE 3 with average RCS temperature ≥ 525°F (unless the initiating event causes the unit to be driven to a lower temperature) for 72 hours. An SSF RC Makeup Pump is capable of delivering borated water from the Spent Fuel Pool to the RC pump seal injection lines. A portion of this seal injection flow is used to make up for reactor coolant pump seal leakage while the remainder flows into the RCS to make up for other RCS leakage (non LOCA).

The SSF Power System provides electrical isolation of SSF equipment from non-SSF equipment. The SSF Power System includes 4160 VAC, 600 VAC, 208 VAC, 120 VAC and 125 VDC power. It consists of switchgear, a load center, motor control centers, panel-boards, remote starters, batteries, battery chargers, inverters, diesel generator (DG), relays, control devices, and interconnecting cable supplying the appropriate loads.

The AC power system consists of 4160 V switchgear OTS1; 600 V load center OXSF; 600 V motor control centers XSF, 1XSF, 2XSF, 3XSF, PXSF; 208 V motor control centers 1XSF, 1XSF-1, 2XSF, 2XSF-1, 3XSF, 3XSF-1; 120 V panel-boards KSF, KSFC.

The SSF 125 VDC Power System provides a reliable source of power for DC loads needed to black start the diesel. The DC power system consists of two 125 VDC batteries and associated chargers, two 125 VDC distribution centers (DCSF, DCSF-1), and a DC power panel-board (DCSF). Only one battery and associated charger is required to be operable and connected to the 125 VDC distribution center to supply the 125 VDC loads. In this alignment, which is normal, the battery is floated on the distribution center and is available to assure power without interruption upon loss of its associated battery charger or AC power source. The other 125 VDC battery and its associated charger are in a standby mode and are not normally connected to the 125 VDC distribution center. However, they are available via manual connection to the 125 VDC distribution center to supply SSF loads, if required.

The SSF Power System is provided with standby power from a dedicated diesel generator (DG).The SSF DG and support systems consists of the diesel generator, fuel oil transfer system, air start system, diesel engine service water system, as well as associated controls and instrumentation. This SSF DG is rated for continuous operation at 3500 kW, 0.8 pf, and 4160 VAC. The SSF electrical design load does not exceed the continuous rating of the DG. The auxiliaries required to assure proper operation of the SSF DG are supplied entirely from the SSF Power System. The SSF DG is provided with manual start capability from the SSF only. It uses a compressed air starting system with four air storage tanks. An independent fuel system, complete with a separate underground storage tank, duplex filter arrangement, a fuel oil transfer pump, and a day tank, is supplied for the DG.

3.4 Description of the Main Steam Isolation Valves (MSIVs)

The final design of the MSIVs has not been completed. However, the design will encompass, as a minimum, the following:

- One MSIV will be installed in each MS line outside the TB (downstream of the MSRVs)
- The MSIVs will meet QA-1 criteria and be seismically designed
- The MSIVs will automatically close on decreasing MS pressure
- The MSIVs will have a maximum valve closure time of 5 seconds
- The MSIVs will be capable of closing following a LOOP
- The MSIVs will be capable of closing following an SBO
- No Single Active Failure shall result in both MSIVs failing to close

(References 10.2.63 & 10.3.30)

3.5 Shutdown Intervals

The Shutdown Sequence is divided into four intervals:

1. Shutdown of the Reactor and Main Turbine
2. Establishment of stable RCS conditions
3. Initiation of RCS cooldown to ~ 250°F
4. Establishment of the Cold Shutdown Condition (RCS temperature < 200°F)

3.6 Shutdown Objectives

HELBs outside containment may or may not result in consequences that require an automatic trip of the Reactor and Main Turbine. However, in many of those cases, the operator may elect to trip the Reactor and Main Turbine for personnel and equipment protection. As such, the objective for each Shutdown interval is provided below.

1. Shutdown of the Reactor and Main Turbine
   The objective is to place the reactor in a subcritical state to protect the core. The main turbine must be tripped to prevent excessive RCS cooling. With the exception of the MS supply to the TDEFWP, the tripping of the main turbine also separates the Main Steam lines from one another by closure of the main turbine stop valves. While the capability exists to align both MS lines to the Auxiliary Steam (AS) system, administrative controls are in place to restrict such an alignment, and as such, only one of the unit's MS lines would normally be aligned to the AS system.

2. Establishment of stable RCS conditions (Safe Shutdown)
   The objective is to balance the heat generation in the RCS with the heat being removed by the Steam Generators such that RCS temperatures can be controlled. This is accomplished

by maintaining RCS inventory control and establishing RCS pressure control such that coupling with the SGs can be restored or maintained. Secondly, feeding and/or steaming of the SGs are controlled in a manner such that the amount of heat generated by core decay heat and RCP heat (if still running) is balanced with the heat removal from the SGs. Finally, a source of borated water sufficient to maintain the reactor in a subcritical condition is aligned and used to supply the RCS. Depending on the extent of damage from the HELB, stable RCS conditions may be maintained up to 72 hours[4] before plant cooldown would be initiated.

3. Initiation of RCS cooldown to ~ 250°F
   The objective of this phase is to initiate a plant cool-down from the point where RCS conditions are stabilized to LPI entry conditions. The SGs are utilized for plant cooldown from normal post reactor trip conditions to approximately 250°F. Typically plant cooldown would be via forced circulation using any RCP. If all of the RCPs are unavailable, procedures are provided to initiate a natural circulation cooldown. Natural circulation cooldown would be initiated using both SGs.

4. Establishment of Cold Shutdown Conditions (RCS temperature < 200°F)
   The objective for this phase of post-HELB operations is to transition from decay heat removal using the SGs to removing core decay heat using the LPI system. The LPI System, in conjunction with the LPSW System, is utilized to cool the RCS from approximately 250°F to less than 200°F.

3.7 Functions Needed to Meet Shutdown Objectives

This section describes the functions needed to satisfy the shutdown objectives following a postulated HELB outside containment. HELBs outside containment can be divided into two categories. Those that result in a loss of heat transfer (loss of Steam Generator feedwater) and those that result in excessive heat transfer (loss of Main Steam pressure boundary control). Loss of heat transfer events result in a mismatch where more heat is generated in the core than is removed by the secondary system. These events lead to an increase in RCS temperature and pressure. Excessive heat transfer events result in a mismatch where more heat is removed by the secondary system than is generated in the core. These events lead to a decrease in RCS temperature, pressure, and water level (due to RC shrinkage). The systems necessary to reach safe shutdown were selected based on meeting the following Shutdown functions for the two categories of HELB:

- Reactivity Control
- Reactor Coolant System Inventory Control
- Reactor Coolant System Pressure Control
- Reactor Coolant System Heat Removal Control

[4] 72 hours represents the time interval that the SSF is credited to maintain a Safe Shutdown condition.

3.7.1 Systems Needed for Shutdown of the Reactor and Main Turbine

3.7.1.1 Loss of Heat Transfer Events

Reactivity Control

Reactor power is regulated by the use of movable control rods and soluble poison dissolved in the reactor coolant. The control rods are regulated by the CRD system. The CRD System is described in UFSAR Section 7.6.1. The RPS monitors various parameters to ensure that the reactor is operating within acceptable limits. The RPS will trip the reactor to protect the reactor core from fuel rod cladding damage. The RPS also assists in protecting the RCS pressure boundary from events leading to high RCS pressure conditions. The RPS is described in UFSAR Section 7.2 (Reference 10.3.8).

Once the RPS setpoint is exceeded for these parameters, a trip signal is sent to the CRD Breakers (Reactor Trip Breakers) and the Turbine Trip System. In addition, the RPS monitors the operation of the main turbine and the Main Feedwater pumps. If either the main turbine has tripped or both Main Feedwater pumps have tripped, an anticipatory reactor trip signal would be generated within the RPS.

Shutdown of the Main Turbine is accomplished by the Turbine Trip System, via closure of the Main Turbine Stop Valves.

Reactor Coolant Inventory Control

The increase in RCS temperature results in an increase in RCS water level due to RC expansion. There are no makeup sources to the RCS credited for RCS inventory control during the initial establishment of a Safe Shutdown condition following loss of heat transfer events (Calculation OSC-6104 – Reference 10.2.32). However, a source of feedwater (EFW, PSW or SSF) to one or both SGs is required to preclude unacceptable loss of RCS inventory.

Reactor Coolant Pressure Control

The pressurizer code safety valves are credited to maintain the resultant RCS pressure below the high pressure safety limit (Calculation OSC-6104 – Reference 10.2.32).

Reactor Coolant Heat Removal Control

Prompt restoration of secondary side decay heat removal is required to prevent the RCS from going water solid. The affected Unit's EFW System is the primary means for feeding the Steam Generators. Should the affected Unit's EFW be lost as a consequence of the HELB, an alternate Unit's EFW System may be aligned to feed the SG(s). The EFW System is described in UFSAR Section 10.4.7. The HPI System has been credited for decay heat removal in cases where both main and Emergency Feedwater has been lost on an affected Unit and the Unit's 4160VAC power system is available. Should all EFW Systems be lost and 4160VAC power is not available for HPI forced cooling, the new PSW System would be credited to feed the SG(s). The PSW System is described in Section 3.2. In addition, the SSF-ASW is available as another means of feeding the SG(s) should all other sources be lost. The SSF-ASW System is described in UFSAR Section 9.6.3.3 (Reference 10.3.8).

3.7.1.2 Excessive Heat Transfer Events

Reactivity Control

The RPS monitors for low RCS pressure and a variable low pressure-to-temperature condition. Once the RPS trip setpoint is reached, a trip signal is sent to the CRD breakers. The RPS trip signal results in opening the CRD Breakers causing a loss of power to the control rod drives. The control rods drop into the core and thus shutting down the reactor. The Main Turbine is shutdown by closure of the Main Turbine Stop Valves. The Core Flood (CF) System and the HPI System would automatically inject borated water into the RCS for reactivity control to bring the reactor to a Safe Shutdown condition. The CF System contains two tanks of borated water that automatically dump into the RCS when RCS pressure decreases below approximately 600 psig. The CF System does not require any external power or initiation circuitry. The CF System is described in UFSAR Section 6.3. The HPI System is automatically actuated by the Engineered Safeguards System and injects borated water from the BWST into the RCS. The Engineered Safeguards System is described in UFSAR Section 7.3. Operation of the HPI System in the Engineered Safeguards mode is described in UFSAR Section 6.3 (Reference 10.3.8).

Additional analysis (Reference 10.2.31) has shown that if both Main Steam lines are ruptured, the reactor can be brought to a subcritical condition assuming only the negative reactivity from the inserted control rods and the borated water injected into the RCS from the CF tanks.

Reactor Coolant Inventory Control

HPI and CF have been credited for RCS inventory control during the initial establishment of Safe Shutdown conditions (Calculation OSC-6182 – Reference 10.2.5).

Reactor Coolant Pressure Control

HPI and CF injection have been credited to maintain RCS pressure (Calculation OSC-6182 – Reference 10.2.5).

Reactor Coolant Heat Removal Control

Main and Emergency Feedwater would need to be isolated to the affected SG(s) to limit the overcooling. If both Main Steam lines remain intact, the MSRVs are credited for steaming to atmosphere during the safety analysis portion of the loss of feedwater events. If either Main Steam line is ruptured upstream of the MSIV, the main turbine stop valves are credited to automatically close following the reactor trip to prevent an uncontrolled blowdown of both Steam Generators. If one or both Main Steam lines are ruptured downstream of the MSIVs, the MSIVs will automatically close to restore the main steam pressure boundary control. The AFIS circuitry is designed to automatically isolate main and Emergency Feedwater to the faulted Steam Generator. The AFIS System is described in UFSAR Section 7.9 (Reference 10.3.8).

3.7.2 Systems Needed for Establishment of Stable RCS Conditions

3.7.2.1 Loss of Heat Transfer Events

Reactivity Control

The RPS trip signal results in opening the CRD Breakers causing a loss of power to the control rod drives. The control rods drop into the core and thus shutting down the reactor. The negative reactivity inserted by the control rods is sufficient to bring the reactor to a subcritical condition and maintain subcriticality for an extended period of time without any credit for boration. However, some RCS boration would be required to offset the long term decay of Xenon-135 in the core.

Reactor Coolant System Inventory Control

Following the initial establishment of a Safe Shutdown condition, the RCS volume is controlled by isolating potential leakage pathways and making up to the system by using the HPI System or the SSF RCMU system. The seals for the reactor coolant pumps provide a barrier to RCS leakage. The HELB methodology for maintaining a Safe Shutdown condition for up to 72 hours assumes that RCP seals do not experience excessive RCS leakage as a result of the HELB. Therefore, the RCP seals must be protected against failure.

The HPI System provides the normal makeup and RCP seal injection flow as one means of assuring RCS volume control while maintaining a Safe Shutdown condition for an extended period of time. The normal letdown path would be typically in service for loss of heat transfer events to provide a letdown path back to the LDST to remove excess HPI makeup or seal injection from the RCS to control pressurizer level within limits. If the normal letdown path to the LDST is unavailable, then an alternate RCS letdown path can be aligned to the RBU via the RV head vents or the RCS high point vent valves. A pipe rupture in the RCP seal injection line could leave the RCPs without seal injection. The reactor coolant pump seals can be cooled without seal injection if Component Cooling (CC) System water continues to be supplied to the reactor coolant pump cooling jackets and seal coolers. Therefore, the CC System is considered to be needed for establishment of stable RCS conditions. However, the CC System is only needed for RCP seal injection line HELBs or for other HELBs that could interact with the RCP Seal Injection lines.

Should both the HPI and CC Systems be lost, the SSF RCMU System can supply borated water for makeup to the RCS to provide RCP seal cooling and for RCS inventory control. The SSF has the capability of isolating potential RCS leakage pathways for RCS inventory control. The SSF RCMU Pump is located in the Reactor Building basement and is powered from the SSF. The suction source for the SSF RCMU System is the Spent Fuel Pool. RCS inventory control can be accomplished from proper control of SSF-ASW flow to the Steam Generators, and proper control of the SSF RC letdown line flow. The SSF RC letdown flow is directed back to the Spent Fuel Pool.

Reactor Coolant System Pressure Control

A source of feedwater needs to be reestablished to at least one SG following loss of heat transfer events. This can be provided by the EFW system of the affected unit, if available or by another Unit's EFW System, cross connected to the affected unit, the PSW System, or SSF-ASW.

Reactor Coolant System Heat Removal Control

As previously discussed numerous sources of water may be available for feeding the SG(s). The EFW System is designed to start automatically when Main Feedwater is lost. The EFW System maintains water level in the Steam Generator for an extended period until Main Feedwater is restored or until the plant can be cooled to the point where the Low Pressure Injection (LPI) System can be placed into service. The Upper Surge Tanks (UST) provides the primary source of water for the EFW Pumps. Once the UST inventory has been depleted, the Hotwell provides the backup source of water for the EFW pumps. Suction transfer for the EFW Pumps is a manual function that does involve operator actions outside the Control Room. If condensate inventory is lost or conditions prevent a plant cooldown at the analyzed rates EFW inventory would be insufficient to cooldown to the LPI entry conditions. In either case, two alternate means, the PSW and the SSF-ASW Systems, are available for feeding the Steam Generators for long term decay heat removal.

3.7.2.2 <u>Excessive Heat Transfer Events</u>

Reactivity Control

To maintain a Safe Shutdown condition (for up to 72 hours), RCS boration must be established to compensate for the decay of Xenon-135. RCS boration is normally accomplished through the use of the HPI System. The HPI System operation is described in UFSAR Section 9.3.2. Should the HPI System become unavailable, an alternate means of supplying borated water to the RCS is available. The SSF RCMU System can be aligned to provide RCS makeup for boration. The SSF RCMU System is described in UFSAR Section 9.6 (Reference 10.3.8). The letdown paths available during this period are the normal letdown path, Reactor Vessel Head or RCS High Point Vents, or the SSF Letdown System.

Reactor Coolant System Inventory Control

The RCS inventory control function was previously described in Section 3.7.2.1 for loss of heat transfer events. For excessive heat transfer events, the normal letdown path may be automatically isolated by receipt of Engineering Safeguard system digital channels 1 or 2. Once pressurizer level has been restored, the operators would throttle HPI makeup to maintain pressurizer level at the desired set-point. The operators would then typically reestablish the normal letdown path back to the LDST to remove excess HPI makeup or seal injection flow to assist in maintaining pressurizer level within limits. If the normal letdown path is unavailable, alternate letdown flow paths, as described in Section 3.7.2.1, could be aligned.

Reactor Coolant System Pressure Control

All main and Emergency Feedwater needs to be isolated to the faulted SG to terminate excessive heat transfer for ruptures in the main steam piping upstream of the MSIVs. The MSIVs would need to be closed for ruptures in the main steam piping downstream of the MSIVs and feedwater controlled to each intact SG to terminate excessive heat transfer. A water level needs to be reestablished in the pressurizer with the ability to balance RCS makeup and letdown as described in Section 3.7.2.1 (RCS Inventory Control). Pressurizer heaters need to be restored to return the pressurizer water temperature to saturation conditions.

Reactor Coolant System Heat Removal Control

Following the initial event mitigation, operator action is taken to reestablish Main Steam pressure boundary control in both SGs to reestablish controlled secondary side heat removal. This is accomplished by closing the MSIVs (if not already closed by the event) or by closing the various Main Steam branch line isolation valves. Feedwater flow is controlled to reestablish SG water levels in the intact SG(s) at the appropriate setpoint depending on the operating status of the RCPs. Steaming of the SG(s) is accomplished via the MSRV(s) or operator action to open the ADV(s) to control MS pressure at some value below the MSRV lift setpoint. If the MSIVs cannot be closed and breaks exist in both of the Main Steam lines upstream of the branch line isolation valves, Main Steam pressure boundary control cannot be reestablished in either SG. In this case the operators would regulate the rate of feedwater to the SGs to control RCS temperature.

3.7.3 <u>Systems Needed for Initiation of RCS Cool-down to ~ 250°F</u>

3.7.3.1 <u>Loss of Heat Transfer Events</u>

Reactivity Control

Plant cool-down to the Cold Shutdown Condition requires additional boration to offset the positive reactivity effects that would be introduced by the cooldown. The HPI System is credited for boration. Boration of the RCS is accomplished through a "feed and bleed" operation. The RCS "feed" pathway is established from the HPI System. The RCS "bleed" pathway is normally established through HPI letdown path. Should the HPI letdown path be unavailable, the reactor vessel head vent or RCS high point vents would be credited for the "bleed" pathway.

Sampling of the RCS is not required for maintaining a Safe Shutdown condition. However, it is desirable to verify sufficient boron concentration has been established in the RCS prior to plant cooldown to ensure adequate shutdown margin will be maintained throughout the plant cooldown. The sampling is normally accomplished via the HPI letdown line. However, should the letdown line be unavailable, the post accident sampling system could be used to sample the RCS. The RCS post accident sampling system is described in UFSAR Section 9.3.6 (Reference 10.3.8).

Reactor Coolant System Inventory Control

Plant cool-down to LPI entry condition and the Cold Shutdown Condition require the use of the HPI System for makeup. The suction source for the HPI System is the BWST. The SSF RCMU Pump is not credited to compensate for the shrinkage of the reactor coolant during plant cooldown.

Reactor Coolant System Pressure Control

Plant cooldown to LPI entry conditions and Cold Shutdown Conditions do not require the use of the pressurizer heaters. Reduction of pressure during RCS cooldown is normally accomplished by the pressurizer spray provided by the reactor coolant pump. If the RCPs are unavailable, either the PORV or pressurizer spray (as allowed by the Technical Specifications) provided by the HPI System would need to be used to reduce RCS pressure.

Reactor Coolant System Heat Removal Control

The MS System is used to achieve normal cooldown to the LPI System decay heat removal initiation conditions. The MS Atmospheric Dump Valves are relied upon to reduce MS pressure to enable a plant cooldown. These valves are located on the turbine operating deck and are manually operated.

3.7.3.2 Excessive Heat Transfer Events

Reactivity Control

See Section 3.7.3.1 (Reactivity Control Subsection)

Reactor Coolant System Inventory Control

See Section 3.7.3.1 (RCS Inventory Control Subsection)

Reactor Coolant System Pressure Control

See Section 3.7.3.1 (RCS Pressure Control Subsection)

Reactor Coolant System Heat Removal Control

The SG(s) are used for RCS cooldown to LPI entry conditions. If the Main Steam pressure boundary control has been established, then operator action is taken to open the ADV(s) to initiate a controlled RCS cooldown. Feedwater flow is controlled by the operator to maintain SG water levels in the intact SG(s) at the appropriate setpoint depending on the operating status of the RCPs. If the Main Steam pressure boundary control cannot be reestablished in either SG, then operators would regulate the rate of feedwater to the SGs to control the RCS cooldown.

3.7.4 Systems Needed for Establishment of Cold Shutdown Conditions

3.7.4.1 Loss of Heat Transfer Events

Reactivity Control

See Section 3.7.3.1 (Reactivity Control Subsection)

Reactor Coolant System Inventory Control

See Section 3.7.3.1 (RCS Inventory Control Subsection)

Reactor Coolant System Pressure Control

See Section 3.7.3.1 (RCS Pressure Control Subsection)

Reactor Coolant Heat Removal Control

The LPI System (w/the LPSW System) is used to cool the RCS from approximately 250°F to less than 200°F. The LPI System is described in UFSAR Section 9.3.3 (Reference 10.3.8).

3.7.4.2 Excessive Heat Transfer Events

Reactivity Control

See Section 3.7.3.1 (Reactivity Control Subsection)

Reactor Coolant System Inventory Control

See Section 3.7.3.1 (RCS Inventory Control Subsection)

Reactor Coolant System Pressure Control

See Section 3.7.3.1 (RCS Pressure Control Subsection)

Reactor Coolant System Heat Removal Control

See Section 3.7.4.1 (RCS Heat Removal Control Subsection)

3.8 **Support Systems**

The Low Pressure Service Water (LPSW) System provides cooling water for normal and emergency services throughout the station. The LPSW System is described in UFSAR Section 9.2.2.1. The role of LPSW for mitigation of HELBs outside containment is to provide water to the following:

- Decay Heat Removal Coolers (to achieve the Cold Shutdown Condition)

- HPI Pump Motor Bearing Coolers
- Motor-Driven EFW Pump Motor Air Coolers
- Siphon Seal Water (SSW)

In addition to the safety-related loads, the LPSW also provides cooling water to the RCPs to allow continued operation of the RCPs during plant cooldown. Pipe ruptures in the RCP seal injection lines, would require LPSW to provide cooling to the CC cooler to support RCP seal cooling from the CC system.

The CCW System is the suction source for LPSW, PSW and SSF-ASW. The CCW System is described in UFSAR Section 9.2.2. The Essential Siphon Vacuum (ESV) System supports the CCW System by removing air from the CCW Intake Headers during normal operation and siphon modes of operation. The ESV System is described in UFSAR Section 9.2.2. The SSW System supports the ESV System by providing water to the ESV pumps. The SSW System is also described in UFSAR Section 9.2.2 (Reference 10.3.8).

The Shutdown Systems are, in general, either controlled from the Unit Control Room or from the SSF Control Room. Local manual actions such as opening of the ADVs or EFW realignments may also be required. Habitability and environmental controls for areas housing personnel and equipment needed during the Shutdown Sequence will be addressed below.

3.8.1 Habitability and Environmental Controls for the Control Areas:

Safe Shutdown can be achieved and maintained from either the Main Control Rooms or from the SSF.

The "Control Complex" includes the Main Control Rooms, the Cable Spreading Rooms, and the Electrical Equipment Rooms. These areas are equipped with HVAC to maintain room temperatures within acceptable limits for both personnel and equipment. The systems used to provide Control Complex cooling are discussed in UFSAR Section 9.4.1. These systems are non-safety related and the support systems needed to provide cooling are not protected from the effects of HELBs inside the Turbine Building. Specifically, the power supply to the air handling Units may be lost and the chilled water system may be lost due to both electrical failure of pumps and compressors and mechanical failure of piping. Analysis has shown that the Control Complex temperatures remain within acceptable limits for an extended period of time (approximately 16 hours) without the HVAC System (Reference 10.2.23). However, for long term occupancy damage repair measures would need to be taken to restore alternate means of area cooling to extend Control Room habitability during the remainder of the HELB mitigation and unit shutdown. The SSF contains its own HVAC System that is not vulnerable to the effects of HELBs inside the plant. The SSF HVAC System is described in UFSAR Section 9.6.3.6.4 (Reference 10.3.8).

3.8.2 Habitability and Environmental Controls for Other Areas:

Access to the Turbine Building may be needed for plant cooldown for operation of the ADVs and EFW realignment. The Turbine Building is equipped with a ventilation system. The ventilation system is designed to maintain a suitable environment for personnel and equipment during normal operation. The Turbine Building ventilation system is described in UFSAR Section 9.4.4. The ventilation system is non-safety and the power supply to the fans may be lost due to HELBs inside the Turbine Building. The ventilation system is not credited for HELB mitigation.

The only area in the Auxiliary Building that is susceptible to high temperatures and possible pressurization following a HELB is the penetration room. This room is equipped with blowout panels that are designed to relieve steam to outside following a HELB. The blowout panels protect the Auxiliary Building structure from damage due to pressurization effects. Flood outlet devices are also credited to release water to outside to prevent flooding of the Auxiliary Building. The equipment required to mitigate the consequences of HELBs inside the penetration room have been environmentally qualified to the conditions determined to occur following a Main Steam or Main Feedwater line break.

3.9 Power Sources

The power sources supporting the Shutdown Sequence functions are divided into three categories. They are the plant electrical system, the PSW electrical system, and the SSF electrical system.

Plant Electrical System:

Each Unit's equipment needed for achieving and maintaining a Safe Shutdown condition is supplied by the associated Unit's 4160VAC electrical switchgears (TC, TD, and TE). These switchgears are located inside the Turbine Building. The switchgears provide 4160VAC power to the HPI, EFW, LPSW, and LPI pumps. The 4160VAC distribution system is described in UFSAR Section 8.3.1.1.3 (Reference 10.3.8). The switchgears also provide power to 600VAC and 208VAC safety and non-safety related motor control centers that supply power to various motor operated valves in Shutdown Systems. These MCCs also provide power to the various battery chargers for the 125VDC and 250VDC systems. The 600VAC system and the 208VAC system are described in UFSAR Sections 8.3.1.1.4 and 8.3.1.1.5, respectively. The 4160VAC electrical switchgears are powered from two Main Feeder Buses. Either Main Feeder Bus can power switchgears TC, TD and TE. The Main Feeder Buses are also routed through the Turbine Building.

Each Main Feeder Bus is normally powered from its associated Unit's auxiliary transformer (1T, 2T, 3T) which is powered from the Unit's main generator. Following a turbine trip, the Main Feeder Buses will automatically be re-powered by the associated Unit's startup transformer (CT1, CT2, and CT3). The Unit startup transformers are normally powered from the 230kV Switchyard. The 230kV switchyard is described in UFSAR Section 8.2.1.3. The 230kV Switchyard has multiple off-site power connections that will maintain availability of power to the startup transformers. In fact, there are eight off-site transmission lines that connect to the 230 kV Switchyard. Should the station experience a complete loss of all off-site power sources, the startup transformers can be re-powered from a Keowee Hydro Unit that is aligned to the overhead power path to the yellow bus of the 230kV Switchyard. Each Unit's startup transformer is sized to carry full load auxiliaries for one nuclear generating Unit plus the engineered safeguards equipment of another Unit.

Each Main Feeder Bus can also be powered from the standby buses. The standby buses are normally de-energized. The standby buses can be automatically energized, when needed, from the other Keowee

Hydro Unit that is aligned to the underground path to transformer CT4. Should this power path be unavailable, the standby buses can be powered from transformer CT5. CT5 is normally powered via the 100 kV Central Tie Substation. The 100kV system is described in UFSAR Section 8.2.1.4. The 100kV line can be isolated from the grid and connected to dedicated combustion turbine-generators located at Lee Steam Station. The standby bus and its associated power sources are located outside of the Turbine Building. Transformer CT5 is located on the opposite side of the station from the 230 kV facilities. However, the power cables from CT5 to the standby buses are routed through the Turbine Building.

Each Unit also has a 6900 volt auxiliary power system that designed to supply power to the reactor coolant pump motors. The 6900VAC system is described in UFSAR Section 8.3.1.1.2. This system is arranged into two bus sections (TA and TB). Either the Unit Auxiliary Transformer (1T, 2T, 3T) or the Startup Transformer (CT1, CT2, or CT3) is capable of feeding both switchgear buses. During startup, shutdown and after shutdown, the switchgear buses are supplied from the Startup Transformer. The RCPs are not required for achieving and maintaining a Safe Shutdown condition. However, it is desired to operate at least one RCP for plant cooldown. If the 6900VAC power system is lost and cannot be restored, a natural circulation cooldown of the RCS would be required.

<u>125VDC Vital Instrumentation and Control System:</u>

This system provides uninterrupted 125VDC power to instrumentation and controls needed for achieving and maintaining a Safe Shutdown condition (ex. RPS and ESG). The 125VDC vital I&C system is described in UFSAR Section 8.3.2.1.1 (Reference 10.3.8). The system includes the portion of the plant auxiliary power system from the DC battery chargers (including the batteries) through the individual 125VDC Instrumentation and Control (I&C) Power Panelboards. The batteries remain charged during normal operation by their associated battery chargers. The battery chargers receive power from the Unit's 600VAC system. Following a loss of power on the 600VAC system, the batteries maintain adequate voltage on the system. However, power must be restored to the battery chargers before the batteries are drained. If the 4160VAC/600VAC distribution system has been damaged by any HELB inside the Turbine Building, power will be restored to the battery chargers from the PSW electrical system before the batteries can be drained.

<u>120VAC Vital Instrumentation and Control Power:</u>

This system provides power to plant instrumentation that would be needed by the operators to safely shutdown the reactor and to achieve and maintain a Safe Shutdown condition from the Control Room. The 120VAC vital I&C system is described in UFSAR Section 8.3.2.1.4. The system is powered from the 125VDC Vital I&C System.

<u>125/250VDC Power System:</u>

The 125/250VDC power system is described in UFSAR Section 8.3.2.1.2. The only Shutdown function supported by this system is for the EFW System. The TDEFW pump auxiliary oil pump receives power from this system to allow auto start or remote manual starting capability from the Unit Control Room. Loss of the 250VDC system would require local manual start of the TDEFW Pump.

240/120 VAC Uninterruptible Power System:

The system includes the 240/120VAC Power Panelboards, inverters, and all interconnecting cables. The system is described in UFSAR Section 8.3.2.1.5. The system provides power for panelboards KI, KX, KU and KOAC. Panelboards KI, KX and KU are powered from the 125VDC Vital I&C system, while Panelboard KOAC is powered from the 250VDC power system. These panelboards are not required during the Shutdown Sequence; however, certain equipment is powered from these sources that may be needed for plant control following the establishment of a Safe Shutdown condition.

Panelboard KI supplies ICS auto power for pressurizer level control, RCP seal injection flow indication and control, the main turbine bypass valve controls, the automatic control of the pressurizer heaters, pressurizer spray, and the PORV. This allows the ICS to automatically control these components. Due to the importance of these controls, backup power from Panelboard KU can supply power (i.e., ICS hand power) for pressurizer level control, RCP seal injection flow indication and control, and the main turbine bypass valve controls. This allows the operators to manually control the components from the Control Room using the ICS hand/auto stations.

230kV Switchyard 125VDC Power System:

The 230kV switchyard is served by a 125VDC power system. This system is described in UFSAR Section 8.2.1.5. The system provides power to 230kV switchyard PCBs for closing and tripping control. Power is supplied to the battery chargers from Unit 1 and Unit 2 4160VAC electrical distribution system.

PSW Electrical System:

A new PSW electrical system is being installed that will be protected from HELBs that could damage the existing plant electrical distribution system located inside the Turbine Building. The new PSW Electrical system will normally be powered from the 100kV transmission line that also supplies power to the existing CT5 transformer. The new PSW electrical system can also be powered from either Keowee Hydro Unit via an underground cable. The PSW electrical system will be housed in a new building not vulnerable to the effects of HELBs. This system provides power to the PSW pump and its associated equipment needed to establish and maintain feed to the SG(s). If the plant 4160VAC/600VAC/208VAC Power System is lost due to HELBs inside the Turbine Building, the PSW Electrical System provides an alternate power source for systems and components needed to achieve and maintain the plant in a Safe Shutdown condition. The systems and components that are provided alternate power from PSW electrical include:

- HPI Makeup to the RCS from the BWST
- RCP Seal Injection Flow Control
- Reactor Vessel Head Vent Valves
- RCS High Point Vent Valves
- Pressurizer Heaters
- Vital I&C Battery Chargers (CA and CB)

SSF Electrical System:

The SSF Electrical System includes 4160VAC, 600VAC, 208VAC, 120VAC, and 125VDC. The SSF Electrical System is described in UFSAR Section 9.6.3.4 (Reference 10.3.8). The SSF electrical loads are supplied by a diesel generator located inside the SSF. This system supplies the power necessary to operate SSF systems. It consists of switchgear, load center, motor control centers, panelboards, batteries, battery chargers, inverters, a diesel-electric generator unit, relays, control devices and interconnecting cables. The SSF Electrical System is contained within the SSF structure and is not subject to the effects from HELBs.

3.10 **Instrumentation**

Adequate display instrumentation is needed by the operator to establish and maintain a Safe Shutdown condition. In addition, adequate instrumentation is needed to control plant cooldown. Safe Shutdown can be maintained from either the Unit Main Control Room or from the SSF Control Room. The necessary plant instrumentation is available in both the Main Control Room and the SSF Control Room to maintain the Safe Shutdown condition. Instrumentation needed for plant cooldown is available in the Main Control Room. This instrumentation is discussed in more detail below.

3.10.1 Unit Main Control Room Instrumentation

A. The conditions inside the RCS are monitored by the following:

- RCS Pressure
- RCS Temperature
- RCS Water Level
- Degrees Subcooling
- Neutron Flux

RCS pressure indication is classified as a Type A Category 1 variable. There are two upgraded QA-1 channels of wide range RCS pressure indication. These signals are provided to control board readouts and processed through the ICCM System cabinets. The range of these readouts is 0 to 3000 psig (UFSAR Section 7.5.2.1 – Reference 10.3.8).

RCS temperature indication is provided by core exit thermocouples, hot leg temperature and cold leg temperature instruments. Core exit temperature is classified as a Type A Category 1 variable. Twenty-four Core Exit Thermocouples (CETs) have been upgraded for accident monitoring. These 24 CETs are displayed on the ICCM plasma displays in the Control Room. In addition, 5 CETs are displayed on the corresponding SSF Unit console. The range of the readouts is 50°F to 2300°F (Ref. UFSAR Section 7.5.2.2.1). RCS Hot Leg Water temperature is classified as a Type "A" Category 1 variable. Two QA-1 channels of instrumentation are provided for monitoring Wide Range RCS Hot Leg temperature. The indication readouts are located in the Control Room. The range of the readouts is 50°F to 700°F. Control Room display is through the ICCM System (Ref. UFSAR Section 7.5.2.16). RCS Cold Leg temperature is classified as a Type B Category 3 variable. There is temperature indication for each of the four cold legs. RCS Cold Leg temperature is used as a backup to Hot Leg temperature and Core Exit Temperature. Either forced or natural circulation is required in the RCS for its indication to be representative of actual core conditions. The indicated range is 50°F to 650°F (Ref. UFSAR Section 7.5.2.15). Although the cold leg temperature indication is not a Type A variable, it is a desirable parameter for the operators to verify natural circulation conditions during plant cooldown.

The RCS water level indication is provided by pressurizer level and by reactor vessel water level and hot leg water level. Pressurizer level is classified as a Type A Category 1 variable. There are three channels of QA-1 instrumentation for post accident monitoring. These readouts have a range of 0 inches to 400 inches (Ref. UFSAR Section 7.5.2.3). The pressurizer level indication is density compensated by pressurizer water temperature. Pressurizer water temperature indication is also provided. The reactor vessel level and hot leg levels are classified as Type B Category 1 variables. These water levels are displayed on the ICCM plasma displays in the Control Room. The reactor vessel and hot leg levels are only utilized when the RCS is in natural circulation conditions (Ref. UFSAR Section 7.5.2.2.3). Although reactor vessel and hot leg levels are not Type A variables, it is a desirable parameter used by the operator to verify natural circulation conditions during plant cooldown.

RCS subcooling is an important parameter used by the operator to assure achieving and maintaining a Safe Shutdown condition. "Degrees of subcooling monitoring" is classified as a Type A Category 1 variable. The hot leg subcooling margin is calculated from wide range RCS pressure measurements and individual hot leg RTD temperature measurements. The reactor core subcooling margin is calculated from the average of the five highest qualified CETs. The average value is then used with the RCS pressure measurement to calculate the subcooling margin. The readout is provided in the Control Room on the ICCM plasma display Unit. The range of the degrees of subcooling readouts is 200°F subcooled to 50°F superheat (UFSAR Section 7.5.2.2.2 – Reference 10.3.8).

Neutron flux is an important parameter used by the operators to verify the reactor is being maintained in a safe condition. There are four channels of neutron flux for the source range and wide range indication provided by NI-1, NI-2, NI-3 and NI-4. These neutron flux indications are classified as Type B Category 1 variables. These instruments are QA Condition 1 and powered from safety grade buses. The Source Range has a scale from 10^{-1} to 10^{5} CPS. The Wide Range has a scale from 10^{-8} to 200% FP. There are also rate of change meters for each of the indications with a range of -1 to +7 decades/minute (UFSAR Section 7.5.2.12 – Reference 10.3.8). Although these source and wide range flux indications are not required during for achieving and maintaining the Safe Shutdown of the reactor, these instruments are desirable for the operators during the plant cooldown phases.

B. The ability of the HPI System to provide makeup to the RCS is monitored by the following:

- Letdown Storage Tank Level
- Borated Water Storage Tank Level
- High Pressure Injection Flow
- RCP Seal Injection Total Flow

The LDST level instrumentation has been classified as a Type D Category 2 variable. There are two channels of level instrumentation available. The LDST level indication has a range of 0 inches to 100 inches (UFSAR Section 7.5.2.45 – Reference 10.3.8). Although the instruments are not classified as Type A variables, the operators use this information to either makeup to the LDST or align HPI pump suction to the BWST.

BWST level is classified as a Type A Category 1 variable. There are three QA-1 channels of level instrumentation provided for normal and post accident monitoring. Two of the three instrument channels provide input to the ICCM System cabinets. The ICCM cabinets provide input to the indicators in the Control Room. The range of the readouts is 0 feet to 50 feet (UFSAR Section 7.5.2.6 – Reference 10.3.8).

HPI System flow is classified as a Type A Category 1 variable. There are two QA-1 channels of flow instrumentation provided for post accident monitoring. Each channel inputs to an indicator via the ICCM System cabinets. Two other QA-1 instrument channels are provided for crossover flow indication. These channels directly input to indicators on the control board. The HPI System and crossover flow instrument channels monitor flow over the range of 0 gpm to 750 gpm (UFSAR Section 7.5.2.7 – Reference 10.2.3).

There is one RCP total seal injection flow instrument for each unit. The RCP total seal Injection flow instrumentation is non-safety. The Unit 1 instrumentation has a range of 0 to 75 gpm. The Unit 2 and Unit 3 instrumentation have a range of 0 to 80 gpm.

C. The conditions of the SGs as a heat sink are monitored by the following:

- Steam Generator Level
- Steam Generator Pressure

Steam generator level is classified as a Type A Category 1 variable. There are four different methods of steam generator level measurement and indication. However, only the Extended Startup Range is used for post accident monitoring. There are two of these level instruments per steam generator. The range of the indication is 0 inches to 388 inches (UFSAR Section 7.5.2.4 – Reference 10.3.8).

Steam Generator Pressure is classified as a Type A Category 1 variable. There are four QA-1 instruments, two per steam generator, for post accident monitoring. These instruments are input to the ICCM cabinets with outputs provided to indicators located in the Control Room. The range of the indication is 0 psig to 1200 psig (UFSAR Section 7.5.2.5 – Reference 10.3.8).

D. The ability of the secondary to supply water to the SGs for decay heat removal is monitored by the following:

- Upper Surge Tank Level
- Emergency Feedwater Flow
- Protected Service Water Flow

The UST level is classified as a Type A Category 1 variable. UST level indication is provided by two QA-1 instrument channels. Each UST level instrument channel is input to the ICCM System cabinets. The ICCM cabinets provide inputs to indicators in the Control Room to monitor UST level. The range of the UST level indication is 0 feet to 12 feet (UFSAR Section 7.5.2.11 – Reference 10.3.8).

EFW flow is classified as a Type D Category 1 variable. There are four QA-1 flow transmitters, two per steam generator. The indicated range for this variable is 0 gpm to 1200 gpm. The indicators are located in the Control Room (Ref. UFSAR Section 7.5.2.40). Although the instruments are not classified as Type A variables, the operators may use this information to determine proper operation of the EFW System.

PSW flow will be provided by be two QA-1 flow transmitters, one per steam generator. The indicated range for this variable will be 0 gpm to 600 gpm. The indicators are located in the Control Room. The operators may use this information to determine proper operation of the PSW System.

E. The ability of the normal decay heat removal system used to establish a Cold Shutdown Condition is monitored by the following:

- Low Pressure Injection Flow
- Low Pressure Service Water (LPSW) Flow to Low Pressure Injection (LPI) Coolers
- Decay Heat Cooler Outlet temperature

LPI System flow is classified as a Type "A" Category 1 variable. There are two QA-1 instrument channels provided for normal and post accident monitoring of LPI flow. Each channel inputs to an indicator in the Control Room via the ICCM System cabinets. These channels monitor LPI flow over a range of 0 gpm to 6000 gpm (Ref. UFSAR Section 7.5.2.8).

LPSW flow to the LPI Coolers is a Type A Category 1 variable at Oconee because the operator relies on this information following a design basis event (LOCA) to throttle LPSW flow to LPI coolers to maintain proper flow balance in the LPSW System. Two QA-1 instrumentation channels are provided (one per train). The indicated range for this variable is 0 gpm to 8000 gpm. The indicators are located in the Control Room (Ref. UFSAR Section 7.5.2.58).

Decay Heat Cooler Discharge Temperature is classified as a Type D Category 2 variable at Oconee. Each train of the LPI system contains instrumentation to monitor decay heat removal cooler discharge temperature. The range of the instrument is 0°F to 400°F (UFSAR Section 7.5.2.26 – Reference 10.3.8).

3.10.2 SSF Control Room Instrumentation

A. The conditions inside the RCS are monitored by the following:

- RCS Pressure
- RCS Temperature
- RCS Water Level

RCS pressure indication is provided by two QA-1 channels of RCS pressure instruments. In addition, one QA-1 channel of instrumentation is provided for monitoring Pressurizer pressure. The range of these readouts is 0 to 2500 psig.

RCS temperature indication is provided by core exit thermocouples, hot leg temperature and cold leg temperature instruments. There are 5 core exit thermocouples displayed on the corresponding SSF Unit console. The range of the readouts is 0°F to 1000°F. RCS Hot Leg Water temperature indication is provided by two QA-1 channels of Wide Range RCS Hot Leg temperature instruments. The range of the indication is 60°F to 650°F. RCS Cold Leg temperature indication is provided by four QA-1 channels of Wide Range RCS Cold Leg temperature instruments (one for each of the four cold legs). The indicated range is 60°F to 650°F.

The RCS water level indication is provided by pressurizer level. Pressurizer level indication is provided by one QA-1 channel of instrumentation. The range of the indication is 0 inches to 400 inches.

B. The ability of the SSF RCMU System to provide RCP seal injection is monitored by the following:

- SSF RCMU Pump Suction Pressure
- SSF RCMU Pump Discharge Pressure
- SSF RCMU Pump Discharge Flow

The SSF RCMU Pump suction pressure indication is provided by one QA-1 channel of instrumentation. The range of the suction pressure indication is 0 psig to 35 psig.

The SSF RCMU Pump discharge pressure indication is provided by one QA-1 channel of instrumentation. The range of the discharge pressure indication is 0 psig to 3000 psig.

The SSF RCMU Pump discharge flow indication is provided by one QA-1 channel of instrumentation. The range of the discharge flow indication is 0 gpm to 30 gpm.

C. The conditions of the SGs as a heat sink are monitored by the following:

- Steam Generator Level

Steam generator level indication is provided by two QA-1 channels of instrumentation (one per SG). The range of the indication is 0 inches to 388 inches.

D. The ability of the SSF-ASW system to supply water to the SGs for decay heat removal is monitored by the following:

- SSF-ASW Flow

SSF-ASW flow indication to the SG is provided by one QA-1 channel of instrumentation. The range of flow indication is 0 gpm to 600 gpm.

4.0 UNIT 1 – ANALYSIS

For Unit 1 a total of twelve (12) systems have been identified as having high energy lines and postulated break locations outside of the Containment. These systems are as follows:

- Auxiliary Steam System
- Condensate System
- Extraction Steam System
- Feedwater System
- Heater Drain System
- Heater Vent System
- High Pressure Injection System
- Main Steam System
- Moisture Separator Reheater Drain System
- Plant Heating System
- Steam Drain System
- Steam Seal Header System

These systems were identified and their break locations and break types were generated based upon the criteria provided in Section 2. The Unit 1 HE Systems, the HE Lines on these systems, and the HE boundaries for each HE piping run are identified and documented in Calculation OSC-8385 (Reference 10.2.1). The break locations, and break types for each HE piping run are compiled and documented in Calculation OSC–7516.01 (Reference 10.2.2). Additional break location details are provided in Calculation OSC-7516.02 (Reference 10.2.6), and additional information on excluded piping sections and/or break locations is provided in Calculations OSC-8385 & OSC–7516.04 (References 10.2.1 & 10.2.8, respectively). The analysis of each system follows.

4.1 High Energy Systems (HE Lines, Boundaries & Break Locations)

For each HE System the following parameters are provided:

- HE Lines
- The HE Line boundaries
- HELB locations

4.1.1 Auxiliary Steam System

The purpose of the Auxiliary Steam (AS) System is to supply steam as necessary to various plant components and systems. The AS System supplies steam for startup of the unit, when the Main Steam System is not available. In particular, the AS System provides a backup steam supply to the Turbine-Driven Emergency Feedwater Pump, and the AS System provides steam to the Condensate Steam Air Ejectors, the Main Feedwater Pump Turbines, the Steam Seal Header, the Low-Pressure Feedwater "E" Heaters and various station heating & radwaste system loads. The AS System is shared by all three ONS Units. Steam for the AS System is supplied from the Main Steam System of any Unit or an Auxiliary Boiler, which is shared with all three (3) units. A simplified functional configuration of the Unit 1 AS System is shown on Figure 4.1-1.

The high energy portions of the AS System include essentially all Unit 1 AS piping that exceeds 1" nominal pipe size. All Unit 1 AS High Energy piping is located in the Turbine Building. The major HE piping boundaries of the AS System include the isolation valves AS-7 & AS-311 on the piping lines from the Auxiliary Boiler to the two (2) Unit 1 AS headers, valves 1MS-127, 1MS-131, & 1MS-130 from the Main Steam System, and valve AS-5, which separates the Unit 1 & Unit 2 AS Systems. The 12" Unit 1 AS header downstream of Vent Valve 1AS-460 and upstream of the Unit 2 Vent Valve, 2AS-319 has a boundary with the Unit 2 AS header (12"). There is no specific boundary component for this piping header other than the pipe is routed into the Unit 2 portion of the Turbine Building. Other component boundaries for Unit 1 include valves 1AS-465, 1AS-34, 1AS-26, 1AS-38, and AS-22. There are also HE piping boundaries at the five (5) relief valves 1AS-23, 1AS-101, 1AS-455, 1AS-468, & 1AS-469 and at relief valve 1AS-10. The remaining boundary points for the Unit 1 AS System are the branch connections to the Unit 1 Main Feedwater Pump Turbine piping and the system boundary with the Plant Heating System at valves 1AS-44 & 1AS-45. Although valve 1AS-40 is closed, the AS high energy boundary is at the branch connection with the Main Steam piping downstream of 1AS-41. These boundaries are described in References 10.2.1 & 10.2.2, and these boundaries are shown graphically on Figure 4.1-1.

On the Unit 1 AS System there are 45 Running Breaks that were considered for analysis, and 42 non-excluded, Running Breaks were identified (References 10.2.1, 10.2.2, 10.2.6 & 10.2.8). A compilation of the non-excluded, Running Breaks (42) and their physical parameters are provided in Table 4.1-1. The AS System has no seismically analyzed lines, and all of the individual breaks are located in the Unit 1 section of the Turbine Building. The majority of these individual breaks are located on the basement level (775'-0" Elev.) of the Turbine Building with the remainder located on the Turbine Building mezzanine level (796'-6" Elev.). Three (3) of the Running Breaks, 1-AS-014-R, 1-AS-026-R, & 1-AS-027-R, were excluded based upon the normally closed position of valve 1AS-34 (Reference 10.2.8). The location of each of the non-excluded, Running Breaks is shown on Figure 4.1-1. There are no postulated critical crack locations on the Unit 1 AS System (Reference 10.2.2).

4.1.2 Condensate System

The purpose of the Condensate System is to deliver condensate water from the Condenser Hotwells to the suction of the Main Feedwater (MFDW) Pumps. The Hotwell and Condensate Booster Pumps raise the condensate water pressure to the net positive suction head (NPSH) of the MFDW Pumps. The Polishing Demineralizers purify the condensate water to meet the chemistry specifications of the Steam Generators, and the condensate water is heated in the Low Pressure Heaters between the Condensate Booster Pumps and the MFDW Pumps. A simplified functional configuration of the Unit 1 Condensate System is shown on Figure 4.1-2.

The high energy portions of the Condensate System include most of the Unit 1 piping that exceeds 1" nominal pipe size. All of the Unit 1 Condensate System HE piping is located in the Turbine Building. The major boundaries of the Condensate System HE piping are the discharge nozzles of the Condensate Booster pumps, the inlet and outlet nozzles of the Low Pressure heaters, and the suction nozzles on the MFDW Pumps. The other HE piping boundaries on the Condensate System include Control Valves 1C-425, 1C-426, & 1C-427; valves 1C-98 & 1C-99; valve 1C-124; and safety/relief valves 1FDW-50 & 1FDW-62. The MFDW Pump Seal Injection piping has boundaries at the seal inlet nozzles to the MFDW Pumps; valves 1C-320 & 1C-321; and MFDW Seal Injection Pump valves 1C-311, 1C-313, 1C-314 & 1C-316. The HE lines and their boundaries for the Condensate System are described in References 10.2.1 & 10.2.2 and are shown graphically on Figures 4.1-2.

For the Unit 1 Condensate System 99 Running Breaks were considered for the analysis, and 83 Running Breaks were identified as non-excluded (References 10.2.1, 10.2.2, 10.2.6 & 10.2.8). A compilation of the non-excluded, Running Breaks (83) and the location and physical parameters of each of these Running Breaks are provided in Table 4.1–2. The Condensate System has no seismically analyzed piping lines, and all of the individual breaks are located in the Unit 1 portion of the Turbine Building. Ten (10) of the Running Breaks are located on the mezzanine level (796'-6" Elev.) and the balance of the Running Breaks are located on the basement level (775'-0" Elev.) of the Turbine Building. Sixteen (16) of the Running Breaks (1-C-034-R01, 1-C-034-R02, 1-C-048-R to 1-C-051-R, 1-C-054-R to 1-C-057-R, and 1-C-060-R to 1-C-064-R) were excluded based upon either being isolated by a closed valve or not meeting the definition of a HE Line during Normal Plant Conditions. The location of each of the non-excluded, Running Breaks is shown on Figure 4.1-2. There are no postulated critical crack locations on the Unit 1 Condensate System (Reference 10.2.2).

4.1.3 Extraction Steam System

The Extraction Steam System includes:

- 'A' Extraction - supplies steam to 'A' FDW Heaters and FSRHs
- 'B' Extraction - supplies steam to 'B' FDW Heaters
- 'C' Extraction - supplies steam to 'C' FDW Heaters
- HP Turbine Exhaust (Cold Reheat - Inlet to MSRH)
- LP Turbine Inlet (Hot Reheat - Outlet from MSRH)
- 'D' Extraction - supplies steam to 'D' Feedwater Heaters
- 'E' Extraction - supplies steam to 'E' Feedwater Heaters

The purpose of the Extraction Steam (ES) System is to provide heating steam for the Condensate and Feedwater Systems, in order to heat the water being supplied to the shell side of the Steam Generators. Steam is removed from various points on the Turbine Cycle for the steam. The system can also supply steam to the Plant Heating System, if desired. A simplified functional configuration of the Unit 1 Extraction Steam System is shown on Figure 4.1-3.

The high energy portions of the ES System include most of the Unit 1 piping that operates at elevated pressures and exceeds 1" nominal pipe size. All of the Unit 1 ES System HE piping is located in the Turbine Building. The major HE piping boundaries of the ES System include connections to steam supply piping line at the (Main) Feedwater Pumps and the connection points to HP & LP Heaters. The ES System also shares boundaries with the AS System, MS System, MSRD System, PH System, and the SD System. The other HE Boundaries on the ES System include valves 1HPE-20, 1MS-117, 1MS-118, 1MS-114, 1MS-121, 1MS-113, 1MS-122, & 1HPE-35. The HE lines and their boundaries for the ES System are described in References 10.2.1, 10.2.2, &10.2.6 and are shown graphically on Figure 4.1-3.

For the Unit 1 ES System 108 Running Breaks were considered for analysis, and 78 Running Breaks were identified as non-excluded, Running Breaks (References 10.2.1, 10.2.2, 10.2.6 & 10.2.8). A compilation of these non-excluded, Running Breaks, their locations, and their physical parameters are provided in Table 4.1-3. The ES System has no seismically analyzed piping lines, and all of the individual breaks on the ES System are located in the Unit 1 Turbine Building. All but two (2) of the Running Breaks are located on the mezzanine level (796'-6" Elevation), and the remaining two (2) Running Breaks are located on the basement level (775'-0" Elevation) of the Turbine Building. Thirty (30) of the Running Breaks (1-ES-035-040, 049-054, 067-072, 088-093, 101-102, 189, 289, 292, & 293-R) were excluded based upon the lack of pressure in these piping sections. These piping sections have a normal operating pressure below atmospheric pressure (≤ 0 psig). The location and break number of each of the non-excluded Running Breaks are shown on Figure 4.1-3. There are no postulated critical crack locations on the Unit 1 ES System (Reference 10.2.2).

4.1.4 Feedwater System

The purpose of the Feedwater System (also identified as the "Main Feedwater System") is to increase the temperature and pressure of the water received from the Condensate System, so that the water can be used on the shell side of the Steam Generators. The MFDW System also controls the flow rate of the water, which is supplied to the shell side of the Steam Generators. A simplified functional configuration of the Unit 1 Feedwater System is provided in Figure 4.1- 4.

The high energy portions of the MFDW System include essentially all of the Unit 1 MFDW System piping that exceeds 1" nominal pipe size. Most of the MFDW System HE piping is located in the Turbine Building. The two (2) Main Feedwater piping lines are routed out of the Turbine Building into the Auxiliary Building, and these piping lines are routed to Containment Penetrations #25 & #27 in the EPR. The major boundaries of the high energy sections of the MFDW System include the discharge nozzles of the Main Feedwater Pumps "1A" & "1B," the connections to the "A" & "B" HP Heaters, and the Containment Penetrations #25 & #27. The other HE boundaries on the MFDW System include valves 1FDW-53, 1FDW-65, 1FDW- 262, 1FDW-263, 1FDW-279, 1FDW-280, 1FDW-283, 1FDW-74, 1FDW-76, 1FDW-200, 1FDW-38, 1FDW-47, 1FDW-374, 1FDW-94, 1FDW-96, 1FDW-384, 1FDW-97, & 1FDW-98. The HE piping lines and their boundaries for the MFDW System are described in References 10.2.1 & 10.2.2 and are shown graphically on Figure 4.1-4

For the Unit 1 MFDW System fourteen (14) Terminal End Breaks, nineteen (19) Critical Cracks, and 30 Running Breaks were considered in the analysis. The non-excluded breaks on the MFDW System include twelve (12) Terminal End Breaks, nineteen (19) Critical Cracks, and twenty-eight (28) Running Breaks (References 10.2.1, 10.2.2, 10.2.6 & 10.2.8). A compilation of these non-excluded breaks, their locations, and their physical parameters are provided in Table 4.1-4. The MFDW System piping is seismically analyzed from valves 1FDW-26 & 1FDW-21 to the Containment Penetrations, #25 & #27, respectively. This accounts for the TE & CR breaks and the number of Running Breaks on the system. The postulated break locations on the MFDW System are located in both the Turbine Building and the Auxiliary Building. Within the Auxiliary Building the MFDW System is seismically analyzed. There are two (2) postulated break locations in the Auxiliary Building, 1-FDW-027 and 1-FDW-028 at Penetrations #27 and #25, respectively, at

Elevation 828'-6". There are also two (2) Critical Cracks, 1FDW-057-CR (Elevation 828'-6") & 1-FDW-058-CR (Elevation 816'-6"), in the Auxiliary Building on the Main Feedwater piping line to Penetration #25. All of the non-analyzed piping, and hence, the Running Breaks are located in the Turbine Building on the basement level (775'-0" Elevation) and the mezzanine level (796'-6" Elevation). The MFDW System TE breaks and the CRs in the Turbine Building are also located on the basement and mezzanine levels. Two (2) Terminal End Breaks (1-FDW-015 and 1FDW-016) and two (2) Running Breaks (1-FDW-038 & 040-R) have been excluded, because they are isolated from the HE sections of the MFDW System by closed valves during Normal Plant Conditions. The location and break number of each of the non-excluded HELBs on the MFDW System are shown on Figure 4.1-4. There are no postulated critical crack locations on the non-analyzed portions of the Unit 1 Main Feedwater System (reference 10.2.2 & 10.3.17).

4.1.5 Heater Drain System

The purpose of the Heater Drain (HD) System is to collect the condensed extraction steam from the Feedwater Heaters and to transport the condensate to the Condensate System. A simplified functional configuration of the Unit 1 portions of the HD System that contain HE piping is shown on Figure 4.1-5.

The High Energy portions of the HD System consist of most of the piping on the HD System that exceeds 1" nominal pipe size. The major portions of the HD System that are not HE piping include the "E" Heater Drain Pumps suction piping from the "E" LP Heaters to the drain pumps and the HD Piping from the "F" LP Heaters to the Condenser. The major HE piping boundaries of the HD System are the two (2) connections to the Condensate System; the outlet nozzles on the Heaters, Flash Tanks and Drain Coolers; and the outlet nozzles of the Heater Drain Pumps. The other HE piping boundaries of the HD System are the numerous closed valves and relief valves. The HE Lines and their boundaries for the HD System are described in References 10.2.1 & 10.2.2 and are shown graphically on Figure 4.1- 5.

The Heater Drain System break locations consist of four (4) Terminal End (TE) breaks with two (2) of the TE breaks at the inlet to the "B" HP Heaters and the other two (2) TE Breaks on the outlets to the "C" Heater Drain Coolers. The remaining breaks are all Running Breaks. The analysis considered 137 Running Breaks, and there are 137 non-excluded Running Breaks on the Heater Drain System (References 10.2.1, 10.2.2, 10.2.6 & 10.2.8). A compilation of the non-excluded TE breaks and the non-excluded Running Breaks, their location, and physical parameters associated with each break is provided in Table 4.1-5. The Heater Drain System has no seismically analyzed piping lines, and all of the Running Breaks and the four (4) TE breaks are located in the Turbine Building. The majority of the postulated Running Breaks on the HD System are located on the basement level of the Turbine Building (775'-0" Elevation). The remaining Running Breaks are located on the Mezzanine level of the Turbine Building (796'-6" Elevation). The two (2) TE breaks on the "C" Heater Drain Coolers are located on the 803'-3" Elevation of the Turbine Building, and the two (2) TE breaks on the "B" HP Heaters are located on the 799'-6" Elevation of the Turbine Building. The location of each of the Terminal End Breaks and the non-excluded, Running Breaks are shown on Figure 4.1-5. There are no postulated critical crack locations on the Unit 1 HD System (Reference 10.2.2).

4.1.6 Heater Vent System

The purpose of the Heater Vent (HV) System is to remove non-condensable gases from the shell side of the "A", "B", "C", & "D" Heaters, the Heater Drain Coolers, and the Heater Drain lines and to transport these non-condensable gases to the Main Condenser. A simplified functional configuration of the portions of the HV System that contain HE piping is shown of Figure 4.1-6. The high energy portions of the HV System include most of the Unit 1 piping on the HV System, whose normal operating pressure is greater than atmospheric and greater than 1" nominal pipe size. All of the Unit 1 Heater Vent System piping is in the Turbine Building. The major boundaries of the HV System HE piping are the vent piping lines from the "A", "B", "C", & "D" heaters to the first closed valve, relief valve, or pressure reducing orifice. There are also two boundaries from the "C" Heater Drain Cooler drain lines to relief valves 1HV-76 & 1HV-79. Some parts of the piping on the HV System normally operates at atmospheric or sub-atmospheric pressure, and therefore, these sections of pipe are incapable of generating pipe whips, jet impingement, flooding, or compartmental pressurization effects. The HV System HE piping line sections and their boundaries are described in References 10.2.1 & 10.2.2 and shown graphically on Figure 4.1-6.

For the Unit 1 Heater Vent System 39 Running Breaks were considered (Reference 10.2.2 & 10.2.6), and there are a total of 25 non-excluded, Running Breaks on the system (References 10.2.1, 10.2.2, 10.2.6 & 10.2.8). A compilation of the non-excluded, Running Breaks, their locations, and their physical parameters are provided in Table 4.1-6. The Heater Vent System has no seismically analyzed piping lines, and all of the individual breaks on the HV System are located in the Unit 1 portion of the Turbine Building. Most of the Running Breaks are located on the mezzanine level (796'-6" Elevation) and the remaining postulated breaks are located on the basement level (775' – 0" Elevation) of the Turbine Building. Fourteen (14) of the Running Breaks (1-HV-023 to 036-R) were excluded based upon the lack of pressure in these piping sections. These Running Breaks had a normal operating pressure of less than or equal to atmospheric pressure (≤ 0 psig) (Reference 10.2.2). The location and break number of each of the non-excluded, Running Breaks are shown on Figure 4.1-6. There are no postulated critical crack locations on the Unit 1 HV System (Reference 10.2.2).

4.1.7 High Pressure Injection System

The purpose of the High Pressure Injection (HPI) System is to maintain the RCS coolant inventory (i.e. maintain RCS level), regulate the boric acid concentration in the RCS water, and maintain the RCP seal integrity. The HPI System adds RCS inventory as necessary through both the normal HPI Injection Line and through the RCP seals via the individual seal injection lines. The RCS inventory is removed through the Letdown Line. Each ONS Unit has its own HPI System. Each ONS Unit has three (3) HPI pumps, two (2) injection flow headers outside of the Containment, and the RCP Seal Injection flow paths. The only potential interface between any of the Units' HPI Systems is that the Unit 1 & Unit 2 HPI Pumps are located in the same compartment (room). A simplified functional configuration of the Unit 1 HPI System is shown on Figure 4.1-7.

With the exception of the HPI Pump mini-flow lines all of the Unit 1 HPI System piping is seismically analyzed. The high energy portions of the HPI System include:

- The HPI Pump discharge piping from the HPI Pumps 1A & 1B to Containment Penetration #9 for the HPI Injection Lines & to Containment Penetration #10A, 10B, 23A, & 23B (RCP Seal Injection Lines).
- The Letdown Line from the Containment Penetration #6 to the pressure reducing device or a closed valve
- The HPI Pump mini-flow lines for HPI Pumps 1A & 1B from the branch connection on the HPI Pump discharge line to beyond the block orifices

The RCP Seal Return Piping and the HPI Pump Suction Piping have been excluded as HE piping, because under Normal Plant Conditions the piping does not exceed the HE piping temperature or pressure limits (See Section 2.2.1). The HPI Pump 1C discharge piping from the pump to Containment Penetration #52 and its mini-flow line are excluded as HE piping with postulated HELBs, because this piping is not pressurized more than 1% of the total operating time of the unit. Also, all HPI Piping with a nominal pipe size of 1" and smaller is excluded (Reference 10.1.1)

The primary boundaries for the HE HPI Pump discharge piping are the discharge nozzles for HPI Pumps 1A & 1B, Containment Penetration #9, and the four (4) RCP Seal Injection Lines Containment Penetrations #10A & #10B (WPR) and #23A & #23B (EPR). The primary boundaries on the Letdown Line are Containment Penetration #6, closed valve 1HP-42 (Letdown Block Orifice Manual Bypass Valve), the Block Orifice (1HPIFE0040), and the isolation valve 1HP-41 (Letdown Flow Control Outlet Block Valve). The other HPI System HE pipe boundaries are valve 1HP-62 (LDST and HPI Pump Bypass Valve), valve 1HP-116 (HPI Pumps 1B/1C Discharge Header Separation Valve), and the HPI Pumps 1A & 1B mini-flow line stop check valves 1HP-248 & 1HP-250, respectively. The High Energy Piping and the boundaries of the Unit 1 HPI System are described in References 10.2.1 & 10.2.2 and are shown on Figure 4.1-7.

The Unit 1 HPI System has 14 Terminal End break locations and three (3) Running Breaks that were considered during the analysis. There are a total of 8 non-excluded, Terminal End Breaks and two (2) non-excluded Running Breaks on the system (References 10.2.1, 10.2.2, 10.2.6 & 10.2.8). A compilation of the non-excluded breaks, their locations, and their physical parameters are provided in Table 4.1-6. No other HELBs or Critical Cracks have been postulated, because no other locations on the HE piping on the HPI System exceeded the stress limits (References 10.2.1 & 10.2.6). All of the listed break locations are on the HPI Pump Discharge Piping, except for break location 1-HPI-008, which is located on the Letdown Line at Containment Penetration #6. The three (3) postulated Running Breaks, 1-HPI-015-R, 1-HPI-016-R, & 1-HPI-017-R are on the HPI Pump mini-flow lines. Because the piping on the RCP Seal Return Line did not meet the temperature or pressure criteria for a HE Line, Terminal End break, 1-HPI-011 on the RCP Seal Return Line was excluded from further analysis. The HPI Pump 1C Discharge Piping did not meet the criteria for operation in excess of 1% of the total operating time of the unit. Hence, the postulated HELBs on these lines, locations 1-HPI-009 & 1-HPI-010, were excluded as break locations. The postulated Running Break, 1-HPI-017-R on the HPI Pump 1C Mini-Flow Line, is also excluded for the same reason. Postulated break locations on the HPI Pumps Suction Piping, 1-HPI-012, 1-HPI-013, and 1-HPI-014, were excluded because the normal operating fluid conditions in this piping did not meet the definition for HE Piping (References 10.2.1 & 10.2.8). The remaining individual break locations (TEs) and Running Breaks are listed in Table 4.1-7.

4.1.8 Main Steam System

The purpose of the Main Steam System is to provide steam at specified thermodynamic conditions and at specified flow rates to the Main Turbine. The MS System is also used to remove heat from the RCS and to supply steam to the Main Feedwater and TDEFW Pumps, Condenser Air Ejectors, SSH, the 2nd Stage of the MSRH, and miscellaneous auxiliary equipment. A simplified functional configuration of the Unit 1 Main Steam System is shown on Figure 4.1-8.

The high energy portions of the MS System include essentially all of the Unit 1 MS System piping that exceeds 1" nominal pipe size. Most of the MS System HE piping is located in the Turbine Building. A section of the MS piping line from Containment Penetration #28 is routed through the Yard outside of any building before entering the Turbine Building. The other MS piping line exits the containment from Containment Penetration #26 into the EPR in the Auxiliary Building. It is then routed out of the Auxiliary Building through the Yard and into the Turbine Building. The major boundaries to the MS System include Containment Penetrations #26 & #28 and the connections to the Main Turbine, the TDEFWP, the Main Feedwater Pump Turbines, the 2nd Stage Reheaters, the steam separators, steam drains and safety valves for the Condenser Steam Air Ejectors, and the Emergency Steam Air Ejector. The MS System HE piping also has boundaries at the MSRVs, TBVs, ADVs, and valves 1MS-127, 1MS-131, & 1MS-130 to the AS System, valves 1MS-37, 1MS-38, 1AS-38, 1MS-92, 1SSH-1 & 1SSH-3. The HE piping lines and their boundaries for the Unit 1 MS System are described in References 10.2.1 & 10.2.2 and are shown graphically on Figure 4.1-8.

For the Unit 1 Main Steam System twenty-six (26) Terminal End Breaks, nine (9) Intermediate Breaks, fifty-six (56) Critical Cracks (CR), and twenty-six (26) Running Breaks were considered for analysis. The non-excluded HELBs on the MS System include twenty-three (23) Terminal End Breaks, nine (9) Intermediate Breaks, fifty-six (56) Critical Cracks (CR), and twenty-six (26) Running Breaks (References 10.2.1, 10.2.2, 10.2.6 & 10.2.8). A compilation of these non-excluded breaks, their locations, and their physical parameters are provided in Table 4.1-8. The MS System HE piping is, for the most part, seismically analyzed. The Main Steam Lines and the branch lines of the Main Steam Lines to the first isolation valve are seismically analyzed. The only non-seismically analyzed sections are the piping to the Emergency Steam Air Ejector, the piping to the Steam Separators for the Condenser Steam Air Ejectors, the piping to the Start-up Steam Header (AS System), and the piping to the Steam Seal Header System. Since most of the MS piping is seismically analyzed, this accounts for numerous TE, IB, and CRs on the system. The MS System is seismically analyzed for the HE piping in the Yard and in the Auxiliary Building. The only HELB on the MS System in the Auxiliary Building is the Terminal end Break 1-MS-065 (835'-0" Elevation) at Containment Penetration #26 in the EPR. The HELBs in the Yard are the TE Break, 1-MS-064 (853'-9" Elevation) at Containment Penetration #28 and Critical Cracks 1-MS-214-CR and 1-MS-210-CR (827'-0" Elevation). The remaining MS System HE piping break locations are in the Turbine Building. The Running Breaks are located almost exclusively on the mezzanine level (796'-6" Elevation), and the TE, IB, and CRs in the Turbine Building are found on the basement, mezzanine, and turbine operating floor levels. The three (3) Terminal End Breaks (1-MS-005, 1-MS-006, & 1-MS-007) have been excluded because they are located downstream of the TBVs. These sections of the MS piping lines downstream of the TBVs are not HE piping because they are not pressurized during Normal Plant Conditions more than 2% of the operating time of the

MS System. The location and break number of each of the non-excluded HELBs on the MS System are shown on Figure 4.1-8. There are no postulated Critical Crack locations on the non-analyzed portions of the Unit 1 Main Steam System (References 10.2.2 & 10.3.17)

4.1.9 Moisture Separator Reheater Drain (MSRD) System

The MSRD System consists of the following three sub-systems:

- Moisture Separator Reheater (MSRH) Drains
- First Stage Reheater (FSRH) Drains
- Second Stage Reheater (SSRH) Drains

Steam from the HP turbine exhaust passes through the moisture separator portion of the MSRHs, where condensate is removed from the wet steam. The condensate is routed to the MSRH Drain System. The dry steam is then heated by the FSRH tube bundle. The "A" extraction steam inside the FSRH tubes condenses as it transmits heat to the HP turbine exhaust steam. The condensate from the FSRH tubes is routed to the FSRH drain system. The steam from the HP turbine exhaust is then heated by the SSRH tube bundle before it leaves the MSRH to the LP turbine inlet. The main steam inside the SSRH tubes condenses as it transmits heat to the HP turbine exhaust steam. The condensate from the SSRH tubes is routed to the SSRH drain system.

The purpose of the MSRD System is to collect the condensate from the moisture separators and reheater tube bundles and transport the condensate back to the feedwater heaters for heat recovery. A simplified functional configuration of the Unit 1 MSRD System is shown on Figure 4.1-9.

The high energy portions of the MSRD System include most of the Unit 1 piping that exceeds 1" nominal pipe size. All of the Unit 1 MSRD System HE piping is located in the Turbine Building. The major boundaries of the MSRD System HE piping are the connections to the Moisture Separator Reheaters, Reheater Drain Tanks, Moisture Separator Drain Tank Pumps, "A" HP heaters, the Moisture Separator Drain Tank Demineralizer Heat Exchanger, and the Heater Drain piping lines. The other HE boundaries include valves 1HD-29, 1HD-30, 1HD-26, 1HD-25, 1HD-601, 1HD-102, 1HD-103, 1HD-27, 1HD-28, 1HD-56, 1HD-58, 1HD-41, 1HD-43, 1HD-56, 1HD-58, 1HD-27, and 1HD-28. The HE piping lines and their boundaries for the MSRD System are described in References 10.2.1, 10.2.2, & 10.2.6 and are shown graphically on Figure 4.1-9.

For the Unit 1 MSRD System 30 Terminal End Breaks, two (2) Intermediate Breaks, and 138 Running Breaks were considered for analysis, and all of these postulated breaks, except for six (6) running breaks, were identified as non-excluded. The 30 Terminal Ends (non-excluded) have 28 of the TE breaks at the connections to the Moisture Separator Reheaters and Reheater Drain Tanks. For the other two (2) TE Breaks, 1-MSRD-022 is at a branch line, and 1-MSRD-045 is at an anchor. There are also two (2) Intermediate Breaks (non-excluded) on the Reheater Drain Tank condensate piping. The remaining postulated HELBs are Running Breaks. There are 132 non-excluded, Running Breaks (References 10.2.1, 10.2.2, 10.2.6 & 10.2.8). A compilation of all types of postulated breaks on the MSRD System, their locations, and physical parameters is provided in Table 4.1-9. The MSRD System has no seismically analyzed piping lines, and all of the postulated break locations are located in the Turbine Building. The postulated MSRD System breaks are located on the basement and mezzanine floors of the Turbine Building. Six (6) Running Breaks were excluded from evaluation (1-MSRD-064, 065, 114, 128, 135, & 148-R) because their normal operating pressure was sub-atmospheric, and they could not cause any HELB adverse effects. The locations of each of the postulated MSRD System break locations are shown on Figure 4.1-9. There are no postulated critical crack locations on the Unit 1 MSRD System (Reference 10.2.2).

4.1.10 Plant Heating System

The purpose of the Plant Heating (PH) System is to distribute low pressure steam (~27 psig) to space heaters, Air Handling Units (AHUs), Reactor Building Purge Heaters, Condensate Storage Tanks, and the Auxiliary Boiler. The PH System also supplies steam to the Main Steam, Main Steam Turbine Bypass, and the Main Feedwater Pump pumping traps. A simplified function configuration of the Unit 1 Plant Heating System is shown on Figure 4.1-10.

The high energy sections of the PH System include essentially all of the PH System Piping greater than 1" in nominal pipe size on the supply side (inlet side) of the equipment supplied with steam. The PH System HE piping is located in the Turbine Building and the Auxiliary Building. Some of the PH System piping extends into the Service Building (Administration Building), but no breaks were postulated on this piping. This is because there were no Shutdown Targets in the Service Building, and there were no indirect effects that could affect the Shutdown Sequence of the Unit. The major boundaries of the PH System HE piping include the AS System steam supply lines at valves 1AS-44 & 1AS-45; the connections of the Unit 1 PH System piping with the Unit 2 PH System piping, and the connections to the equipment supplied by the PH System. Other boundaries include valves 1AS-483, 1AS-47, 1AS-56, 1AS-70, 1AS-75, 1AS-73, 1AS-78, 2AS-69, AS-55, 1HPE-35, and PH-123. The HE piping line sections and their boundaries are described in References 10.2.1 & 10.2.2 and are shown graphically on Figure 4.1-10.

On the Unit 1 Plant Heating System there are 92 Running Breaks that were considered for analysis, and 90 non-excluded, Running Breaks were identified (References 10.2.1, 10.2.2, 10.2.6 & 10.2.8). A compilation of these non-excluded, Running Breaks, their locations, and their physical parameters are provided in Table 4.1-10. The PH System has no seismically analyzed lines, and majority of the individual breaks are located in the Unit 1 section of the Turbine Building. The remaining HELBs on the PH System are located in the Auxiliary Building. In the Auxiliary Building three separate PH System HE piping lines are run. The physical routing of each piping line is as follows:

- From the Turbine Building directly into the Ventilation Equipment Room – 505.
- The Reactor Building Purge Heater steam supply line is routed through the East and West Penetration Rooms.
- From the Turbine Building into the Lobby (Room 507) outside of the Control Room complex, through Room 508, and up into the Ventilation Equipment Room – 602.

Two (2) of the Running Breaks, 1-PH-019-R and 1-PH-056-R, were excluded. Running Break 1-PH-019-R was excluded because this section of the PH System is isolated from the rest of the PH System by check valve AS-55, and Running Break 1-PH-056-R is excluded because it is isolated from the rest of the PH System by closed valve 1PH-123 (Reference 10.2.8). The location of each of the non-excluded, Running Breaks and their designated identification numbers are shown on

Figure 4.1-10. There are no postulated critical crack locations on the Unit 1 PH System (Reference 10.2.2).

4.1.11 Steam Drain System

The purpose of the Steam Drain (SD) System is to remove condensate from the Main Steam System, Extraction Steam system, and the Steam Seal Header System. A simplified functional configuration of the SD System is shown of Figure 4.1-11. Since the SD System is directly connected to the MS, ES, & SSH Systems the SD piping is shown on the diagrams for these other systems.

The high energy portions of the Steam Drain System are, in general, those sections, directly connected to the HE sections of the MS, ES, & SSH Systems. The HE piping line identified sections of the SD System extend to a closed valve, steam trap, or an excluded section of piping that is 1" or less in nominal pipe size. The extent of the HE piping lines and their boundaries are described in References 10.2.1 & 10.2.2 and are shown graphically on Figure 4.1-11.

On the Unit 1 SD System ten (10) Terminal End Breaks, one Intermediate Break, four (4) Critical Cracks, and 90 Running Breaks were considered for analysis. Of these ten (10) Terminal End Breaks, one Intermediate Break, four (4) Critical Cracks, and fifty (50) Running Breaks were identified as non-excluded (References 10.2.1, 10.2.2, 10.2.6 & 10.2.8). A compilation of these non-excluded postulated HELBs, their physical location, and their physical parameters are provided in Table 4.1-11. All of the individual breaks are located in the Unit 1 portion of the Turbine Building. Three (3) of Running Breaks, one Terminal End Break, and one Critical Crack are located on the basement level (775'-0" Elev.), and the balance of the postulated breaks are located on the mezzanine level (796'-6" Elev.). Forty (40) postulated Running Breaks on the SD System have been excluded as HE line break locations. Twenty-four (24) of the excluded Running Breaks have been excluded because they are connected to a piping line with an internal pressure at atmospheric pressure (~0 psig). The remaining excluded Running Breaks on the SD System are excluded because they are connected to a section of the MS System that had been excluded as HE piping. The locations of the SD System postulated HELBs and their break numbers are shown on Figure 4.1-11. There are no postulated Critical crack locations on the non-analyzed portions of the Unit 1 SD System (References 10.2.2 & 10.3.17)

4.1.12 Steam Seal Header System

The purpose of the Steam Seal Header (SSH) System is to provide steam to the Low Pressure Turbine (Main Turbine) seals and the (Main) Feedwater Pump Turbine seals to prevent in leakage of air into the turbines. A simplified functional configuration of the Unit 1 SSH System is shown on Figure 4.1.-12.

The high energy sections of the SSH System include all of the inlet piping to the Main Feedwater Pump Turbines, the inlets to the Low Pressure Turbines, the connection to the Main Steam System, and the connection to the Auxiliary Steam System at valve 1AS-10. The other HE piping boundaries on the SSH System include valves 1SSH-1, 1SSH-3, 1SSH-8, 1SSH-9, 1SSH-14, 1SSH-

15, 1SSH-19, and 1SSH-22. The HE piping lines and their boundaries are described in References 10.2.1 & 10.2.2 and are shown graphically on Figure 4.1-12.

The analysis considered fifty-three (53) Running Breaks on the SSH System, and there are a total of twenty-nine (29) non-excluded, Running Breaks on the Unit 1 SSH System (References 10.2.1, 10.2.2, 10.2.6 & 10.2.8). There are no other types of HELBs on the SSH System, because the SSH System has no seismically analyzed piping lines. A compilation of the non-excluded, Running Breaks, their location, and their physical parameters are provided in Table 4.1-12. All of the individual breaks are located in the Unit 1 section of the Turbine Building. All but three (3) of the Running Breaks are located on the Mezzanine Level (796'-6" Elevation) of the Turbine Building, and the other three (3) Running Breaks are located on the Basement Level (775'-0" Elevation) of the Turbine Building. Twenty-four (24) postulated Running Breaks (1-SSH-001, 009-013, 033-049, & 052-R) were excluded as having postulated HELBs on them. These Running Breaks were excluded because during Normal Plant Conditions these sections of piping are operating below atmospheric pressure (~0 psig) (Reference 10.2.1). There are no postulated critical crack locations on the Unit 1 SSH System (Reference 10.2.2).

4.2 Interaction Analysis

For each of the systems listed in the previous section the interactions with the Shutdown Equipment and the defined pathway, for achieving and maintaining a Safe Shutdown condition and then proceeding to the Cold Shutdown Condition, are provided. Because of the large number of individual break locations an analysis for each break is not provided. Instead the individual breaks are grouped according to their effects on the Shutdown Equipment and a pathway to achieving a Safe Shutdown condition and then proceeding to the Cold Shutdown Condition is described for each group. A comprehensive evaluation of each individual non-excluded break location on each of the HE Systems in Unit 1 is provided in Calculations OSC-7516.04, OSC-7516.08, & OSC-7516.10 (References 10.2.8, 10.2.11, & 10.2.13). Input for these evaluations was generated in Calculations OSC-7516.01, OSC-7516.02, OSC-7516.06, OSC-7516.07 & OSC-7516.09 (References 10.2.2, 10.2.6, 10.2.9, 10.2.10, & 10.2.12)

There are six (6) areas of Unit 1, where HELBs are postulated. These areas are as follows:

- East Penetration Room (Auxiliary Building)
- West Penetration Room (Auxiliary Building)
- HPI Pump Room (Auxiliary Building)
- Ventilation Equipment Rooms 505 & 602, Lobby Area Room 507, Room 508, & Room 400B (Auxiliary Building)
- Station Yard
- Turbine Building

It should be noted that Section 4.2 provides the interaction analysis of only the Unit 1 postulated HELBs and their effects on the ONS. A description of the HELB interactions for each system in each area follows. Each postulated HELB with identified targets is listed in the Shutdown Interaction Tables, 4.2-1 to 4.2-11. These tables identify all of the Shutdown Equipment damaged by individual HELBs. The direct effects from pipe whip and jet impingement, as well as the collateral damage created by the structural component failure, have been included in these tables. The HPI System has postulated HELBs in three (3) different areas of the Auxiliary Building, and its interaction Table is 4.2-7. The Feedwater System, Main Steam System, and the Plant Heating System have postulated HELBs both in the Turbine Building and the Auxiliary Building. The Main Steam System is the only HE System in the Yard. The interaction tables for these systems are Tables 4.2-4, 4.2-9 & 4.2-10, respectively. The Steam Seal Header System has no table, because the SSH System has no direct interactions with any Shutdown Equipment.

4.2.1 HELB Interactions in the Auxiliary Building & Station Yard

4.2.1.1 HELB Interactions in the East Penetration Room

The information in this section describes the HELBs that affect the Shutdown Equipment in the East Penetration Room and the pathway for achieving and maintaining a Safe Shutdown condition and subsequent cooldown to the Cold Shutdown Condition for these HELBs. The information is separated by HE System with a write up for each system. The only HE Systems in the East Penetration Room are the Main Steam System, the (Main) Feedwater System, Plant Heating System, and the High Pressure Injection System. A detailed discussion of the postulated HELBs for these systems and their interactions are provided.

4.2.1.1.1 High Pressure Injection System

There are four (4) postulated HPI HELBs in the EPR. These breaks are the TE break on the HPI Charging Line at Containment Penetration #9 (1-HPI-007), the TE breaks on the RCP Seal Injection Lines at Containment Penetrations # 23A & #23B (1-HPI-003 & 1-HPI-006, respectively), and the TE break on the Letdown Line at Containment Penetration #6 (1-HPI-008). For any of these postulated break locations a pathway to the Safe Shutdown/Cold Shutdown Conditions exists.

For the Seal Injection Line breaks once either of the breaks occurs, the detection of the break would be made by the alarm of high seal flow in one of the lines and low flow in the other three lines. The break would be isolated by taking manual control of valve 1HP-31 and closing this valve from the Control Room. If valve 1HP-31 (RCP Seal Flow Control Valve) fails to close from the Control Room, operators can isolate the break by closing manually operated valves, which are located outside of the break area (Reference 10.3.20). Since the Component Cooling System is available, RCP seal cooling is not lost. Moreover, any flooding in the EPR would remain in the EPR for a significant period of time. The flood level in the EPR would not exceed the top of the curb around the Flood Outlet Device (FOD) for 1 hour and 40 minutes (References 10.2.20 & 10.2.24). Hence, sufficient time exists to get the seal injection line isolated. Damage to the valve 1HP-26 (1A High Pressure Injection Valve) results in loss of function to the valve, but the valve is not needed for these postulated HELBs.

Because the Seal Injection flow is normally from the Letdown Storage Tank (LDST) or possibly from the BWST, the temperature of the water would have a maximum temperature of approximately 100-105°F. This temperature water flowing out of the break would not flash to steam and cause compartmental pressurization in the EPR. Without the compartmental pressurization, the water and any radioactive materials in the water would remain in the EPR.

Upon isolation of the break, the EPR could be drained to the Low Activity Waste Tank, and the ruptured RCP Seal Injection line is isolated from the rest of the HPI System. Seal injection flow could then be restored to the other three seal injection lines. Unit shutdown would be conducted with all of the identified Shutdown Systems available. Shutdown from the Initial Plant Conditions to the Cold Shutdown Condition can be achieved.

For the HPI Charging Line Break at Containment Penetration #9, the HELB would be detected by the loss of inventory from the LDST and the low pressure in the HPI Discharge. In addition to the initial break on the Charging Line, this ruptured pipe could also whip into the two (2) RCP Seal Injection Lines in the EPR and rupture both lines. This results in loss of the Seal Injection flow to the RCPs. However, RCP seal integrity is not affected, because the Component Cooling System is not affected and would be available to maintain seal integrity. The postulated HELB is isolated by taking remote manual control of valves 1HP-120 (RC Volume Control Valve) and 1HP-31 (RCP Seal Flow Control Valve), if necessary, from the Control Room, and closing these valves.

If valve 1HP-31 fails to close from the Control Room, operators can isolate the break by closing manually operated valves, which are located outside of the break area (Reference 10.3.20). If valve 1HP-120 cannot be closed from the Control Room, operators are directed to isolate the break by closing 1HP-115 (HPI Pumps 1A & 1B Discharge Header Cross Connection Isolation Valve) and stopping the HPI Pumps. These actions can be performed from the Control Room. These actions will significantly reduce the break flow rate. However, flow will continue through the break until the break is isolated by closing a manually operated valve on the discharge of the HPI pump. This manually operated valve is located outside of the break area. With the break and the potential secondary breaks isolated, the HPI charging flow could be restored through the alternate charging line with, at least, two (2) HPI Pumps available and two throttling valves (1HP-27 & 1HP-409) available. Any flooding in the EPR could then be drained to the Low Activity Waste Tank, and the individual ruptured RCP Seal Injection lines could be isolated from the rest of the HPI System. It should be noted that this configuration allows the LDST to remain aligned to the HPI Pumps suction header to prevent overflow of the LDST to other areas of the Auxiliary Building.

As a result of this HELB on the Charging Line at Penetration #9, the EPR would flood to above the FOD curb in approximately 10.6 minutes (Reference 10.2.24), if the break had not been isolated. At this time water from the LDST and possibly the BWST would begin to flow out of the Auxiliary Building. The radiological consequences of the flooding would be bounded by the Letdown Line Break, because of the much smaller source term.

Following the isolation of the charging line break by using valve 1HP-120 or a manually operated valve on the HPI discharge piping outside of the break area and the isolation of the seal injection lines, Unit shutdown would be conducted. All of the identified Shutdown Systems would be available except for portions of the Unit 1 EFW System. This postulated HELB could cause the loss of valve 1FDW-315 (SG 1A EFW Control Valve), and without valve 1FDW-315 the EFW System could not feed the "A" Steam Generator. The "A" Steam Generator could still be supplied from the Unit 1 Main Feedwater System, the SSF, or the PSW. The ability to feed the "B" Steam Generator is unaffected. Shutdown from the Initial Plant Conditions to the Cold Shutdown Condition can be achieved.

There is one other postulated HPI HELB in the EPR. There is a postulated TE break at the Letdown Line Containment Penetration #6. This break does not interact with any other SSD equipment, but the detection and isolation of the Letdown Line is important, since the isolation of the Letdown Line would eliminate the loss of RCS inventory.

Upon rupture of the Letdown Line, the flow from the break will enter the EPR. The Letdown Line break flow will flash to steam. The EPR blowout panels were postulated to fail, so that a conservative offsite dose would be calculated (Reference 10.2.26). The Letdown line break results in a relatively fast depressurization of the RCS as primary inventory is lost through the break (See Section 7.3 of this report). With the RCS pressure decreasing, a reactor trip is initiated on either the low RCS pressure or on variable low pressure trip function. The continued RCS pressure reduction results in the RCS pressure dropping to the Engineered Safeguards actuation point. The Engineered Safeguards System actuation isolates the break by closing valves 1HP-3 (1A Letdown Cooler Outlet & Containment Isolation Valve) and 1HP-4 (1B Letdown Cooler Outlet & Containment Isolation Valve). If the Single Active Failure is either a 1HP-3 or 1HP-4 failure to close, procedures are provided to have valves 1HP-1 (1A Letdown Cooler Inlet Isolation Valve) and 1HP-2 (1B Letdown Cooler Inlet Isolation Valve) closed to isolate the break. The procedures are updated to assure that if an SAF of either 1HP-3 or 1HP-4 occurs, isolation by closing 1HP-1 and 1HP-2 is conducted prior to exceeding offsite or Control Room dose limits (References 10.2.25 &10.2.26). Following the isolation of the Letdown Line, unit shutdown would be conducted with the normal Shutdown Systems available. Shutdown from the Initial Plant Conditions to the Cold Shutdown Condition can be achieved (See Section 7.3 of this report).

4.2.1.1.2 Feedwater System

Both the 1A and the 1B Main Feedwater lines pass through the EPR. Each Main Feedwater line contains an isolation check valve. The purpose of the check valve is to provide SG pressure boundary integrity for breaks upstream of the isolation check valve. Should a break occur downstream of the feedwater isolation check valve (i.e., between the check valve and the SG), the plant response would be similar to a loss of Main Feedwater event (Reference 10.2.27) except one SG will not have an intact pressure boundary. Should a break occur upstream of the feedwater isolation check valve, the check valve will close to prevent the blowdown of the SG. Both SGs will have intact pressure boundaries. The plant response would be comparable to a loss of Main Feedwater event.

The only postulated break in the Main Feedwater piping inside the EPR is at the terminal end of each Main Feedwater pipe (identified as 1-FDW-027 and 1-FDW-028). A break at this location is downstream of the feedwater isolation check valve. The analysis of this break is similar to that of a loss of Main Feedwater event. The analysis for a feedwater line break at this location is described in OSC-7726 (Reference 10.2.27). The RPS would trip the reactor on high RCS pressure. The main turbine would trip causing the main turbine stop valves to close, separating the Main Steam lines such that only one SG would continue to blowdown. Main and Emergency Feedwater would be automatically terminated to the faulted SG by AFIS. RCS pressure will not decrease to the point where Engineered Safeguards System Digital Channels 1 and 2 would actuate the HPI System. However, the HPI System is credited for normal makeup and RCP seal injection. The HPI System may also be needed for core decay heat removal following a single active failure to the EFW flow control valve to the intact SG. A single active failure on the EFW flow control valve to the intact SG would result in a loss of secondary side decay heat removal. Operator actions would need to be taken to restore a source of feedwater to the intact SG. Either the PSW or the SSF Systems could be used as a source to provide secondary side cooling to the intact Steam Generator.

There is no damage from the direct effects (pipe whip and jet impingement) to systems, structures or components needed to mitigate the consequences of these breaks. Whip restraints have been installed at these postulated break locations to prevent pipe whip. Guard pipes have been installed around the break location to limit and direct break flow away from critical equipment inside the EPR (Reference 10.2.34). Blowout panels have been installed in exterior walls of the EPR that are designed to relieve steam from the feedwater line breaks to outside. The blowout panels are designed to limit the pressure inside the penetration rooms to prevent structural failure due to compartmental pressurization. However, a number of unreinforced block walls are assumed to fail. Their failure would result in unacceptable flooding consequences for other areas in the Auxiliary Building. This adverse consequence has been addressed by plant modifications. A Flood Outlet Device has been installed inside the EPR to release water to outside to prevent flooding of critical electrical equipment inside the EPR. Flood barriers have been installed inside the EPR to address the failure of the unreinforced block walls. The flood barriers act to contain water inside the room so that it can be directed to the FOD and to limit the amount of water that could be released to other areas of the Auxiliary Building.

Adverse environmental conditions will be created inside the penetration room. The environmental profiles have been determined. The electrical equipment required during the Shutdown Sequence and located inside the penetration rooms, have been evaluated (Calculation OSC-8505, Reference 10.2.17) to the calculated environmental conditions and have been found to be acceptable. In addition, the non-safety control systems that could be affected by the harsh environment inside the EPR have been evaluated and determined to have no significant impact to the safety analysis.

"Critical Cracks" have been postulated the "B" Main Feedwater piping lines inside the EPR. These cracks are postulated downstream and upstream of the Main Feedwater isolation check valves. Unlike the postulated Main Feedwater line breaks, guard pipes are not installed at these locations. Therefore, the effects of jet impingement had to be analyzed. Only one critical crack (1-FDW-058-CR) was found to have an adverse effect on Shutdown Equipment. This critical crack is located upstream of the 1B Main Feedwater isolation check valve. The ensuing jet from this critical crack impacts the cabling for 1HP-410 (HPI Crossover to 1A HPI Header). The HPI function is still satisfied by two HPI pumps through two injection headers utilizing 1HP-26 (1A HPI Valve) and 1HP-27 (1B HPI Valve). The adverse effects from Critical Crack, 1-FDW-057-CR, downstream of the Main Feedwater Isolation valve are bounded by the Terminal End Breaks 1-FDW-027 & 1-FDW-028.

The environmental effects created by the postulated critical cracks are bounded by the postulated Main Feedwater line breaks. The environmental effects created by either the Main Feedwater line breaks or the critical cracks in Main Feedwater piping may lead to a loss of all pressurizer heaters with the exception of Bank 2 Groups B and C heaters. Bank 2 Group B heaters can be controlled from the plant Control Room. Both groups (B and C) can be controlled from the SSF Control Room (if control has been transferred to the SSF). If the heat loss from the pressurizer exceeds the capacity of the remaining group B heaters, a plant cooldown would be initiated from the plant Control Room.

4.2.1.1.3 Main Steam System

Only the 1A Main Steam Line passes through the EPR. The only postulated break in the Main Steam piping inside the EPR is at the terminal end of the 1A Main Steam pipe (identified as 1-MS-065). The analysis for a MSLB is described in UFSAR Section 15.13. The RPS would trip the reactor on low or variable low RCS pressure. The main turbine would trip causing the main turbine stop valves to close, separating the Main Steam lines such that only one SG would continue to blowdown. Main and Emergency Feedwater should be automatically terminated to the faulted SG by AFIS. However, if feedwater flow continued to the faulted SG, the faulted SG would continue to depressurize the RCS to the point where Engineered Safeguards System Digital Channels 1 and 2 would actuate the HPI System. RCS pressure continues to decrease to the point where the CF tanks automatically inject borated water into the RCS. RCS pressure may decrease to the point where Engineered Safeguards System Digital Channels 3 and 4 actuate the LPI System. However, the LPI System is not credited in the mitigation of an MSLB.

There is no damage from the direct effects (pipe whip and jet impingement) to systems, structures or components needed to mitigate the consequences of these breaks. Blowout panels have been installed in exterior walls of the EPR that are designed to relieve steam from a Main Steam line break to outside. The blowout panels are designed to limit the pressure inside the EPR & WPR to prevent structural failure.

Adverse environmental conditions will be created inside the EPR. The environmental profiles have been determined. The electrical equipment required during the Shutdown Sequence, located inside the penetration rooms have been evaluated (Calculation OSC-8505, Reference 10.2.17) to the calculated environmental conditions and have been found to be acceptable. In addition, the non-safety control systems that could be affected by the harsh environment inside the penetration room have been evaluated and determined to have no significant impact to the safety analysis.

The environmental effects created by the Main Steam line break may lead to a loss of all pressurizer heaters with the exception of Bank 2 Groups B and C heaters. Bank 2 Group B heaters can be controlled from the plant Control Room. Both groups (B and C) can be controlled from the SSF Control Room (if control has been transferred to the SSF). If the heat loss from the pressurizer exceeds the capacity of the remaining group B heaters, a plant cooldown would be initiated from the plant Control Room.

4.2.1.1.4 Plant Heating System

The Plant Heating System HE piping in the EPR is excluded from analysis. The section of piping is isolated in the Turbine Building at valve 1AS-182 during Normal Plant Conditions. Hence, HELBs are not required to be postulated on the Plant Heating System piping lines in the EPR.

4.2.1.2 HELB Interactions in the West Penetration Room

The information in this section describes the HELBs that affect the Shutdown Equipment in the West Penetration Room and the pathway for achieving and maintaining a Safe Shutdown condition and subsequent cooldown to the Cold Shutdown Condition for these HELBs. The information is separated by HE System with a write up for each system. The only HE Systems in the West Penetration Room are the HPI System and the Plant Heating System.

4.2.1.2.1 High Pressure Injection System

There are two (2) postulated HELBs in the West Penetration Room. These two (2) breaks are the TE breaks on the RCP Seal Injection Lines at Containment Penetrations # 10A & #10B (1-HPI-004 &1-HPI-005, respectively). The detection, isolation, and Unit shutdown for an RCP Seal Injection line break in the WPR would be the same as that for a RCP Seal Injection line break in the EPR with one difference. Because of the smaller size of the WPR, the flooding of the WPR would not have the same scenario. The WPR has an emergency exit door and stairwell, which leads to the outside of the Auxiliary Building. Immediately in front of the door is a 5.75 inch flood barrier that would retain any flood water in the WPR as long as the level did not exceed 5.75 inches. Based upon the postulated HELBs in the WPR the flooding would start to enter the stairwell approximately 1 hour and 4 minutes after the initiation of the HELB (Reference 10.2.24). This is sufficient time to isolate the HELB.

Upon isolation of the break, the WPR could be drained to the LPI Room 62 Sump Pumps A & B and then pumped to the High Activity Waste Tank. The ruptured RCP Seal Injection line would be isolated from the rest of the HPI System. Seal injection flow could then be restored to the other three seal injection lines. Unit shutdown would be conducted with all the identified Shutdown Systems available without impact to these Shutdown Systems. Shutdown from the Initial Plant Conditions to the Cold Shutdown Condition can be achieved.

4.2.1.2.2 Plant Heating System

The Plant Heating System HE piping in the WPR is excluded from analysis. The section of piping is isolated in the Turbine Building at valve 1AS-182 during Normal Plant Conditions. Hence, HELBs are not required to be postulated on the Plant Heating System piping lines in the WPR.

4.2.1.3 HELB Interactions in the HPI Pump Room

The information in this section describes the postulated HELBs that affect the Shutdown Equipment in the HPI Pump Room and the pathway for achieving and maintaining a Safe Shutdown condition and subsequent cooldown to the Cold Shutdown Condition for these HELBs. The only HE System in the HPI Pump Room is HPI System itself, and only HPI System High Energy Lines are in the HPI Pump Room. No discussion is required for any other system.

There are four (4) postulated HPI HELBs in the HPI Pump Room. These HELBs include the Terminal end breaks on the HPI Pump discharge Nozzles (1-HPI-001 & 1-HPI-002) and the breaks on the mini-flow recirculation line for HPI Pumps 1A &1B (1-HPI-015-R & 1-HPI-016-R). For these four (4) postulated HELBs the other HPI Pumps and their throttling valves are not impacted by pipe whips or jet impingements. As such, the redundancy in the HPI System is not lost. Hence, there is no loss in the capability to achieve a Safe Shutdown condition or to have Unit 1 achieve the Cold Shutdown Condition. The only adverse interaction from these breaks is the flooding in the HPI Pump Room. A discussion of this interaction follows.

For a postulated HELB at the discharge nozzle of the HPI Pump, the immediate response is the loss of charging flow and the auto-start of a second HPI Pump. Upon the start of the second HPI Pump, the charging flow would be restored to the RCS. The HPI Pump, on which the HELB is postulated, would immediately increase flow to its full run out flow at the cavitation condition. At this flow rate the minimum time to flood the HPI Pump Room to an unacceptable level is 39 minutes (Reference 10.2.21). However, there is sufficient time to identify the HPI Pump that is operating at run out conditions and trip that HPI Pump. At these run out conditions the flow is approximately 650 gpm, and once tripped, the flooding rate is reduced to approximately 35 gpm (Reference 10.2.21). This reduction would give plant personnel sufficient time to isolate the break.

The postulated HELB at the discharge nozzle of an operating HPI Pump can be quickly detected and diagnosed. There would be alarms related to low HPI header pressure, low flow in the RCP Seal Injection Lines, a low level alarm for the LDST, and an alarm when HPI suction is automatically transferred to the BWST. Moreover, the Control Room indication would show two (2) HPI Pumps operating. The HPI Pump, on which the HELB occurred, would be the pump in the "ON" position, and this pump would be manually tripped. The HPI Pump that automatically started on loss of charging flow would have its control switch in the "AUTO" position. Thus, the operator would know which pump to trip (Reference 10.3.32).

Once the break location has been identified, the affected HPI Pump would be tripped by the operator. If the HPI Pump 1A had the postulated HELB, the HELB would be isolated by closing valve 1HP-103 (1A HPI Pump Suction Valve). If the break is postulated on the 1B HPI Pump, the break would be isolated by closing valve 1HP-107 (1B HPI Pump Suction Valve). Closure of the suction valve on the affected HPI Pump suction piping line is necessary to allow the LDST to stay aligned to the HPI Pump suction piping, and thus, prevents an overflow of the LDST inventory. If the SAF is either 1HP-103 or 1HP-107, a second valve is provided in series with these valves on the HPI Pump suction line. With this planned modification, described in Section 9.0 of this report, the operators can isolate the break with redundant isolation valves that do not require entry into the HPI Pump Rooms. By isolating the postulated HELB with the HPI Pump suction valve, both of the remaining HPI Pumps are available to supply charging flow and RCP Seal Injection flow. In addition, any SAF of an HPI MOV on the HPI Pump suction piping would not adversely affect the isolation of the postulated HELB or the ability to provide borated water from either the LDST or the BWST to either of the remaining HPI Pumps.

Once the postulated HPI Pump discharge nozzle break is isolated, the other two (2) HPI Pumps and either charging line would be available to support the achieving and maintaining a Safe Shutdown condition and subsequent cooldown to the Cold Shutdown Condition. Likewise, RCP Seal injection could be accomplished from either of the available HPI Pumps. With no other Shutdown Systems or Components targeted, the shutdown of the unit could proceed to a Safe Shutdown condition and to the Cold Shutdown Condition.

The postulated HELBs on the HPI Pump mini-flow lines are Running Breaks with multiple break locations postulated on both mini-flow lines. Each mini-flow piping line has a pair of in-series, restricting orifices that reduce the internal pressure in the mini-flow line to the fluid pressure in the RCP Seal Return piping lines. Any postulated individual HELBs downstream of both of the restricting orifices are excluded because this section of piping does not meet the HE piping definition during Normal Plant Conditions. The remaining postulated HELBs on the mini-flow lines do not target any SSD equipment, but these postulated HELBs would be a potential flooding hazard in the HPI Pump Room.

For a (non-excluded) postulated HELB on either of the HPI Pump mini-flow lines, the detection of this postulated HELB would be very similar to a postulated break at the HPI Pump discharge nozzle. These postulated mini-flow line breaks would cause low HPI header pressure, low RCP Seal Injection flow, and the auto-start of a second HPI Pump. Isolation would be the same as for the HPI Pump discharge nozzle break, and the previously postulated SAF's would be mitigated in the same way. With no other Shutdown Systems or Components targeted, the unit can achieve and maintain the Safe Shutdown condition and could, subsequently, proceed to the Cold Shutdown Condition.

4.2.1.4 <u>HELB Interactions in the Ventilation Equipment Rooms 505 & 602 and Storage (Room) 400B</u>

The only HE piping in Ventilation Equipment Rooms 505 & 602 is the Plant Heating System piping that supplies steam to the Air Handling Units (AHUs). Postulated HELBs on the Plant Heating System in these rooms do not require any protection systems to mitigate the consequences of these breaks.

<u>Ventilation Equipment Room – 505</u>

The HE piping in this room consists of the 24" Main Feedwater System pipe to Steam Generator 1A and the 3" Plant Heating system pipe that supplies steam to the Air Handling Unit 15 (AHU-15). A discussion of each system follows.

The Main Feedwater pipe to Steam Generator 1A passes through this room, but there are no postulated breaks or critical crack locations on this pipe in the room (References 10.2.2).

The PH System HE pipe is routed directly from the Turbine Building into Room 505 to the AHU. There are no direct interactions with the Safe Shutdown pipes (Main Feedwater and Emergency Feedwater) in the Room (References 10.2.2 & 10.2.3). The indirect effects of any postulated PH System HELB in this room cannot adversely affect these pipes because they are passive components. Flooding, compartmental pressurization, or environmental effects could not damage these pipes.

The compartmental pressurization of Room 505 would not cause an adverse condition. The floor and ceiling of the room are reinforced concrete slabs. The walls to this room are unreinforced block or brick walls. The only wall, whose failure could adversely impact any Shutdown Equipment, is the west wall (along Column P). However, a transient analysis performed for Room 520 (Unit 2) shows that the peak pressure created by a postulated PH System HELB (same size 3") will not cause the west wall to fail (References 10.2.50 & 10.2.51). This analysis also applies to Room 505, because of the essentially identical configurations of Room 505 and Room 520 (Reference 10.2.50).

Hence, it can be concluded that for any postulated HELB on the PH System pipe in Room 505 a pathway for achieving and maintaining a Safe Shutdown condition and the subsequent cooldown to the Cold Shutdown Condition exists.

Ventilation Equipment Room - 602

The PH System HE piping that is routed to AHU-9 and AHU-10 in Room 602 is initially routed into the Auxiliary Building Room 507 from the Turbine Building. Room 507 is the Lobby Area just outside of the Control Room. The PH System piping is then routed to Room 508 and up into the Ventilation Equipment Room 602. Any postulated PH System HELB in Room 507 or 508 would not affect the Control Complex, because the doors from the Lobby (Room 507) to the Turbine Building are swinging doors without latches. These doors would open immediately and prevent any compartmental pressurization or flooding in Rooms 507 & 508. Hence, the Control Complex would not be adversely affected by a postulated HELB on the PH System in Rooms 507 or 508. If the postulated HELB were in the Ventilation Equipment Room – 602, electrical equipment inside of the room could be exposed to a steam-air environment. No appreciable pressurization effects are expected due to the relatively low pressure in the PH System and the small line size. In addition, the Ventilation Equipment Room is not an air-tight structure. There are numerous pathways for the steam to be released from the room.

The electrical equipment located inside the room has not been qualified for operation in a steam environment. It is assumed that electrical equipment located in this room would be lost due to environmental effects. The air handling units serving the Unit 1 & 2 Control Room are located in this room. In addition, the outside air booster fans are located inside this room. As a result, all ventilation for the Unit 1 & 2 Control Room is assumed to be lost. The loss of the Control Room Ventilation System does not result in a loss of the habitability of the Main Control Room. However, damage repair procedures would need to be implemented to restore cooling to the Control Room for long term habitability (See Section 3.8.1 of this report).

Storage (Room) 400B

The 24" Main Feedwater pipe to Steam Generator 1B passes through this room, but there are no postulated HELBs or critical crack locations on this pipe in the room (References 10.2.2 & 10.2.3).

4.2.1.5 HELB Interactions in the Station Yard

The only HE piping in the Unit 1 section of the Station Yard is the Unit 1 Main Steam Lines. There are no Shutdown Systems or Components in the Station Yard. Because there is no Shutdown Equipment in the station yard, there are no HELB interactions. The sequence used to shutdown the Unit would be the same as that provided in UFSAR Section 15.13 for a single MSLB.

4.2.2 HELB Interactions in the Turbine Building

Most of the postulated HELBs at the ONS would occur in the Turbine Building. As such, a detailed discussion of the interactions and pathway for achieving and maintaining a Safe Shutdown condition and subsequent cooldown to the Cold Shutdown Condition is provided for all of the HE Systems, except the HPI System. The HE piping associated with the HPI System is not located in the Turbine Building, and no further discussion is required.

4.2.2.1 Auxiliary Steam System

Some of the break locations on the AS System in the Turbine Building were identified as targeting no Shutdown Equipment. For these breaks the pathway for achieving and maintaining a Safe Shutdown condition and subsequent cool down of the Unit to ~250°F RCS temperature would be the normal shutdown sequence using the EFW and HPI Systems. Moreover, the SSF-ASW and PSW Systems could also be used to support the cool down of the Unit to ~250°F RCS temperature condition and maintain ~250°F RCS temperature. After the unit is cooled to ~250°F RCS temperature, the LPI/LPSW Systems would then be used to achieve the Cold Shutdown Condition.

Table 4.2-1 lists the individual breaks and the damage to the station SSD equipment and/or station structures. Most of the individual break locations with identified damage will target some Shutdown Equipment. However, these interactions do not prevent the Unit from proceeding to the Cold Shutdown Condition because only a small number of Shutdown Components were adversely affected by the postulated HELB. The pathway for achieving and maintaining a Safe Shutdown condition and subsequent cooldown to the Cold Shutdown Condition for these breaks would be similar to the methodology described for the non-interacting HELBs above. Some of these postulated HELBs target the LPSW System. For these breaks the pathway for achieving and maintaining a Safe Shutdown condition would be similar to that described for non-interacting postulated breaks, except that once the RCS is cooled down to approximately the 250°F level, an extended period of time may be required to maintain this temperature until the LPSW System is repaired. Once the repairs are made to the LPSW System, the Unit can proceed to the Cold Shutdown Condition.

AS System HELBs can cause ruptures to Duke Class F and/or G Main Steam piping inside the Turbine Building, due to pipe whips. In addition, direct effects to non-safety control systems that impact the TBVs and the MS to SSRHs could lead to blowdown of both SGs. The postulated steam line breaks, as well as the failures in the non-safety control systems for the TBVs and SSRHs would normally be isolated by a single MS branch line isolation valve. However, the power supply and/or controls to these valves may be impacted by the same break. If the capability to close the MS branch line isolation valve from the Control Room is lost, the MSIV could be closed from the Control Room to isolate the break. If local environmental conditions allow access, local manual operation to close the TBVs and the valves on the MS to SSRH lines can be achieved. The functions performed by HPI, EFW, LPI, and LPSW are not impacted by the direct interactions from these postulated breaks in the AS system and are assumed to remain available. The safety consequences on the RCS due to an uncontrolled blow-down of both SGs are addressed in Section 7.1 of the report.

There are a few individual postulated AS System HELBs that would cause multiple interactions with Shutdown Equipment and some could cause an immediate Unit 1 Blackout. The loss of all AC power results in a loss of HPI, EFW, LPI, and LPSW functions. Safe shutdown can be established and maintained using the PSW and HPI (powered from PSW) systems. An alternate means of safe shutdown is the SSF in combination with the MSIVs, but the SSF System alone cannot accommodate a plant cooldown. The PSW and HPI systems would be utilized to cool the unit(s) down to LPI entry conditions. Damage repair procedures (References 10.3.21 – 10.3.25) are utilized to restore power to one CCW pump, one LPI pump, and one LPSW pump. If PSW/HPI is unavailable and the SSF is being used to maintain safe shutdown, damage repair procedures are utilized to restore power to one HPI pump per unit in addition to the CCW, LPSW and LPI pumps prior to initiating a cooldown. As previously discussed, the LPI and LPSW Systems are credited for achieving the Cold Shutdown Condition.

A potential indirect HELB interaction caused by the Auxiliary Steam System is the loss of the Unit 1 Main Feeder Buses and the loss of the EFW and LPSW Pumps, as a result of the steam environment created in the Turbine Building from the postulated HELB. The Main Feeder Bus Switchgear and the EFW and LPSW Pump motors have not been analyzed as being qualified for an elevated temperature, steam-air environment created by a postulated AS System HELB. As such, it is possible that this steam-air environment may eventually, at some time after the initiation of the HELB, cause the failure of this equipment to function. For this postulated HELB scenario, either the PSW or the SSF (in combination with the MSIVs) is credited for achieving and maintaining a Safe Shutdown condition until the Main Feeder Buses, switchgear, and the LPSW System are restored to an operational status. Once the LPSW and LPI Systems are restored to an operational status, the ONS Units could proceed to the Cold Shutdown Condition.

Shutdown equipment located outside the Turbine Building is protected from the effects of postulated AS System HELBs in the Turbine Building. However, if the equipment receives power from electrical sources inside the Turbine Building, the potential exists to lose that power source. None of the postulated AS System HELBs could cause a Turbine Building flood; therefore, damage repair procedures could be implemented as needed when the steam environment has dissipated. None of the postulated HELBs on the AS System cause any collateral damage.

The Turbine Building is a very large and vented volume. Due to its size and openings in the building, there would be no compartmental pressurization in the Turbine Building that would affect the Auxiliary Building. Moreover, the Turbine Building is atmospherically isolated from the Auxiliary Building and the Control Complex. Thus, the environment in the Control Room and the Auxiliary Building is protected from the postulated AS System HELBs. However, as previously discussed (Refer to Section 3.8.1) alternate means of cooling the Control Room may be required for long term occupancy, in the event that the Control Room HVAC System is lost.

The Containment Boundary is unaffected by the postulated AS System HELBs due to the barriers between the postulated HELBs and the Containment Boundary.

4.2.2.2 Condensate System

All of the non-excluded individual break locations on the Condensate System are located in the Turbine Building. Most of these postulated breaks were identified as targeting no Shutdown Equipment. However, it should be noted that these breaks do result in a "Loss of Main Feedwater" event. The RPS is expected to trip the reactor on high RCS pressure and trip the main turbine which closes the main turbine stop valves to prevent overcooling. The pressurizer code safety valves will lift to relieve excess RCS pressure until a source of feedwater can be reestablished to the SG. The EFW System is expected to automatically start following the loss of Main Feedwater, but its operation is impacted by the breaks. The Condensate System line breaks also deplete the condensate inventory stored in the Hotwell. The only condensate inventory credited for the affected unit's EFW is the minimum inventory stored in the UST (30,000 gallons). Some interactions resulting from these postulated HELBs will result in the complete loss of Unit 1 EFW. If the HPI System is available, HPI forced cooling could be utilized to provide decay heat removal until a source of feedwater can be established to the SG(s). Feedwater to the SGs relies upon EFW from an alternate unit (if the cross-connect is available), the new PSW System, or the SSF-ASW System. For these postulated breaks the pathway for achieving and maintaining a Safe Shutdown condition and subsequent cooldown to the Cold Shutdown Condition would be to use the PSW & SSF Systems. The PSW System would be the primary means for achieving a Safe Shutdown condition and cooling down the unit to ~250°F. The SSF-ASW System would serve as a back-up to the PSW System, but the SSF System alone cannot accommodate a plant cooldown. The HPI System is credited for RCS makeup during the plant cooldown. The LPI System is credited for placing the unit in the Cold Shutdown Condition. The LPSW System is credited for supporting the HPI and LPI functions.

Any postulated HELB on the Unit 1 Condensate System with an interaction with Shutdown Equipment is listed in Table 4.2-2. Some of the postulated break locations in the table identify no damage to Shutdown Equipment. The pathway to a Safe Shutdown condition for these breaks would be the same as for the breaks with no targets. The remaining break locations target Shutdown Equipment. However, these interactions do not prevent the unit from proceeding to the Cold Shutdown Condition because only a small number of Shutdown Components were adversely affected by the postulated HELBs. The pathway to a Safe Shutdown condition for these breaks would be similar to the methodology described for breaks with no targets.

Some of the postulated HELBs on the Unit 1 Condensate System can result in Turbine Building flooding. The Condensate System postulated HELBs are, in and of themselves, not the source of Turbine Building flooding due to the limited condensate inventory. However, interactions with CCW and LPSW piping can create a source for Turbine Building flooding. Flood protection measures have been incorporated into the design to protect equipment located inside the Auxiliary Building from flooding inside the Turbine Building, because these postulated HELBs causing flooding inside the Turbine Building can be mitigated with equipment located inside the Auxiliary Building. None of the postulated Condensate System HELBs could cause a Turbine Building flood that could exceed the Auxiliary Building flood barrier height limit of 20 feet (References 10.2.22 & 10.2.33). The PSW System would be credited for achieving and maintaining a Safe Shutdown condition. The SSF in combination with the MSIVs would provide an alternate method for achieving and maintaining a Safe Shutdown condition. The PSW System would be required for plant cooldown.

To achieve the Cold Shutdown Condition the source of the TB flooding would need to be isolated. The CCW Inlet Piping can be isolated by closure of the CCW Pump discharge valves (xCCW-10, xCCW-11, xCCW-12, & xCCW-13) in each unit. A single active failure of any of these valves to close would not result in an unacceptable flood height in the Turbine Building. This is because the flow rate out of the Turbine Building through the Turbine Building Drain will exceed the flooding rate prior to the flood height reaching the 20 foot in the Turbine Building Basement (References 10.2.22 & 10.2.33). If it is not possible to close the failed valve locally, the lake level needs to be lowered to below the 796' Elevation to isolate the inlet flow (References 10.2.36 & 10.2.37). The reverse flow from the CCW discharge piping would be isolated by dropping the CCW Discharge Gates or lowering the lake level below ~ 791' Elevation. Damage repair procedures (References 10.3.21 – 10.3.25) would be utilized to restore CCW and LPSW to an operational status once the TB basement has been drained.

Postulated Condensate System HELBs can result in multiple pipe ruptures in the Duke Class G MS piping connected to the 1B MS lines inside the TB due to pipe whip. In addition, direct effects to non-safety control systems that impact TBVs and MS to SSRHs could lead to blow-down of both SGs. The postulated steam line breaks, as well as the failures in the non-safety control systems for the TBVs and SSRHs would normally be isolated by a single MS branch line isolation valve. However, the power supply and/or controls to these valves may be impacted by the same break. If the capability to close the MS branch line isolation valve from the Control Room is lost, the MSIV could be closed from the Control Room to isolate the break. If local environmental conditions allow access, local manual operation to close the TBVs and the valves on the MS to SSRH lines can be achieved. The functions performed by HPI, EFW, LPI, and LPSW are not impacted by the direct interactions from these postulated breaks in the Condensate System and are assumed to remain available. The safety consequences on the RCS due to an uncontrolled blow-down of both SGs are addressed in Section 7.1 of the report.

Some postulated HELBs on the Condensate System can result in a loss of off-site power. Certain breaks can cause a lockout of the 230kV Switchyard Red and Yellow buses (see Table 4.2-2). The lockout of the 230kV Yellow bus also causes a loss of the emergency overhead path to the startup transformers CT1from the KHU. Emergency power for Unit 1 would be available from the Standby Buses powered by CT4 or CT5.

Postulated Running Break 1-C-090-R would cause multiple interactions with Shutdown Equipment, result in significant flooding in the Turbine Building, and could cause a Unit 1 Blackout. A Safe Shutdown condition can be established and maintained using the PSW and HPI (powered from PSW) Systems. An alternate means of achieving and maintaining a Safe Shutdown condition is the SSF in combination with the MSIVs, but the SSF System alone cannot accommodate a plant cooldown. The PSW and HPI systems would be utilized to cool the unit(s) down to LPI entry conditions. Damage repair procedures are utilized to restore power to one CCW pump, one LPI pump, and one LPSW pump. If PSW/HPI is unavailable and the SSF is being used to maintain a Safe Shutdown condition, damage repair procedures are utilized to restore power to one HPI pump per unit in addition to the CCW, LPSW and LPI pumps prior to initiating a cooldown. The flooding in the Turbine Building is mitigated as described above. As previously discussed, the LPI and LPSW Systems are credited for achieving the Cold Shutdown Condition.

A potential indirect HELB interaction caused by the Condensate System is the loss of the Unit 1 Main Feeder Buses and the loss of the EFW and LPSW Pumps, as a result of the steam environment created in the Turbine Building from the postulated HELB. The Main Feeder Bus Switchgear and the EFW and LPSW Pump motors have not been analyzed as being qualified for an elevated temperature, steam-air environment created by a postulated Condensate System HELB. As such, it is possible that this steam-air environment may eventually, at some time after the initiation of the HELB, cause the failure of this equipment to function. For this postulated HELB scenario, either the PSW System or the SSF (in combination with the MSIVs) is credited for achieving and maintaining a Safe Shutdown condition until the Main Feeder Buses, switchgear, and the LPSW System are restored to an operational status. Once the LPSW and LPI Systems are restored to an operational status, the ONS Units could proceed to the Cold Shutdown Condition.

Shutdown Equipment located outside the Turbine Building is protected from the effects of postulated Condensate System HELBs in the Turbine Building. However, if the equipment receives power from electrical sources inside the Turbine Building, the potential exists to lose that power source. The loss of Control Room Ventilation and its effect on Control Room Habitability is addressed in Section 3.8.1. The potential flooding in the Turbine Building from postulated Condensate System HELBs has been previously discussed.

The Turbine Building is a very large and vented volume. Due to its size and openings in the building, there would be no compartmental pressurization in the Turbine Building that would affect the Auxiliary Building. Moreover, the Turbine Building is atmospherically isolated from the Auxiliary Building and the Control Complex. Thus, the environment in the Control Room and the Auxiliary Building is protected from the postulated Condensate System HELBs. However, as previously discussed (Refer to Section 3.8.1) alternate means of cooling the Control Room may be required for long term occupancy, in the event that the Control Room HVAC System is lost.

The Containment Boundary is unaffected by the postulated Condensate System HELBs due to the barriers between the postulated HELBs and the Containment Boundary.

4.2.2.3 Extraction Steam System

All of the non-excluded individual break locations on the ES System are located in the Turbine Building. Many of these individual breaks were identified as targeting no Shutdown Equipment. For these postulated HELBs, the pathway for achieving and maintaining a Safe Shutdown condition and subsequent cooldown to the Cold Shutdown Condition would be the normal shutdown sequence using the EFW and HPI Systems to achieve a Safe Shutdown condition and cool down the Unit to approximately the 250°F RCS temperature. Moreover, the SSF-ASW and PSW Systems could also be used to support the cool down of the Unit to approximately the 250°F RCS temperature condition and maintain the ~250°F RCS temperature. The LPI/LPSW Systems would then be used to achieve the Cold Shutdown Condition.

Any postulated HELB on the ES System with an interaction with Shutdown Equipment is listed in Table 4.2-3. Several of the break locations in the table identify no damage. The pathway for achieving and maintaining a Safe Shutdown condition and subsequent cooldown to the Cold Shutdown Condition for these breaks would be the same as for the breaks with no targets described in the previous paragraph.

Some of the postulated HELBs, listed on Table 4.2-3, damage multiple Shutdown Components due to pipe whip or jet impingement. The Shutdown Components affected are, in general, the same components for each HELB. Hence, these postulated breaks can be discussed concurrently. These breaks (See Table 4.2-3) result in loss of the MS pressure boundary, 4160 VAC switchgear 1TE, Standby Bus 1, EFW System & its cross connections to the other unit's EFW Systems, and the loss of the "A" Chiller for the Control Complex HVAC System. Even with this equipment not available, a pathway to achieving and maintaining a Safe Shutdown condition can be achieved. The loss of the Standby Bus 1 would be mitigated by using Standby Bus 2 or connecting to startup transformer CT1. The loss of the 1TE Switchgear would result in the loss of HPI Pump 1B, the loss of LPI Pump 1C, and the loss of an LPSW pump. However, there are two (2) other HPI pumps available for achieving and maintaining a Safe Shutdown condition, and there are additional LPI and LPSW Pumps that are not powered from 1TE available to support the cooldown to the Cold Shutdown Condition. Moreover, the HPI Pump 1B could also be powered from the PSW System, if necessary. The Unit 1 EFW and cross connection loss would be mitigated by using the PSW System, which is backed up by the SSF-ASW System. This assures a cooling water supply to the shell side of the SGs. Finally, since no credit is taken for the Control Complex HVAC System (Refer to Section 3.8.1), the loss of the "A" Chiller does not alter the habitability of the Main Control Room. The pathway for achieving and maintaining a Safe Shutdown condition and subsequent cooldown to the Cold Shutdown Condition for these postulated HELBs would be to use one of the (2) HPI Pumps, aligned to the BWST, for reactivity control and RCS inventory control. This HPI Pump along with the pressurizer heaters would be used for RCS level and pressure control. The PSW System or the SSF-ASW System would provide the water for the shell side of the SGs for decay heat removal. This configuration can be used to cool the unit to the LPI/LPSW entry point, and the available LPSW & LPI Pumps would be used to achieve the Cold Shutdown Condition.

ES System HELBs can result in ruptures to Duke Class F and/or G MS piping inside the Turbine Building due to pipe whips. In addition, direct effects to non-safety control systems that impact the TBVs and the MS to SSRHs could lead to blowdown of both SGs. The postulated steam line breaks, as well as the failures in the non-safety control systems for the TBVs and SSRHs would normally be isolated by a single MS branch line isolation valve. However, the power supply and/or controls to these valves may be impacted by the same break. If the capability to close the MS branch line isolation valve from the Control Room is lost, the MSIV could be closed from the Control Room to isolate the break. If local environmental conditions allow access, local manual operation to close the TBVs and the valves on the MS to SSRH lines can also be achieved. The functions performed by HPI, EFW, LPI, and LPSW are not impacted by the direct interactions from these postulated breaks in the AS system and are assumed to remain available. The safety consequences on the RCS due to an uncontrolled blow-down of both SGs are addressed in Section 7.1 of the report.

There are two (2) individual Unit 1 ES System HELBs that can result in a complete loss of 4160VAC power on Unit 1 (See Table 4.2-3). The complete loss of 4160VAC power results in a loss of Unit 1 systems needed for achieving and maintaining a Safe Shutdown condition. The PSW System will provide the primary means of achieving and maintaining a Safe Shutdown condition. The SSF System in combination with the MSIVs would provide an alternate means of achieving and maintaining a Safe Shutdown condition. Plant cooldown can be accomplished using the PSW System. However, in order to cooldown from ~250°F and establish the Cold Shutdown Condition, power would need to be restored to one LPI pump. At least one LPSW pump should remain available as long as 4160VAC power is available on Unit 2.

Postulated HELBs on the ES System can result in Turbine Building flooding. These ES System postulated HELBs are, in and of themselves, not the source of Turbine Building flooding due to the limited condensate inventory. However, interactions with CCW and LPSW piping can create a source for Turbine Building flooding. Flood protection measures have been incorporated into the design to protect equipment located inside the Auxiliary Building from flooding inside the Turbine Building. Most of the postulated ES System HELBs causing flooding inside the Turbine Building can be mitigated with equipment located inside the Auxiliary Building. The maximum flood height inside the Turbine Building is not expected to exceed the protected 20 foot height (References 10.2.22 &10.2.33) for these breaks. However, one of these postulated HELBs (1-ES-020-R-5) can result in a rupture of the 78" diameter CCW water box inlet pipe by collateral damage. A break of this size in the CCW piping could result in a maximum flood height exceeding the 20-foot limit. Operator action is credited to trip the CCW pumps and close the CCW pump discharge valves in accordance with the Turbine Building flooding emergency procedure (Reference 10.3.15). However, additional electrical damage is postulated to result in a loss of power to 1TE Switchgear. This results in a loss of power to one of the CCW pump discharge valves. If any of the CCW valves fail to close, the operators are directed to break the siphon flow on the CCW inlet piping in accordance with the Turbine Building flooding emergency procedure. This action in combination with the isolation of the other three CCW pump discharge lines will prevent the flood height inside the Turbine Building from exceeding 20 foot protected height (References 10.2.22 &10.2.33).

If one of the CCW Pump discharge valves that are not powered from the 1TE Switchgear is the single active failure, the siphon is broken on the failed valve and the non-powered CCW Pump discharge valve is closed manually. This action will prevent the flood height from exceeding the 20 foot elevation. The PSW System would be credited for achieving and maintaining a Safe Shutdown condition. The SSF System in combination with the MSIVs would be credited as the backup method for achieving and maintaining a Safe Shutdown condition. The PSW System would be required for plant cooldown. To achieve the Cold Shutdown Condition the source of the TB flooding would need to be isolated. The CCW Inlet Piping can be isolated by closure of the CCW Pump discharge valves on all units (xCCW-10, xCCW-11, xCCW-12, & xCCW-13). If it is not possible to close all of the CCW Pump discharge valves on all three units, the lake level is lowered to below the 796' Elevation to isolate the inlet flow (References 10.2.36 & 10.2.37). The reverse flow from the CCW discharge piping would be isolated by dropping the CCW Discharge Gates or lowering the lake level below ~ 791' Elevation. Damage repair procedures (References 10.3.21 – 10.3.25) would be utilized to restore CCW and LPSW to an operational status once the TB basement has been drained. Once the LPSW and LPI Systems are restored to an operational status, the ONS Units could proceed to the Cold Shutdown Condition.

A potential indirect HELB interaction caused by the ES System is the loss of the Unit 1 Main Feeder Buses and the loss of the EFW and LPSW Pumps, as a result of the steam environment created in the Turbine Building from the postulated HELB. The Main Feeder Bus Switchgear and the EFW and LPSW Pump motors have not been analyzed as being qualified for an elevated temperature, steam-air environment created by a postulated ES System HELB. As such, it is possible that this steam-air environment may eventually, at some time after the initiation of the HELB, cause the failure of this equipment to function. For this postulated HELB scenario, either the PSW System or the SSF (in combination with the MSIVs) is credited for achieving and maintaining a Safe Shutdown condition until the Main Feeder Buses, switchgear, and the LPSW System are restored to an operational status. Once the LPSW and LPI Systems are restored to an operational status, the ONS Units could proceed to the Cold Shutdown Condition.

Shutdown Equipment located outside the Turbine Building is protected from the effects of postulated ES System HELBs in the Turbine Building. However, if equipment receives power from electrical sources inside the Turbine Building, the potential exists to lose that power source. None of the postulated ES System HELBs could cause a Turbine Building flood; therefore, damage repair procedures could be implemented as needed when the steam environment has dissipated.

The Turbine Building is a very large and vented volume. Due to its size and openings in the building, there would be no compartmental pressurization in the Turbine Building that would affect the Auxiliary Building. Moreover, the Turbine Building is atmospherically isolated from the Auxiliary Building and the Control Complex. Thus, the environment in the Control Room and the Auxiliary Building is protected from the postulated ES System HELBs. However, as previously discussed alternate means of cooling the Control Room may be required for long term occupancy, in the event that the Control Room HVAC System is lost (Refer to Section 3.8.1).

The Containment Boundary is unaffected by the postulated ES System HELBs due to the barriers between the postulated HELBs and the Containment Boundary.

4.2.2.4 Feedwater System

This section describes the consequences of postulated breaks of Main Feedwater piping located in the Turbine Building. A number of breaks were excluded based on normal operating configuration. In addition, a number of Main Feedwater line breaks were found to have no Shutdown Equipment targets within the break zone of influence from pipe whip or jet impingement. However, it should be noted that these breaks result in a loss of Main Feedwater event. The RPS is expected to trip the reactor on high RCS pressure and trip the main turbine which closes the main turbine stop valves to prevent overcooling. The pressurizer code safety valves are credited to relieve excess RCS pressure until a source of feedwater can be reestablished to the SG (Reference 10.2.32). The EFW System is expected to automatically start following the loss of Main Feedwater, but its operation may be impacted by the breaks. The Main Feedwater line breaks also deplete the condensate inventory stored in the Hotwell. The only condensate inventory credited for the affected unit's EFW is the minimum inventory stored in the UST (30,000 gallons), without any additional interactions being considered. Some interactions resulting from FWLBs will result in the complete loss of Unit 1 EFW, as well as the EFW cross-connect piping to other units. If the HPI system is available, HPI forced cooling could be utilized to provide decay heat removal until a source of feedwater can be established to the SG(s). Feedwater to the SGs relies upon EFW from an alternate unit (if the cross-connect is available), the new PSW System, or the SSF-ASW System.

For these postulated breaks the pathway for achieving and maintaining a Safe Shutdown condition and subsequent cooldown to the Cold Shutdown Condition would be to use the PSW & SSF Systems. The PSW System would be the primary means for achieving a Safe Shutdown condition and cooling down the Unit to ~250°F. The SSF System would serve as a back-up to achieving and maintaining a Safe Shutdown condition. The SSF System alone cannot accommodate a plant cooldown. Other equipment would need to be restored using damage repair procedures to accommodate a plant cooldown to ~250°F. This condition would have to be maintained for an extended period of time until the LPSW and LPI Systems are restored to an operational status (References 10.3.21 – 10.3.25) and the Unit could proceed to the Cold Shutdown Condition.

Any postulated HELB on the Unit 1 MFDW System with an interaction with Shutdown Equipment is listed in Table 4.2-4. Some of the postulated break locations in the table identify no damage to Shutdown Equipment. The pathway to a Safe Shutdown condition for these breaks would be the same as for the breaks with no targets. The remaining break locations target Shutdown Equipment. However, these interactions do not prevent the unit from proceeding to the Cold Shutdown Condition because only a small number of Shutdown Components were adversely affected by the postulated HELBs. The pathway to a Safe Shutdown condition for these breaks would be similar to the methodology described for breaks with no targets.

FWLBs may interact with structural components within the Turbine Building resulting in their failure (Ref. Table 4.2-4). Failures of these structure components create collateral damage. The direct effects from pipe whip and jet impingement, as well as the collateral damage created by the structural component failure, have been included in the damage assessment table.

FWLBs can result in ruptures to Duke Class G MS piping inside the Turbine Building due to pipe whips. In addition, direct effects to non-safety control systems that impact TBVs and MS to SSRHs could lead to blow-down of both SGs. Normally, these branch lines would be isolated by the single MS branch line isolation. However, the power supply and /or controls to these valves may be impacted by the same break. If the capability to close the MS branch line isolation valve from the Control Room is lost, the MSIV could be closed from the Control Room to isolate the break. If local environmental conditions allow access, local manual operation to close the TBVs and the valves on the MS to SSRH lines can be achieved. The functions performed by HPI, EFW, LPI, and LPSW are not impacted by the direct interactions from these postulated breaks in the Condensate System and are assumed to remain available. The safety consequences on the RCS due to an uncontrolled blow-down of either or both SGs are addressed in Section 7.1 of this document.

FWLBs can cause a lockout of the 230kV Switchyard Red and Yellow buses (see Table 4.2-4). The lockout of the 230kV Yellow bus also causes a loss of the emergency overhead path to the startup transformer CT1 from the KHU. Emergency power would be available from the standby buses powered by CT4 or CT5.

FWLBs can result in a loss of both Standby Buses (see Table 4.2-4). The loss of both standby buses leaves Unit 1 with the startup transformer, CT1, as the only source of emergency power. This configuration is backed up with the PSW and SSF Systems, if the Startup Transformer CT1 is lost. If Startup Transformer CT1 is lost, the Shutdown Sequence to the Cold Shutdown Condition would be the same as that described for the loss of all AC power case (see net paragraph).

FWLBs can result in a complete loss of 4160VAC power on Unit 1 (see Table 4.2-4). The complete loss of 4160VAC power results in a loss of Unit 1 systems needed for achieving and maintaining a Safe Shutdown condition. The PSW System will provide the primary means for achieving and maintaining a Safe Shutdown condition. The SSF in combination with the MSIVs would provide an alternate means for achieving and maintaining a Safe Shutdown condition. Plant cooldown can be accomplished using the PSW System. However, to establish Cold Shutdown Condition, power would need to be restored to one LPI pump. At least one LPSW pump should remain available as long as 4160VAC power is available on Unit 2. FWLBs can also result in a complete loss of 4160VAC power on Unit 2 (see Table 4.2-4). The additional loss of 4160VAC power on Unit 2 will require power to be restored to one LPSW pump to establish the Cold Shutdown Condition.

FWLBs can result in Turbine Building flooding. The FWLBs, in and of themselves, are not the source of Turbine Building flooding due to the limited condensate inventory. However, interactions with CCW and LPSW piping can create a source for Turbine Building flooding. Flood protection measures have been incorporated into the design to protect equipment located inside the Auxiliary Building from flooding inside the Turbine Building. Most of the FWLBs causing flooding inside the Turbine Building can be mitigated with equipment located inside the Auxiliary Building. The maximum flood height inside the Turbine Building is not expected to exceed the protected 20 foot height for these breaks (References 10.2.22 & 10.2.33). However, one FWLB (1-FDW-031-R-9) can result in a rupture of the 78" diameter CCW water box inlet pipe by collateral damage. A break of this size in the CCW piping could result in a maximum flood height exceeding the 20-foot limit. Operator action is credited to trip the CCW pumps and close the CCW pump discharge valves in accordance with the Turbine Building flooding emergency procedure (Reference 10.3.15). However, additional electrical damage is postulated to result in a loss of power to 1TE Switchgear. This results in a loss of power to one of the CCW pump discharge valves. If any of the CCW valves fail to close, the operators are directed to break the siphon flow on the CCW inlet piping in accordance with the Turbine Building flooding emergency procedure. This action in combination with the isolation of the other three CCW pump discharge lines will prevent the flood height inside the Turbine Building from exceeding 20 foot protected height (References 10.2.22 & 10.2.33).

If one of the CCW Pump discharge valves that are not powered from the 1TE Switchgear is the single active failure, the siphon is broken on the failed valve and the non-powered CCW Pump discharge valve is closed manually. This action will prevent the flood height from exceeding the 20 foot elevation. The PSW System would be credited for achieving and maintaining a Safe Shutdown condition. The SSF System in combination with the MSIVs would be credited as the backup method for achieving and maintaining a Safe Shutdown condition. The PSW System would be required for plant cooldown. To achieve the Cold Shutdown Condition the source of the TB flooding would need to be isolated. The CCW Inlet Piping can be isolated by closure of the CCW

Pump discharge valves on all units (xCCW-10, xCCW-11, xCCW-12, & xCCW-13). If it is not possible to close all of the CCW Pump discharge valves on all three units, the lake level is lowered to below the 796' Elevation to isolate the inlet flow (References 10.2.36 & 10.2.37). The reverse flow from the CCW discharge piping would be isolated by dropping the CCW Discharge Gates or lowering the lake level below ~ 791' Elevation. Damage repair procedures (References 10.3.21 – 10.3.25) would be utilized to restore CCW and LPSW to an operational status once the TB basement has been drained. Once the LPSW and LPI Systems are restored to an operational status, the ONS Units could proceed to the Cold Shutdown Condition.

A potential indirect HELB interaction caused by the MFDW System is the loss of the Unit 1 Main Feeder Buses and the loss of the EFW and LPSW Pumps, as a result of the steam environment created in the Turbine Building from the postulated HELB. The Main Feeder Bus Switchgear and the EFW and LPSW Pump motors have not been analyzed as being qualified for an elevated temperature, steam-air environment created by a postulated MFDW System HELB. As such, it is possible that this steam-air environment may eventually, at some time after the initiation of the HELB, cause the failure of this equipment to function. For this postulated HELB scenario, either the PSW System or the SSF (in combination with the MSIVs) is credited for achieving and maintaining a Safe Shutdown condition until the Main Feeder Buses, switchgear, and the LPSW System are restored to an operational status. Once the LPSW and LPI Systems are restored to an operational status, the ONS Units could proceed to the Cold Shutdown Condition.

Shutdown Equipment located outside the Turbine Building is protected from postulated MFDW System HELBs in the Turbine Building. However, if equipment receives power from electrical sources inside the Turbine Building, the potential exists to lose that power source. The potential flooding in the Turbine Building from postulated MFDW System HELBs has been previously discussed.

The Turbine Building is a very large and vented volume. Due to its size and openings in the building, there would be no compartmental pressurization in the Turbine Building that would affect the Auxiliary Building. Moreover, the Turbine Building is atmospherically isolated from the Auxiliary Building and the Control Complex. Thus, the environment in the Control Room and the Auxiliary Building is protected from the postulated MFDW System HELBs. However, as previously discussed (Refer to Section 3.8.1) alternate means of cooling the Control Room may be required for long term occupancy, in the event that the Control Room HVAC System is lost.

The Containment Boundary is unaffected by the postulated MFDW System HELBs due to the barriers between the postulated HELBs and the Containment Boundary.

4.2.2.5 Heater Drain System

All of the non-excluded individual break locations on the Heater Drain System are located in the Turbine Building. Most of these postulated HELBs were identified as targeting no Shutdown Equipment. For these postulated HELBs the pathway for achieving and maintaining a Safe Shutdown condition and subsequent cooldown to the Cold Shutdown Condition would be the normal shutdown sequence using the EFW and HPI Systems to achieve a Safe Shutdown condition and cool down the Unit to approximately the 250°F RCS temperature. Moreover, the SSF-ASW and PSW Systems could also be used to support the cool down of the Unit to approximately the 250°F RCS temperature condition and maintain the ~250°F RCS temperature. The LPI/LPSW Systems would then be used to achieve the Cold Shutdown Condition.

However, it should be noted that postulated HELBs on the discharge of the 1E or 1D HD Pumps are similar to Condensate System line breaks in that they result in a "Loss of Main Feedwater" event and a loss of condensate inventory stored in the hotwell as described in Section 4.2.2.2. The only condensate inventory credited for the affected unit's EFW is the minimum inventory stored in the UST (30,000 gallons). This limited inventory would not be sufficient for EFW to support a plant cooldown to ~250°F. Feedwater to the SGs relies upon EFW from an alternate unit (if the cross-connect is available), the new PSW System, or the SSF-ASW System. For these postulated breaks the EFW function for enabling a plant cooldown to LPI entry conditions is satisfied by the PSW System or the SSF-ASW System. The PSW System would be the primary means for maintaining a Safe Shutdown condition and cooling down the Unit to ~250°F. The SSF-ASW System would serve as a back-up to PSW System.

Any postulated HELB on the HD System with an interaction with Shutdown Equipment is listed in Table 4.2-5. Several of the postulated break locations on the table identify no damage to Shutdown Equipment. The pathway for achieving and maintaining a Safe Shutdown condition and subsequent cooldown to the Cold Shutdown Condition for these breaks would be the same as for the breaks with no targets.

HD System HELBs can result in ruptures to Duke Class F and/or G MS piping inside the Turbine Building due to pipe whips. In addition, direct effects to non-safety control systems that impact the TBVs and the MS to SSRHs could lead to blowdown of both SGs. Ruptures in the Class G portion or failures in the non-safety control systems for the TBVs and SSRHs would normally be isolated by a single MS branch line isolation valve. However, the power supply and/or controls to these valves may be impacted by the same break. Ruptures in the Class F piping could be isolated by closure of the MSIVs. Ruptures in the Class G piping for Main Steam are normally isolated by the associated Main Steam branch line isolation valve. If the capability to close the MS branch line isolation valve from the Control Room is lost, the MSIV could be closed from the control room to isolate the break. The safety consequences on the RCS due to an uncontrolled blowdown of either or both SGs are addressed in Section 7.1 of this report.

HD System HELBs can also result in a loss of the Unit 1 EFW System. Should circumstances prevent the alignment of the EFW system to an alternate unit, the PSW and SSF-ASW systems provide a redundant means of establishing a source of feedwater to the SG(s).

The postulated Sub-breaks on Running Breaks, 1-HD-031-R and 1-HD-080-R listed in Table 4.2-5, could cause Turbine Building flooding. The Heater Drain System postulated HELBs are, in and of themselves, not the source of Turbine Building flooding due to the limited inventory in the system. However, interactions with CCW and LPSW piping can create a source for Turbine Building flooding. Flood protection measures have been incorporated into the design to protect equipment located inside the Auxiliary Building from flooding inside the Turbine Building, because these postulated HELBs causing flooding inside the Turbine Building can be mitigated with equipment located inside the Auxiliary Building. None of the postulated Heater Drain System HELBs could cause a Turbine Building flood that could exceed the Auxiliary Building flood barrier height limit of 20 feet (References 10.2.22 & 10.2.33). The PSW System would be credited for achieving and maintaining a Safe Shutdown condition. The SSF in combination with the MSIVs would provide an alternate method for achieving and maintaining a Safe Shutdown condition. The PSW System would be required for plant cooldown.

To achieve the Cold Shutdown Condition the source of the TB flooding would need to be isolated. The CCW Inlet Piping can be isolated by closure of the CCW Pump discharge valves (xCCW-10, xCCW-11, xCCW-12, & xCCW-13) in each unit. A single active failure of any of these valves to close would not result in an unacceptable flood height in the Turbine Building. This is because the flow rate out of the Turbine Building through the Turbine Building Drain will exceed the flooding rate prior to the flood height reaching 20 foot in the Turbine Building Basement (References 10.2.22 & 10.2.33). If it is not possible to close the failed valve locally, the lake level needs to be lowered to below the 796' Elevation to isolate the inlet flow (References 10.2.36 & 10.2.37). The reverse flow from the CCW discharge piping would be isolated by dropping the CCW Discharge Gates or lowering the lake level below ~ 791' Elevation. Damage repair procedures (References 10.3.21 – 10.3.25) would be utilized to restore CCW and LPSW to an operational status once the TB basement has been drained. There are no postulated HD System HELBs that result in an immediate Unit blackout.

A potential indirect HELB interaction caused by the Heater Drain System is the loss of the Unit 1 Main Feeder Buses and the loss of the EFW and LPSW Pumps, as a result of the steam environment created in the Turbine Building from the postulated HELB. The Main Feeder Bus Switchgear and the EFW and LPSW Pump motors have not been analyzed as being qualified for an elevated temperature, steam-air environment created by a postulated HD System HELB. As such, it is possible that this steam-air environment may eventually, at some time after the initiation of the HELB, cause the failure of this equipment to function. For this postulated HELB scenario, either the PSW System or the SSF (in combination with the MSIVs) is credited for achieving and maintaining a Safe Shutdown condition until the Main Feeder Buses, switchgear, and the LPSW System are restored to an operational status. Once the LPSW and LPI Systems are restored to an operational status, the ONS Units could proceed to the Cold Shutdown Condition.

Shutdown Equipment located outside the Turbine Building is protected from the effects of postulated HD System HELBs in the Turbine Building. However, if equipment receives power from electrical sources inside the Turbine Building, the potential exists to lose that power source. The potential flooding in the Turbine building from postulated HD System HELBs has been previously discussed.

The Turbine Building is a very large and vented volume. Due to its size and openings in the building, there would be no compartmental pressurization in the Turbine Building that would affect the Auxiliary Building. Moreover, the Turbine Building is atmospherically isolated from the Auxiliary Building and the Control Complex. Thus, the environment in the Control Room and the Auxiliary Building is protected from the postulated HD System HELBs. However, as previously discussed alternate means of cooling the Control Room may be required for long term occupancy, in the event that the Control Room HVAC System is lost (Refer to Section 3.8.1).

The Containment Boundary is unaffected by the postulated HD System HELBs due to the barriers between the postulated HELBs and the Containment Boundary.

4.2.2.6 Heater Vent System

All of the non-excluded Individual Break locations on the Heater Vent System are located in the Turbine Building. All of the postulated HELBs, except for Running Break 1-HV-017-R (See Table 4.2-6), were identified as targeting no Shutdown Equipment. For these postulated HELBs, the pathway for achieving and maintaining a Safe Shutdown condition and subsequent cooldown to the Cold Shutdown Condition would be the normal shutdown sequence using the EFW and HPI Systems to achieve a Safe Shutdown condition and cool down the Unit to approximately the 250°F RCS temperature. Moreover, the SSF-ASW and PSW Systems could also be used to support the EFW function for cool down of the Unit to approximately the 250°F RCS temperature condition and maintain the ~250°F RCS temperature. The LPI/LPSW Systems would then be used to achieve the Cold Shutdown Condition.

Running Break 1-HV-017-R can result in failures to the non-safety control systems that impact the TBVs and the MS to SSRHs leading to the possible blowdown of both SGs. Failures in the non-safety control systems for the TBVs and SSRHs would normally be isolated by a single MS branch line isolation valve. However, the power supply and/or controls to the TBVs may be impacted by the same break. The safety consequences on the RCS due to an uncontrolled blowdown of either or both SGs are addressed in Section 7.1 of this report. The break can also result in a loss of the Unit 1 EFW system. Should circumstances prevent the alignment of the EFW system to an alternate unit, the PSW and SSF-ASW systems provide a redundant means of establishing a source of feedwater to the SG(s).

A potential indirect HELB interaction caused by the Heater Vent System is the loss of the Unit 1 Main Feeder Buses and the loss of the EFW and LPSW Pumps, as a result of the steam environment created in the Turbine Building from the postulated HELB. The Main Feeder Bus Switchgear and the EFW and LPSW Pump motors have not been analyzed as being qualified for an elevated temperature, steam-air environment created by a postulated HV System HELB. As such, it is possible that this steam-air environment may eventually, at some time after the initiation of the HELB, cause the failure of this equipment to function. For this postulated HELB scenario, either the PSW System or the SSF (in combination with the MSIVs) is credited for achieving and maintaining a Safe Shutdown condition until the Main Feeder Buses, switchgear, and the LPSW System are restored to an operational status. Once the LPSW and LPI Systems are restored to an operational status, the ONS Units could proceed to the Cold Shutdown Condition.

The postulated HV System HELBs in the Turbine Building would not affect the Shutdown Equipment in the Auxiliary Building or Control Room Habitability. None of the postulated HV System HELBs could cause a Turbine Building flood. No postulated HELBs on the HV System target any CCW/LPSW System piping, and no HELBs on the HV System cause any collateral damage.

Shutdown Equipment located outside the Turbine Building is protected from the effects of postulated Heater Vent System HELBs in the Turbine Building. However, if the equipment receives power from electrical sources inside the Turbine Building, the potential exists to lose that power source. The loss of Control Room Ventilation and its effect on Control Room Habitability is addressed in Section 3.8.1. The potential flooding in the Turbine Building from postulated Heater Vent System HELBs has been previously discussed.

The Turbine Building is a very large and vented volume. Due to its size and openings in the building, there would be no compartmental pressurization in the Turbine Building that would affect the Auxiliary Building. Moreover, the Turbine Building is atmospherically isolated from the Auxiliary Building and the Control Complex. Thus, the environment in the Control Room and the Auxiliary Building is protected from the postulated HV System HELBs. However, as previously discussed alternate means of cooling the Control Room may be required for long term occupancy, in the event that the Control Room HVAC System is lost (Refer to Section 3.8.1).

The Containment Boundary is unaffected by the postulated HV System HELBs due to the barriers between the postulated HELBs and the Containment Boundary.

4.2.2.7 High Pressure Injection System

There is no High Pressure Injection System HE piping in the Turbine Building.

4.2.2.8 Main Steam System

This section addresses the consequences of postulated ruptures of Main Steam piping located inside the Turbine Building. Any postulated HELB on the Unit 1 MS System in the Turbine Building with an interaction with Shutdown Equipment is listed in Table 4.2-8. The Main Steam piping inside the Turbine Building consists of Duke Class F and Class G piping. Ruptures in the Class F piping could be isolated by closure of the MSIVs. Ruptures in the Class G piping for Main Steam are normally isolated by the associated Main Steam branch line isolation valve. If the capability to close the MS branch line isolation valve from the Control Room is lost, the MSIV could be closed from the Control Room to isolate the break.

Typically, only one Main Steam line is affected by a single postulated break in the Main Steam System. A large break in the Main Steam piping will result in an automatic trip of the reactor from RPS due to low or variable low RCS pressure. Large Main Steam line breaks are described in UFSAR Section 15.13. Small breaks in the Main Steam piping may not result in an automatic trip of the reactor. However, operator action is credited to trip the reactor. Small Main Steam line breaks are described in UFSAR Section 15.17. Once the reactor and main turbine are tripped, the Main Steam lines are separated by the main turbine stop valves.

There is the potential for a single postulated break in the Main Steam System to affect both Main Steam headers even with the closure of the Main Turbine Stop Valves. Normally, both the 1A and 1B MS lines are cross connected through the steam supply to the TDEFW Pump. Breaks in the TDEFW Pump supply lines or postulated breaks that could affect the supply lines could result in a blowdown of both Main Steam lines. However, branch line isolation valves are provided on the MS supply lines to the TDEFW Pump to isolate ruptures in this piping.

One MSLB is postulated to interact with a structural component within the Turbine Building resulting in its failure (Reference - Table 4.2-8 for 1-MS-012). This break is a 12" MS branch line on the 1A MS line to the SSRHs upstream of the MS branch line isolation valve. Failure of this structural component creates collateral damage. The collateral damage created by the structural component failure, has been included in the damage assessment table. The collateral damage can result in a failure of both 36" Main Steam Class F lines causing both SGs to blowdown. In addition, collateral damage can cause a failure of a 30" condensate line which results in a loss of Main Feedwater event. Electrical damage can result in a loss of power to 4160VAC Switchgear 1TE and a loss of all Unit 1 EFW. The loss of power to 1TE results in a loss of one HPI pump, one LPI pump, and one train of control area cooling. The consequences of a double MSLB are discussed in Section 7.1. Two trains of HPI for Engineered Safeguards System operation are not affected by the direct effects of the postulated HELB or by collateral damage. The loss of Main and Emergency Feedwater Systems on Unit 1 would require alignment to an alternate unit's EFW once the overcooling has been terminated. The PSW System or SSF-ASW System could be used to feed the SGs should access to the alternate unit's EFW System be inhibited. The systems necessary for plant cooldown and the establishment of cold shutdown remain available.

Several postulated ruptures in a small diameter MS branch line can impact the electrical distribution system via cable interactions. These cable interactions may result in the loss of all 4160VAC power to Units 1 and 2. In addition, the cable interactions can result in the loss of the TDEFW Pumps on Units 1 and 2, which causes a loss of Main and Emergency Feedwater Systems on both Units 1 and 2. The breaks are identified as 1-MS-077-R-7 and 1-MS-080-R-1 to 6, 8 & 9 (Reference Table 4.2-8). These breaks are 2" and 3", respectively, on the Duke Class G portion of the 1B MS supply to the Condensate Steam Air Ejectors. The loss of power will result in an automatic reactor trip on both Units 1 and 2. Due to the small line size, the severity of the overcooling is expected to be minimal on Unit 1. However, for Running Break 1-MS-080-R additional cable interactions may lead to the TBVs failing open which could result in the simultaneous blowdown of both SGs. Actions would be taken to isolate these branch lines to terminate steam release. If the capability to close any of the MS branch line isolation valves from the Control Room is lost, the MSIV could be closed from the control Room to isolate the break.

The PSW System would be credited for achieving and maintaining Safe Shutdown. An alternate means of safe shutdown is the SSF in combination with the MSIVs. Plant cooldown could be initiated using the PSW System. Damage repairs would need to be completed to proceed to cold shutdown. Power would need to be restored to one LPI pump in each unit. Power would need to be restored to one LPSW pump shared by Units 1 and 2. Once the LPSW and LPI Systems are restored to an operational status, the ONS Units could proceed to the Cold Shutdown Condition.

A number of postulated breaks in the Main Steam System affect AFIS. AFIS is not credited to mitigate Main Steam HELBs inside the Turbine Building.

A potential indirect interaction caused by a MS System HELB is the loss of the Unit 1 Main Feeder Buses and the loss of the EFW and LPSW Pumps, as a result of the steam environment created in the Turbine Building from the postulated HELB. The Main Feeder Bus Switchgear and the EFW and LPSW Pump motors have not been analyzed as being qualified for an elevated temperature, steam-air environment created by a postulated MS System HELB. As such, it is possible that this steam-air environment may eventually, at some time after the initiation of the HELB, cause the failure of this equipment to function. For this postulated HELB scenario, the PSW System or the SSF (in combination with the MSIVs) is credited for achieving and maintaining a Safe Shutdown condition until the Main Feeder Buses, switchgear, and the LPSW System are restored to an operational status. Once the LPSW and LPI Systems are restored to an operational status, the ONS Units could proceed to the Cold Shutdown Condition.

Shutdown Equipment located outside the Turbine Building is protected from the effects of postulated MS System HELBs in the Turbine Building. However, if equipment receives power from electrical sources inside the Turbine Building, the potential exists to lose that power source. None of the postulated MS System HELBs could cause a Turbine Building flood; therefore, damage repair procedures could be implemented as needed when the steam environment has dissipated.

The Turbine Building is a very large and vented volume. Due to its size and openings in the building, there would be no compartmental pressurization in the Turbine Building that would affect the Auxiliary Building. Moreover, the Turbine Building is atmospherically isolated from the Auxiliary Building and the Control Complex. Thus, the environment in the Control Room and the Auxiliary Building is protected from the postulated MS System HELBs. However, as previously discussed (Refer to Section 3.8.1) alternate means of cooling the Control Room may be required for long term occupancy, in the event that the Control Room HVAC System is lost.

The Containment Boundary is unaffected by the postulated MS System HELBs due to the barriers between the postulated HELBs and the Containment Boundary.

4.2.2.9 Moisture Separator Reheater Drain System

All of the non-excluded, Running Breaks, Terminal End breaks, and the Intermediate Breaks on the MSRD System are located in the Turbine Building. Most of these postulated HELBs were identified as targeting no Shutdown Equipment. For these postulated HELBs the pathway for achieving and maintaining a Safe Shutdown condition and subsequent cooldown to the Cold Shutdown Condition would be the normal shutdown sequence using the EFW and HPI Systems to achieve a Safe Shutdown condition and cool down of the Unit to approximately the 250°F RCS temperature. Moreover, the SSF-ASW and PSW Systems could also be used to support the cool down the Unit to approximately the 250°F RCS temperature condition and maintain the ~250°F RCS temperature. The LPI/LPSW Systems would then be used to achieve the Cold Shutdown Condition.

Any postulated HELB on the MSRD System with an interaction with Shutdown Equipment is listed in Table 4.2-9. Several of the break locations in the table identify no damage. The pathway for achieving and maintaining a Safe Shutdown condition and subsequent cooldown to the Cold Shutdown Condition for these breaks would be the same as for the breaks with no targets.

MSRD System HELBs can result in ruptures to Duke Class G MS piping inside the Turbine Building due to pipe whips. In addition, direct effects to non-safety control systems that impact the TBVs and the MS to SSRHs could lead to blowdown of both SGs. Ruptures in the Class G portion or failures in the non-safety control systems for the TBVs and SSRHs would normally be isolated by a single MS branch line isolation valve. However, the power supply and/or controls to these valves may be impacted by the same break. If the capability to close the MS branch line isolation valve from the Control Room is lost, the MSIV could be closed from the Control Room to isolate the break. The safety consequences on the RCS due to an uncontrolled blowdown of either or both SGs are addressed in Section 7.1 of this report.

MSRD System HELBs can also result in a loss of the Unit 1 EFW System. Should circumstances prevent the alignment of the EFW system to an alternate unit, the PSW or the SSF-ASW systems provide a redundant means of establishing a source of feedwater to the SG(s).

Several of the sub-breaks on the MSRD System could cause Turbine Building flooding. Most of the interactions are with small 1 and 1½ inch nominal size LPSW piping. These postulated flooding events would not flood the Turbine Building to a level that could render the EFW and LPSW Pumps unavailable. These pipe ruptures on the LPSW System would be isolated by closing valve 1LPSW-139 (Unit 1 LPSW Non Essential Header Isolation Valve) or 1LPSW-940 (B LPSW Line to TB Non-Essential Header Block Valve). Because of the small size of the broken pipe, the sequence for achieving and maintaining a Safe Shutdown condition would be determined by other interactions for a given postulated HELB.

Two (2) of the postulated sub-breaks on the MSRD System, 1-MSRD-074-R-1 & 2, would target a 14" LPSW piping line. For these postulated HELBs, the broken LPSW pipe could be isolated by closing valve 1LPSW-139. If the broken 14" LPSW pipe is not isolated, Turbine Building flooding would result. Flood protection measures have been incorporated into the design to protect equipment located inside the Auxiliary Building from flooding inside the Turbine Building, because these postulated HELBs causing flooding inside the Turbine Building can be mitigated with equipment located inside the Auxiliary Building. The maximum flood height inside the Turbine Building is not expected to exceed the protected 20 foot height limit for these breaks (References 10.2.22 & 10.2.33). The PSW System would be credited for achieving and maintaining a Safe Shutdown condition. The SSF in combination with the MSIVs would provide an alternate method for achieving and maintaining a Safe Shutdown condition. The PSW System would be required for plant cooldown.

To achieve the Cold Shutdown Condition the source of the TB flooding would need to be isolated. The CCW Inlet Piping can be isolated by closure of the CCW Pump discharge valves (xCCW-10, xCCW-11, xCCW-12, & xCCW-13) in each unit. A single active failure of any of these valves to close would not result in an unacceptable flood height in the Turbine Building. This is because the flow rate out of the Turbine Building through the Turbine Building Drain will exceed the flooding rate prior to the flood height reaching the 20 foot in the Turbine Building Basement (References 10.2.22 & 10.2.33). If it is not possible to close the failed valve locally, the lake level needs to be lowered to below the 796' Elevation to isolate the inlet flow (References 10.2.36 & 10.2.37). The reverse flow from the CCW discharge piping would be isolated by dropping the CCW Discharge Gates or lowering the lake level below ~ 791' Elevation. Damage repair procedures (References 10.3.21 – 10.3.25) would be utilized to restore CCW and LPSW to an operational status once the TB basement has been drained.

A potential indirect HELB interaction caused by the MSRD System is the loss of the Unit 1 Main Feeder Buses and the loss of the EFW and LPSW Pumps, as a result of the steam environment created in the Turbine Building from the postulated HELB. The Main Feeder Bus Switchgear and the EFW and LPSW Pump motors have not been analyzed as being qualified for an elevated temperature, steam-air environment created by a postulated MSRD System HELB. As such, it is possible that this steam-air environment may eventually, at some time after the initiation of the HELB, cause the failure of this equipment to function. For this postulated HELB scenario, either the PSW System or the SSF (in combination with the MSIVs) is credited for achieving and maintaining a Safe Shutdown condition until the Main Feeder Buses, switchgear, and the LPSW System are restored to an operational status. Once the LPSW and LPI Systems are restored to an operational status, the ONS Units could proceed to the Cold Shutdown Condition.

Shutdown Equipment located outside the Turbine Building is protected from the effects of postulated MSRD System HELBs in the Turbine Building. However, if the equipment receives power from electrical sources inside the Turbine Building, the potential exists to lose that power source. The loss of Control Room Ventilation and its effect on Control Room Habitability is addressed in Section 3.8.1. The potential flooding in the Turbine Building from postulated MSRD System HELBs has been previously discussed.

The Turbine Building is a very large and vented volume. Due to its size and openings in the building, there would be no compartmental pressurization in the Turbine Building that would affect the Auxiliary Building. Moreover, the Turbine Building is atmospherically isolated from the Auxiliary Building and the Control Complex. Thus, the environment in the Control Room and the Auxiliary Building is protected from the postulated MSRD System HELBs. However, as previously discussed, alternate means of cooling the Control Room may be required for long term occupancy, in the event that the Control Room HVAC System is lost (Refer to Section 3.8.1).

The Containment Boundary is unaffected by the postulated MSRD System HELBs due to the barriers between the postulated HELBs and the Containment Boundary.

4.2.2.10 Plant Heating System

For the postulated HELBs on the Plant Heating System most of the PH System HE piping is in the Turbine Building. Only eight (8) individual break locations are listed. These postulated breaks do not target Shutdown Equipment. Hence, the pathway to achieving a Safe Shutdown condition and the subsequent cooldown to the Cold Shutdown Condition would be the normal shutdown sequence using the EFW and HPI Systems to achieve a Safe Shutdown condition and cool down the Unit to approximately the 250°F RCS temperature. Moreover, the SSF-ASW and PSW Systems could also be used to support the cool down of the Unit to approximately the 250°F RCS temperature condition and maintain the ~250°F RCS temperature. The LPI/LPSW Systems would then be used to achieve the Cold Shutdown Condition.

A potential indirect HELB interaction caused by the Plant Heating System is the loss of the Unit 1 Main Feeder Buses and the loss of the EFW and LPSW Pumps, as a result of the steam environment created in the Turbine Building from the postulated HELB. The Main Feeder Bus Switchgear and the EFW and LPSW Pump motors have not been analyzed as being qualified for an elevated temperature, steam-air environment created by a postulated PH System HELB. As such, it is possible that this steam-air environment may eventually, at some time after the initiation of the HELB, cause the failure of this equipment to function. For this postulated HELB scenario, either the PSW or the SSF (in combination with the MSIVS) is credited for achieving and maintaining a Safe Shutdown condition until the Main Feeder Buses, switchgear, and the LPSW System are restored to an operational status. Once the LPSW and LPI Systems are restored to an operational status, the ONS Units could proceed to the Cold Shutdown Condition.

The postulated PH System HELBs in the Turbine Building would not affect the Shutdown Equipment in the Auxiliary Building or Control Room Habitability. None of the postulated PH System HELBs could cause a Turbine Building flood. No postulated HELBs on the PH System target any CCW/LPSW System piping, and no HELBs on the PH System cause any collateral damage.

Shutdown Equipment located outside the Turbine Building is protected from the effects of postulated PH System HELBs in the Turbine Building. However, if the equipment receives power from electrical sources inside the Turbine Building, the potential exists to lose that power source. The loss of Control Room Ventilation and its effect on Control Room Habitability is addressed in Section 3.8.1.

The Turbine Building is a very large and vented volume. Due to its size and openings in the building, there would be no compartmental pressurization in the Turbine Building that would affect the Auxiliary Building. Moreover, the Turbine Building is atmospherically isolated from the Auxiliary Building and the Control Complex. Thus, the environment in the Control Room and the Auxiliary Building is protected from the postulated PH System HELBs. However, as previously discussed alternate means of cooling the Control Room may be required for long term occupancy, in the event that the Control Room HVAC System is lost (Refer to Section 3.8.1).

The Containment Boundary is unaffected by the postulated PH System HELBs due to the barriers between the postulated HELBs and the Containment Boundary.

4.2.2.11 Steam Drain System

All of the postulated HELB locations on the Steam Drain System are located in the Turbine Building. The postulated SD System HELBs are on piping connections to the MS System pressure boundary piping or the ES System pressure boundary piping. Most of the postulated HELBs do not interact with any Shutdown Equipment. For the postulated SD System HELBs connected to the MS pressure boundary, the pathway for achieving and maintaining a Safe Shutdown condition and subsequent cooldown to the Cold Shutdown Condition is provided in Section 4.2.2.8 (MS System).

For the postulated SD System HELBs connected to the ES pressure boundary, the pathway for achieving and maintaining a Safe Shutdown condition and subsequent cooldown to the Cold Shutdown Condition would be the normal shutdown sequence using the EFW and HPI Systems to achieve a Safe Shutdown condition and cool down the Unit to approximately the 250°F RCS temperature. Moreover, the SSF-ASW and PSW Systems could also be used to support the cool down of the Unit to approximately the 250°F RCS temperature condition and maintain the ~250°F

RCS temperature. The LPI/LPSW Systems would then be used to achieve the Cold Shutdown Condition.

Any postulated HELB on the Steam Drain System with a possible interaction with Shutdown Equipment is provided in Table 4.2-11. None of these breaks target the CCW/ LPSW Systems, which would result in Turbine Building flooding, and none of these postulated breaks directly target the Unit 1 4160 VAC Power Distribution System, which would cause an immediate loss of the system. The most adverse break results in the possible loss of the Unit 1 EFW System. Should circumstances prevent the alignment of the EFW system to an alternate unit, the PSW and SSF-ASW systems provide a redundant means of establishing a source of feedwater to the SG(s). In addition, direct effects to the non-safety control system for the MS to SSRHs could result in a loss of isolation capability for these pathways from the control room. The safety consequences on the RCS due to an uncontrolled blowdown of either or both SGs are addressed in Section 7.1 of this report.

A potential indirect HELB interaction caused by the Steam Drain System is the loss of the Unit 1 Main Feeder Buses and the loss of the EFW and LPSW Pumps, as a result of the steam environment created in the Turbine Building from the postulated HELB. The Main Feeder Bus Switchgear and the EFW and LPSW Pump motors have not been analyzed as being qualified for an elevated temperature, steam-air environment created by a postulated SD System HELB. As such, it is possible that this steam-air environment may eventually, at some time after the initiation of the HELB, cause the failure of this equipment to function. For this postulated HELB scenario, either the PSW or the SSF (in combination with the MSIVs) is credited for achieving and maintaining a Safe Shutdown condition until the Main Feeder Buses, switchgear, and the LPSW System are restored to an operational status. Once the LPSW and LPI Systems are restored to an operational status, the ONS Units could proceed to the Cold Shutdown Condition.

The postulated SD System HELBs in the Turbine Building would not affect the Shutdown Equipment in the Auxiliary Building or Control Room Habitability. None of the postulated SD System HELBs could cause a Turbine Building flood. No postulated HELBs on the SD System target any CCW/LPSW System piping, and no HELBs on the SD System cause any collateral damage.

Shutdown Equipment located outside the Turbine Building is protected from the effects of postulated Steam Drain System HELBs in the Turbine Building. However, if the equipment receives power from electrical sources inside the Turbine Building, the potential exists to lose that power source. The loss of Control Room Ventilation and its effect on Control Room Habitability is addressed in Section 3.8.1.

The Turbine Building is a very large and vented volume. Due to its size and openings in the building, there would be no compartmental pressurization in the Turbine Building that would affect the Auxiliary Building. Moreover, the Turbine Building is atmospherically isolated from the Auxiliary Building and the Control Complex. Thus, the environment in the Control Room and the Auxiliary Building is protected from the postulated SD System HELBs. However, as previously discussed alternate means of cooling the Control Room may be required for long term occupancy, in the event that the Control Room HVAC System is lost (Refer to Section 3.8.1).

The Containment Boundary is unaffected by the postulated SD System HELBs due to the barriers between the postulated HELBs and the Containment Boundary.

4.2.2.12 Steam Seal Header System

All of the non-excluded individual break locations on the Steam Seal Header System are located in the Turbine Building. None of the non-excluded individual breaks cause adverse interactions with any Shutdown Equipment. The pathway for achieving and maintaining a Safe Shutdown condition and subsequent cooldown to the Cold Shutdown Condition for these postulated HELBs would be the normal shutdown sequence using the EFW and HPI Systems to achieve a Safe Shutdown condition and cool down the Unit to approximately the 250°F RCS temperature. Moreover, the PSW and SSF-ASW Systems could also be used to support the cool down of the Unit to approximately the 250°F RCS temperature condition and maintain the ~250°F RCS temperature. The LPI/LPSW Systems would then be used to achieve the Cold Shutdown Condition.

A potential indirect HELB interaction caused by the Steam Seal Header System is the loss of the Unit 1 Main Feeder Buses and the loss of the EFW and LPSW Pumps, as a result of the steam environment created in the Turbine Building from the postulated HELB. The Main Feeder Bus Switchgear and the EFW and LPSW Pump motors have not been analyzed as being qualified for an elevated temperature, steam-air environment created by a postulated SSH System HELB. As such, it is possible that this steam-air environment may eventually, at some time after the initiation of the HELB, cause the failure of this equipment to function. For this postulated HELB scenario, either the PSW System or the SSF (in combination with the MSIVs) is credited for achieving and maintaining a Safe Shutdown condition until the Main Feeder Buses, switchgear, and the LPSW System are restored to an operational status. Once the LPSW and LPI Systems are restored to an operational status, the ONS Units could proceed to the Cold Shutdown Condition.

The postulated SSH System HELBs in the Turbine Building would not affect the Shutdown Equipment in the Auxiliary Building or Control Room Habitability. None of the postulated SSH System HELBs could cause a Turbine Building flood. No postulated HELBs on the SSH System target any CCW/LPSW System piping, and no HELBs on the SSH System cause any collateral damage.

Shutdown equipment located outside the Turbine Building is protected from the effects of postulated SSH System HELBs in the Turbine Building. However, if the equipment receives power from electrical sources inside the Turbine Building, the potential exists to lose that power source. The loss of Control Room Ventilation and its effect on Control Room Habitability is addressed in Section 3.8.1.

The Turbine Building is a very large and vented volume. Due to its size and openings in the building, there would be no compartmental pressurization in the Turbine Building that would affect the Auxiliary Building. Moreover, the Turbine Building is atmospherically isolated from the Auxiliary Building and the Control Complex. Thus, the environment in the Control Room and the Auxiliary Building is protected from the postulated SSH System HELBs. However, as previously discussed alternate means of cooling the Control Room may be required for long term occupancy, in the event that the Control Room HVAC System is lost (Refer to Section 3.8.1).

The Containment Boundary is unaffected by the postulated SSH System HELBs due to the barriers between the postulated HELBs and the Containment Boundary.

4.3 Unit 1 HELB Interactions with Other Units

The effects of postulated HELBS from the Unit 1 HE lines on the Units 2 & 3 equipment and structures are identified in this section. The information on this section is based upon field inspections of the area of influence of each postulated HELB, and these interactions with Unit 2 and/or Unit 3 equipment are documented in Calculation OSC-7516.02 and evaluated in Calculations OSC-7516.04, OSC-7516.08, and OSC-7516.10 (References 10.2.6, 10.2.8, 10.2.11, & 10.2.13, respectively).

4.3.1 Interactions with Unit 2 Equipment and Structures

For each of the twelve (12) HE systems on Unit 1 the interactions with Unit 2 equipment and the pathway to Safe Shutdown in Unit 2 are described in this section.

4.3.1.1 Auxiliary Steam System

Two (2) of the postulated HELBs on the Unit 1 AS System target cabling that causes a loss of the 230kV Switchyard Red and Yellow buses (see Table 4.2-1). The lockout of the 230kV Yellow bus also causes a loss of the emergency overhead path to the Startup Transformer CT2 from the KHU. Emergency power for Unit 2 would be available from the standby buses powered by CT-4 or CT-5.

Postulated HELBs on the Unit 1 Auxiliary Steam System would release steam to the interior of the Turbine Building. The steam in the Turbine Building may cause loss of the Unit 2 Main Feeder Buses, in addition to the loss of the EFW and LPSW Pumps due to the postulated Auxiliary Steam System HELB. All three (3) ONS Units share a combined Turbine Building, and the Main Feeder Bus, Switchgear, the EFW Pumps, and the LPSW Pumps have not been analyzed as qualified for a steam environment. As such, it is possible that this steam-air environment may eventually, at some time after the initiation of the HELB, cause the failure of this equipment to function. For this interaction the PSW System or the SSF (in combination with the MSIVs) can be utilized to achieve a Safe Shutdown condition and maintain that condition until the Main Feeder Buses and the LPSW System could be restored to an operational status. Once the LPSW and LPI Systems are restored to operability, the ONS Units can proceed to the Cold Shutdown Condition.

4.3.1.2 Condensate System

Several of the postulated HELBs on the Unit 1 Condensate System target cabling that causes a loss of the 230kV Switchyard Red and Yellow buses (see Table 4.2-2). The lockout of the 230kV Yellow bus also causes a loss of the emergency overhead path to the Startup Transformer CT2 from the KHU. Emergency power for Unit 2 would be available from the standby buses powered by CT-4 or CT-5.

Other postulated HELBs cause a loss of the Unit 2 Main Feeder Bus #2 (see Table 4.2-2 for 1-C-090-R-8, 9, & 8L). For this interaction the Unit 2 Main Feeder Bus #1 would be used for that station auxiliary power.

The postulated HELBs on the Unit 1 Condensate System, due to interactions with other systems, can cause significant flooding in the Turbine Building. The flooding can cause a loss of the EFW and LPSW Systems in Unit 2, due to submergence of the EFW and LPSW pumps. Safe Shutdown, following Turbine Building flooding, can be achieved and maintained using the PSW System or the SSF (in combination with the MSIVs) until such time as the flooding can be stopped, the water drained out of the Turbine Building, and restoration of the LPSW System is achieved. Once LPSW has been restored, the plant can be cooled to the Cold Shutdown Condition.

The steam-air environment created inside the Turbine Building from Unit 1 Condensate System breaks may potentially result in a loss of the Unit 2 electrical power distribution system. All three (3) ONS units share a combined Turbine Building. The main feeder buses, the 4160VAC switchgear, the EFW pump motors, and the LPSW pump motors are located inside the Turbine Building. This electrical equipment has not been qualified for a steam-air environment. As such, it is possible that this steam-air environment may eventually, at some time after the initiation of the HELB, cause the failure of this equipment to function. The PSW System or the SSF (in combination with the MSIVs) can be utilized to achieve a Safe Shutdown condition and maintain that condition until the Main Feeder Buses and the LPSW System could be restored to an operational status. Once power can be restored to the LPI and LPSW Systems, the plant can be cooled to the Cold Shutdown Condition.

4.3.1.3 Extraction Steam System

Several of the postulated HELBs on the Unit 1 ES System target cabling for the Unit 2 Standby Buses 1 & 2 and the Main Feeder Bus 2 (see Table 4.2-3). The loss of the standby buses leaves Unit 2 with Main Feeder Bus 1 and with the startup transformer, CT2, as the only source of emergency power. This configuration is backed up with the PSW and SSF Systems, if a failure in switching causes the loss of the Startup Transformer CT2.

The postulated HELBs on the Unit 1 Extraction Steam System, due to interaction with other systems, can cause significant flooding in the Turbine Building. The flooding can cause a loss of the EFW and LPSW Systems in Unit 2, due to submergence of the EFW and LPSW pumps. Safe Shutdown, following Turbine Building flooding, can be achieved and maintained using the PSW System or the SSF (in combination with the MSIVs) until such time as the flooding can be stopped, the water drained out of the Turbine Building, and restoration of the LPSW System is achieved. Once LPSW has been restored, the plant can be cooled to the Cold Shutdown Condition.

The steam-air environment created inside the Turbine Building from Unit 1 Extraction Steam System breaks may potentially result in a loss of the Unit 2 electrical power distribution system. All three (3) ONS units share a combined Turbine Building. The main feeder buses, the 4160VAC switchgear, the EFW pump motors, and the LPSW pump motors are located inside the Turbine Building. This electrical equipment has not been qualified for a steam-air environment. As such, it is possible that this steam-air environment may eventually, at some time after the initiation of the

HELB, cause the failure of this equipment to function. The PSW System or the SSF (in combination with the MSIVs) can be utilized to achieve a Safe Shutdown condition and maintain that condition until the Main Feeder Buses and the LPSW System could be restored to an operational status. Once power can be restored to the LPI and LPSW Systems, the plant can be cooled to the Cold Shutdown Condition.

4.3.1.4 Feedwater System

Postulated HELBs on the Unit 1 MFDW System can cause a lockout of the 230kV Switchyard Red and Yellow buses (See Table 4.2-4). The lockout of the 230kV Yellow bus also causes a loss of the emergency overhead path to the startup transformer CT2 from the KHU. Emergency power for Unit 2 would be available from the standby buses powered by CT-4 or CT-5.

Several of the postulated HELBs (See Table 4.2-4) on the Unit 1 MFDW System target cabling that causes a loss of all 4160 VAC power in Unit 2 and for some of these HELBs a loss of the Unit 2 TDEFW Pump. The complete loss of AC power results in a loss of Unit 2 systems needed for achieving and maintaining the Safe Shutdown condition. The PSW System will provide the primary means of achieving and maintaining a Safe Shutdown condition. The SSF in combination with the MSIVs would provide an alternate means of achieving and maintaining a Safe Shutdown condition. Plant cooldown can be accomplished using the PSW System. However, in order to cooldown from ~250°F and establish the Cold Shutdown Condition, power would need to be restored to one LPI pump and one LPSW pump.

Several of the postulated HELBs on the Unit 1 MFDW System target cabling for the Unit 2 Standby Buses 1 & 2 and the Main Feeder Bus 2 (See Table 4.2-4). The loss of the standby buses leaves Unit 2 with Main Feeder Bus 1 and with the startup transformer, CT2, as the only source of emergency power. This configuration is backed up with the PSW and SSF Systems, if a failure in switching causes the loss of the Startup Transformer CT2.

The postulated HELBs on the Unit 1 Main Feedwater System, due to interaction with other systems, can cause significant flooding in the Turbine Building. The flooding can cause a loss of the EFW and LPSW Systems in Unit 2, due to submergence of the EFW and LPSW pumps. Safe Shutdown, following Turbine Building flooding, can be achieved and maintained using the PSW and/or SSF Systems until such time as the flooding can be stopped, the water drained out of the Turbine Building, and restoration of the LPSW System is achieved. Once LPSW has been restored, the plant can be cooled to the Cold Shutdown Condition.

The steam-air environment created inside the Turbine Building from Unit 1 Main Feedwater System breaks may potentially result in a loss of the Unit 2 electrical power distribution system. All three (3) ONS units share a combined Turbine Building. The main feeder buses, the 4160VAC switchgear, the EFW pump motors, and the LPSW pump motors are located inside the Turbine Building. This electrical equipment has not been qualified for a steam-air environment. As such, it is possible that this steam-air environment may eventually, at some time after the initiation of the HELB, cause the failure of this equipment to function. The PSW System or the SSF (in combination with the MSIVs) can be utilized to achieve a Safe Shutdown condition and maintain that condition until the Main Feeder Buses and the LPSW System could be restored to an operational status. Once power can be restored to the LPI and LPSW Systems, the plant can be cooled to the Cold Shutdown Condition.

4.3.1.5 Heater Drain System

There are no direct interactions between the postulated Unit 1 Heater Drain System HELBs and Unit 2 equipment and structures. Because of the lack of direct interactions no further evaluation of direct interactions is required.

The postulated HELBs on the Unit 1 Heater Drain System, due to interaction with other systems, can cause significant flooding in the Turbine Building. The flooding can cause a loss of the EFW and LPSW Systems in Unit 2, due to submergence of the EFW and LPSW pumps. Safe Shutdown, following Turbine Building flooding, can be achieved and maintained using the PSW System or SSF (in combination with the MSIVs) until such time as the flooding can be stopped, the water drained out of the Turbine Building, and restoration of the LPSW System is achieved. Once LPSW has been restored, the plant can be cooled to the Cold Shutdown Condition.

The steam-air environment created inside the Turbine Building from Unit 1 Heater Drain System breaks may potentially result in a loss of the Unit 2 electrical power distribution system. All three (3) ONS units share a combined Turbine Building. The main feeder buses, the 4160VAC switchgear, the EFW pump motors, and the LPSW pump motors are located inside the Turbine Building. This electrical equipment has not been qualified for a steam-air environment. As such, it is possible that this steam-air environment may eventually, at some time after the initiation of the HELB, cause the failure of this equipment to function. The PSW System or the SSF (in combination with the MSIVs) can be utilized to achieve a Safe Shutdown condition and maintain that condition until the Main Feeder Buses and the LPSW System could be restored to an operational status. Once power can be restored to the LPI and LPSW Systems, the plant can be cooled to the Cold Shutdown Condition.

4.3.1.6 Heater Vent System

There are no direct interactions between the postulated Unit 1 Heater Vent System HELBs and Unit 2 equipment and structures. Because of the lack of direct interactions no further evaluation of direct interactions is required.

The Postulated HELBs on the Unit 1 Heater Vent System would release steam to the interior of the Turbine Building. The steam in the Turbine Building may cause loss of the Unit 2 Main Feeder Buses, in addition to the loss of the EFW and LPSW Pumps. All three (3) ONS Units share a combined Turbine Building, and the Main Feeder Bus, Switchgear, the EFW Pumps, and the LPSW Pumps have not been analyzed as qualified for a steam environment. As such, it is possible that this steam-air environment may eventually, at some time after the initiation of the HELB, cause the failure of this equipment to function. For this interaction the PSW System or the SSF (in combination with the MSIVs) can be utilized to achieve a Safe Shutdown condition and maintain that condition until the Main Feeder Buses and the LPSW System could be restored to an operational status. Once the LPSW and LPI Systems are restored to operability, the ONS Units can proceed to the Cold Shutdown Condition.

4.3.1.7 High Pressure Injection System

There are no direct interactions between the postulated HPI HELBs on Unit 1 and the Unit 2 equipment and structures. Because of the lack of direct interactions no further evaluation of direct interactions is required.

The Unit 1 & Unit 2 HPI Pumps share the same compartment (room). The arrangement of the Unit 1 & 2 HPI Pumps is shown on Reference 10.2.30. A postulated HELB at the discharge nozzle of either the 1A or 1B HPI Pump would produce a flood that could eventually affect the Unit 2 HPI Pumps. However, the flooding in the Unit 1-2 HPI Pump Room from a Unit 1 HPI Pump discharge nozzle HELB would also affect the remaining Unit 1 HPI Pumps. Moreover, any flooding in the Unit 1-2 Pump Room would not adversely affect the Unit 2 HPI Pumps any sooner than the Unit 1 HPI Pumps. The mitigation scenario for assuring availability of the remaining Unit 1 HPI Pumps has been previously documented in Section 4.2.1.3. This same scenario would assure availability of the Unit 2 HPI Pumps. There are no other indirect interactions between the postulated Unit 1 HPI HELBs and critical cracks and the Unit 2 equipment and structures, and no further evaluations are required.

4.3.1.8 Main Steam System

Several of the postulated HELBs (See Table 4.2-8) on the Unit 1MS System target cabling that causes a loss of all 4160 VAC power in Unit 2 and the loss of the Unit 2 TDEFW Pump. The complete loss of all AC power results in a loss of Unit 2 systems needed for achieving and maintaining the Safe Shutdown condition. The PSW System will provide the primary means of achieving and maintaining a Safe Shutdown condition. The SSF in combination with the MSIVs would provide an alternate means of achieving and maintaining a Safe Shutdown condition. Plant cooldown can be accomplished using the PSW System. However, in order to cooldown from ~250°F and establish the Cold Shutdown Condition, power would need to be restored to one LPI pump and one LPSW pump.

The Postulated HELBs on the Unit 1 Main Steam System would release steam to the interior of the Turbine Building. The steam in the Turbine Building may cause loss of the Unit 2 Main Feeder Buses, in addition to the loss of the EFW and LPSW Pumps due to the postulated Main Steam System HELB. All three (3) ONS Units share a combined Turbine Building, and the Main Feeder Bus, Switchgear, the EFW Pumps, and the LPSW Pumps have not been analyzed as qualified for a steam environment. As such, it is possible that this steam-air environment may eventually, at some time after the initiation of the HELB, cause the failure of this equipment to function. For this interaction the PSW System or the SSF (in combination with the MSIVs) can be utilized to achieve a Safe Shutdown condition and maintain that condition until the Main Feeder Buses and the LPSW System could be restored to an operational status. Once the LPSW and LPI Systems are restored to operability, the ONS Units can proceed to the Cold Shutdown Condition.

4.3.1.9 Moisture Separator Reheater Drain System

There are no direct interactions between the postulated Unit 1 Moisture Separator Reheater Drain System HELBs and Unit 2 equipment and structures. Because of the lack of direct interactions no further evaluation of direct interactions is required.

The postulated HELBs on the Unit 1 Moisture Separator Reheater Drain System, due to interactions with other systems, can cause significant flooding in the Turbine Building. The flooding can cause a loss of the EFW and LPSW Systems in Unit 2, due to submergence of the EFW and LPSW pumps. Safe Shutdown, following Turbine Building flooding, can be achieved and maintained using the PSW or the SSF (in combination with the MSIVs) until such time as the flooding can be stopped, the water drained out of the Turbine Building, and restoration of the LPSW System is achieved. Once LPSW has been restored, the plant can be cooled to the Cold Shutdown Condition.

The steam-air environment created inside the Turbine Building from Unit 1 Moisture Separator Reheater Drain System breaks may potentially result in a loss of the Unit 2 electrical power distribution system. All three (3) ONS units share a combined Turbine Building. The main feeder buses, the 4160VAC switchgear, the EFW pump motors, and the LPSW pump motors are located inside the Turbine Building. This electrical equipment has not been qualified for a steam-air environment. As such, it is possible that this steam-air environment may eventually, at some time after the initiation of the HELB, cause the failure of this equipment to function. The PSW System or the SSF (in combination with the MSIVs) can be utilized to achieve a Safe Shutdown condition and maintain that condition until the Main Feeder Buses and the LPSW System could be restored to an operational status. Once power can be restored to the LPI and LPSW Systems, the plant can be cooled to the Cold Shutdown Condition.

4.3.1.10 Plant Heating System

There are no direct interactions between the postulated Unit 1 Plant Heating System HELBs and Unit 2 equipment and structures. Because of the lack of direct interactions no further evaluation of direct interactions is required.

The Postulated HELBs on the Unit 1 Plant Heating System would release steam to the interior of the Turbine Building. The steam in the Turbine Building may cause loss of the Unit 2 Main Feeder Buses, in addition to the loss of the EFW and LPSW Pumps due to the postulated Plant Heating System HELB. All three (3) ONS Units share a combined Turbine Building, and the Main Feeder Bus, Switchgear, the EFW Pumps, and the LPSW Pumps have not been analyzed as qualified for a steam environment. As such, it is possible that this steam-air environment may eventually, at some time after the initiation of the HELB, cause the failure of this equipment to function. For this interaction the PSW or the SSF (in combination with the MSIVs) can be utilized to achieve a Safe Shutdown condition and maintain that condition until the Main Feeder Buses and the LPSW System could be restored to an operational status. Once the LPSW and LPI Systems are restored to operability, the ONS Units can proceed to the Cold Shutdown Condition.

4.3.1.11 Steam Drain System

There are no direct interactions between the postulated Unit 1 Steam Drain System HELBs and Unit 2 equipment and structures. Because of the lack of direct interactions no further evaluation of direct interactions is required.

The Postulated HELBs on the Unit 1 Steam Drain System would release steam to the interior of the Turbine Building. The steam in the Turbine Building may cause loss of the Unit 2 Main Feeder Buses, in addition to the loss of the EFW and LPSW Pumps due to the postulated Steam Drain System HELB. All three (3) ONS Units share a combined Turbine Building, and the Main Feeder Bus, Switchgear, the EFW Pumps, and the LPSW Pumps have not been analyzed as qualified for a steam environment. As such, it is possible that this steam-air environment may eventually, at some time after the initiation of the HELB, cause the failure of this equipment to function. For this interaction the PSW or the SSF (in combination with the MSIVs) can be utilized to achieve a Safe Shutdown condition and maintain that condition until the Main Feeder Buses and the LPSW System could be restored to an operational status. Once the LPSW and LPI Systems are restored to operability, the ONS Units can proceed to the Cold Shutdown Condition.

4.3.1.12 Steam Seal Header System

There are no direct interactions between the postulated Unit 1 Steam Seal Header System HELBs and Unit 2 equipment and structures. Because of the lack of direct interactions no further evaluation of direct interactions is required.

The Postulated HELBs on the Unit 1 Steam Seal Header System would release steam to the interior of the Turbine Building. The steam in the Turbine Building due to a postulated Steam Seal Header System HELB may cause loss of the Unit 2 Main Feeder Buses, the EFW Pump Motors, and LPSW Pump Motors. All three (3) ONS Units share a combined Turbine Building, and the Unit 2 Main Feeder Buses, Switchgear, the EFW Pump Motors, and the LPSW Pump Motors have not been analyzed as qualified for a steam environment. As such, it is possible that this steam-air environment may eventually, at some time after the initiation of the HELB, cause the failure of this equipment to function. For this interaction the PSW System or the SSF (in combination with the MSIVs) can be utilized to achieve a Safe Shutdown condition and maintain that condition until the Main Feeder Buses and the LPSW System could be restored to an operational status. Once the LPSW and LPI Systems are restored to operability, the ONS Units can proceed to the Cold Shutdown Condition.

4.3.2 Interactions with Unit 3 Equipment and Structures

For each of the twelve (12) HE systems on Unit 1 that have interactions with Unit 3 equipment, the pathway to Safe Shutdown of Unit 3 is described in this section.

4.3.2.1 Auxiliary Steam System

Two (2) of the postulated HELBs on the Unit 1 AS System target cabling that causes a loss of the 230kV Switchyard Red and Yellow buses (See Table 4.2-1). The lockout of the 230kV Yellow bus also causes a loss of the emergency overhead path to the Startup Transformer CT3 from the KHU. Emergency power source would be from the standby buses powered by CT-4 or CT-5.

The Postulated HELBs on the Unit 1 Auxiliary Steam System would release steam to the interior of the Turbine Building. The steam in the Turbine Building may cause loss of the Unit 3 Main Feeder Buses, in addition to the loss of the EFW and LPSW Pumps due to the postulated Auxiliary Steam System HELB. All three (3) ONS Units share a combined Turbine Building, and the Main Feeder Bus, Switchgear, the EFW Pumps, and the LPSW Pumps have not been analyzed as qualified for a steam environment. As such, it is possible that this steam-air environment may eventually, at some time after the initiation of the HELB, cause the failure of this equipment to function. For this interaction the PSW or the SSF (in combination with the MSIVs) can be utilized to achieve a Safe Shutdown condition and maintain that condition until the Main Feeder Buses and the LPSW System could be restored to an operational status. Once the LPSW and LPI Systems are restored to operability, the ONS Units can proceed to the Cold Shutdown Condition.

4.3.2.2 Condensate System

Several of the postulated HELBs on the Unit 1 Condensate System target cabling that causes a loss of the 230kV Switchyard Red and Yellow buses (See Table 4.2-2). The lockout of the 230kV Yellow bus also causes a loss of the emergency overhead path to the Startup Transformer CT3 from the KHU. Emergency power source would be from the standby buses powered by CT-4 or CT-5.

The postulated HELBs on the Unit 1 Condensate System, due to interactions with other systems, can cause significant flooding in the Turbine Building. The flooding can cause a loss of the EFW and LPSW Systems in Unit 3, due to submergence of the EFW and LPSW pumps. Safe Shutdown, following Turbine Building flooding, can be achieved and maintained using the PSW or the SSF (in combination with the MSIVs) until such time as the flooding can be stopped, the water drained out of the Turbine Building, and restoration of the LPSW System is achieved. Once LPSW has been restored, the plant can be cooled to the Cold Shutdown Condition.

The steam-air environment created inside the Turbine Building from Unit 1 Condensate System breaks may potentially result in a loss of the Unit 3 electrical power distribution system. All three (3) ONS units share a combined Turbine Building. The main feeder buses, the 4160VAC switchgear, the EFW pump motors, and the LPSW pump motors are located inside the Turbine Building. This electrical equipment has not been qualified for a steam-air environment. As such, it is possible that this steam-air environment may eventually, at some time after the initiation of the HELB, cause the failure of this equipment to function. The PSW or SSF (in combination with the MSIVs) can be utilized to achieve a Safe shutdown condition and maintain that condition until the Main Feeder Buses and the LPSW System could be restored to an operational status. Once power can be restored to the LPI and LPSW Systems, the plant can be cooled to the Cold Shutdown Condition.

4.3.2.3 Extraction Steam System

Several of the postulated HELBs on the Unit 1 ES System target cabling for the Unit 3 Standby Bus 1 (See Table 4.2-3). This interaction renders the Unit 3 Standby Bus 1 unavailable. If this occurs, auxiliary power for Unit 3 would still be available from Standby Bus 2 through Main Feeder Bus 2 or from the Startup Transformer CT3.

The postulated HELBs on the Unit 1 Extraction Steam System, due to interactions with other systems, can cause significant flooding in the Turbine Building. The flooding can cause a loss of the EFW and LPSW Systems in Unit 3, due to submergence of the EFW and LPSW pumps. Safe Shutdown, following Turbine Building flooding, can be achieved and maintained using the PSW and/or SSF (in combination with the MSIVs) until such time as the flooding can be stopped, the water drained out of the Turbine Building, and restoration of the LPSW System is achieved. Once LPSW has been restored, the plant can be cooled to the Cold Shutdown Condition.

The steam-air environment created inside the Turbine Building from Unit 1 Extraction Steam System breaks may potentially result in a loss of the Unit 3 electrical power distribution system. All three (3) ONS units share a combined Turbine Building. The main feeder buses, the 4160VAC switchgear, the EFW pump motors, and the LPSW pump motors are located inside the Turbine Building. This electrical equipment has not been qualified for a steam-air environment. As such, it is possible that this steam-air environment may eventually, at some time after the initiation of the HELB, cause the failure of this equipment to function. The PSW or SSF (in combination with the MSIVs) can be utilized to achieve a Safe Shutdown condition and maintain that condition until the Main Feeder Buses and the LPSW System could be restored to an operational status. Once power can be restored to the LPI and LPSW Systems, the plant can be cooled to the Cold Shutdown Condition.

4.3.2.4 Feedwater System

Postulated HELBs on the MFDW System can cause a lockout of the 230kV Switchyard Red and Yellow buses (See Table 4.2-4). The lockout of the 230kV Yellow bus also causes a loss of the emergency overhead path to the Startup Transformer CT3 from the KHU. Emergency power source would be from the standby buses powered by CT-4 or CT-5.

Postulated HELBs on the Unit 1 MFDW System can result in a loss of both Standby Buses (See Table 4.2-4). The loss of the standby buses leaves Unit 3 with the Startup Transformer CT3 as the only source of emergency power. This configuration is backed up with the PSW and SSF Systems, if a failure in switching causes the loss of the Startup Transformer CT3. If Startup Transformer CT3 is lost, the Shutdown Sequence to the Cold Shutdown Condition would be the same as the loss of all AC power case previously in Section 4.2.2.4 of this report.

Postulated HELBs on the Unit 1 MFDW System, due to interactions with other systems, can result in a loss of off-site power (i.e. a Loss of Startup Transformer CT3 and the loss of Standby Buses 1 & 2; See Table 4.2-4). For these events Unit 3 would have power to its auxiliaries, if the unit continued to operate. Once the unit tripped, it would be in a blackout condition. The PSW System or the SSF (in combination with the MSIVs) would be the primary method for achieving and maintaining a Safe Shutdown condition. The PSW System would be used for the RCS Cooldown to approximately the 250°F level. This condition would be maintained until the Unit 3 LPI and LPSW Systems could be returned to service. Once power can be restored to the LPI and LPSW Systems, the plant can be cooled to the Cold Shutdown Condition.

The postulated HELBs on Unit 1 Main Feedwater System, due to interactions with other systems, can cause significant flooding in the Turbine Building. The flooding can cause a loss of the EFW and LPSW Systems in Unit 3, due to submergence of the EFW and LPSW pumps. Safe Shutdown, following Turbine Building flooding, can be achieved and maintained using the PSW System or the SSF (in combination with the MSIVs) until such time as the flooding can be stopped, the water drained out of the Turbine Building, and restoration of the LPSW System is achieved. Once LPSW has been restored, the plant can be cooled to the Cold Shutdown Condition.

The steam-air environment created inside the Turbine Building from Unit 1 Main Feedwater System breaks may potentially result in a loss of the Unit 3 electrical power distribution system. All three (3) ONS units share a combined Turbine Building. The main feeder buses, the 4160VAC switchgear, the EFW pump motors, and the LPSW pump motors are located inside the Turbine Building. This electrical equipment has not been qualified for a steam-air environment. As such, it is possible that this steam-air environment may eventually, at some time after the initiation of the HELB, cause the failure of this equipment to function. The PSW System or SSF (in combination with the MSIVs) can be utilized to achieve a Safe Shutdown condition and maintain that condition until the Main Feeder Buses and the LPSW System could be restored to an operational status. Once power can be restored to the LPI and LPSW Systems, the plant can be cooled to the Cold Shutdown Condition.

4.3.2.5 Heater Drain System

There are no direct interactions between the postulated Unit 1 Heater Drain System HELBs and Unit 3 equipment and structures. Because of the lack of direct interactions no further evaluation of direct interactions is required.

The postulated HELBs on Unit 1 Heater Drain System, due to interactions with other systems, can cause significant flooding in the Turbine Building. The flooding can cause a loss of the EFW and LPSW Systems in Unit 3, due to submergence of the EFW and LPSW pumps. Safe Shutdown, following Turbine Building flooding, can be achieved and maintained using the PSW System or the SSF (in combination with the MSIVs) until such time as the flooding can be stopped, the water drained out of the Turbine Building, and restoration of the LPSW System is achieved. Once LPSW has been restored, the plant can be cooled to the Cold Shutdown Condition.

The steam-air environment created inside the Turbine Building from Unit 1 Heater Drain System breaks may potentially result in a loss of the Unit 3 electrical power distribution system. All three (3) ONS units share a combined Turbine Building. The main feeder buses, the 4160VAC switchgear, the EFW pump motors, and the LPSW pump motors are located inside the Turbine Building. This electrical equipment has not been qualified for a steam-air environment. As such, it is possible that this steam-air environment may eventually, at some time after the initiation of the HELB, cause the failure of this equipment to function. The PSW System or the SSF (in combination with the MSIVs) can be utilized to achieve a Safe Shutdown condition and maintain that condition until the Main Feeder Buses and the LPSW System could be restored to an operational status. Once power can be restored to the LPI and LPSW Systems, the plant can be cooled to the Cold Shutdown Condition.

4.3.2.6 Heater Vent System

There are no direct interactions between the postulated Unit 1 Heater Vent System HELBs and Unit 3 equipment and structures. Because of the lack of direct interactions no further evaluation of direct interactions is required.

The Postulated HELBs on the Unit 1 Heater Vent System would release steam to the interior of the Turbine Building. The steam in the Turbine Building may cause loss of the Unit 3 Main Feeder Buses, in addition to the loss of the EFW and LPSW Pumps due to the postulated Heater Vent System HELB. All three (3) ONS Units share a combined Turbine Building, and the Main Feeder Bus, Switchgear, the EFW Pumps, and the LPSW Pumps have not been analyzed as qualified for a steam environment. As such, it is possible that this steam-air environment may eventually, at some time after the initiation of the HELB, cause the failure of this equipment to function. For this interaction the PSW or the SSF (in combination with the MSIVs) can be utilized to achieve a Safe Shutdown condition and maintain that condition until the Main Feeder Buses and the LPSW System could be restored to an operational status. Once the LPSW and LPI Systems are restored to operability, the ONS Units can proceed to the Cold Shutdown Condition.

4.3.2.7 High Pressure Injection System

There are no direct or indirect interactions between the postulated HELBs on the Unit 1 HPI System and the Unit 3 equipment and structures. All Unit 3 equipment and structures are separated from the postulated HELBs on the Unit 1 HPI System by barriers. Thus, Unit 3 operations and Shutdown Equipment would not be affected by any postulated Unit 1 HPI HELB, and no further evaluation is required.

4.3.2.8 Main Steam System

There are no direct interactions between the postulated Unit 1 Main Steam System HELBs and Unit 3 equipment and structures. Because of the lack of direct interactions no further evaluation of direct interactions is required.

The Postulated HELBs on the Unit 1 Main Steam System would release steam to the interior of the Turbine Building. The steam in the Turbine Building may cause loss of the Unit 3 Main Feeder Buses, in addition to the loss of the EFW and LPSW Pumps due to the postulated Main Steam System HELB. All three (3) ONS Units share a combined Turbine Building, and the Main Feeder Bus, Switchgear, the EFW Pumps, and the LPSW Pumps have not been analyzed as qualified for a steam environment. As such, it is possible that this steam-air environment may eventually, at some time after the initiation of the HELB, cause the failure of this equipment to function. For this interaction the PSW System or the SSF (in combination with the MSIVs) can be utilized to achieve a Safe Shutdown condition and maintain that condition until the Main Feeder Buses and the LPSW System could be restored to an operational status. Once the LPSW and LPI Systems are restored to operability, the ONS Units can proceed to the Cold Shutdown Condition.

4.3.2.9 Moisture Separator Reheater Drain System

There are no direct interactions between the postulated Unit 1 Moisture Separator Reheater Drain System HELBs and Unit 3 equipment and structures. Because of the lack of direct interactions no further evaluation of direct interactions is required.

The postulated HELBs on the Unit 1 Moisture Separator Reheater Drain System can cause significant flooding in the Turbine Building. The flooding can cause a loss of the EFW and LPSW Systems in Unit 3, due to submergence of the EFW and LPSW pumps. Safe Shutdown, following Turbine Building flooding, can be achieved and maintained using the PSW System or SSF (in combination with the MSIVs) until such time as the flooding can be stopped, the water drained out of the Turbine Building, and restoration of the LPSW System is achieved. Once LPSW has been restored, the plant can be cooled to the Cold Shutdown Condition.

The steam-air environment created inside the Turbine Building from the Unit 1 Moisture Separator Reheater Drain System breaks may potentially result in a loss of the Unit 3 electrical power distribution system. All three (3) ONS units share a combined Turbine Building. The main feeder buses, the 4160VAC switchgear, the EFW pump motors, and the LPSW pump motors are located inside the Turbine Building. This electrical equipment has not been qualified for a steam-air environment. As such, it is possible that this steam-air environment may eventually, at some time after the initiation of the HELB, cause the failure of this equipment to function. The PSW System or the SSF (in combination with the MSIVs) can be utilized to achieve a Safe Shutdown condition and maintain that condition until the Main Feeder Buses and the LPSW System could be restored to an operational status. Once power can be restored to the LPI and LPSW Systems, the plant can be cooled to the Cold Shutdown Condition.

4.3.2.10 Plant Heating System

There are no direct interactions between the postulated Unit 1 Plant Heating System HELBs and Unit 3 equipment and structures. Because of the lack of direct interactions no further evaluation of direct interactions is required.

The Postulated HELBs on the Unit 1 Plant Heating System would release steam to the interior of the Turbine Building. The steam in the Turbine Building may cause loss of the Unit 3 Main Feeder Buses, in addition to the loss of the EFW and LPSW Pumps due to the postulated Plant Heating System HELB. All three (3) ONS Units share a combined Turbine Building, and the Main Feeder Bus, Switchgear, the EFW Pumps, and the LPSW Pumps have not been analyzed as qualified for a steam environment. As such, it is possible that this steam-air environment may eventually, at some time after the initiation of the HELB, cause the failure of this equipment to function. For this interaction the PSW or the SSF (in combination with the MSIVs) can be utilized to achieve a Safe Shutdown condition and maintain that condition until the Main Feeder Buses and the LPSW System could be restored to an operational status. Once the LPSW and LPI Systems are restored to operability, the ONS Units can proceed to the Cold Shutdown Condition.

4.3.2.11 Steam Drain System

There are no direct interactions between the postulated Unit 1 Steam Drain System HELBs and Unit 3 equipment and structures. Because of the lack of direct interactions no further evaluation of direct interactions is required.

The Postulated HELBs on the Unit 1 Steam Drain System would release steam to the interior of the Turbine Building. The steam in the Turbine Building may cause loss of the Unit 3 Main Feeder Buses, in addition to the loss of the EFW and LPSW Pumps due to the postulated Steam Drain System HELB. All three (3) ONS Units share a combined Turbine Building, and the Main Feeder Bus, Switchgear, the EFW Pumps, and the LPSW Pumps have not been analyzed as qualified for a steam environment. As such, it is possible that this steam-air environment may eventually, at some time after the initiation of the HELB, cause the failure of this equipment to function. For this interaction the PSW or the SSF (in combination with the MSIVs) can be utilized to achieve a Safe Shutdown condition and maintain that condition until the Main Feeder Buses and the LPSW System could be restored to an operational status. Once the LPSW and LPI Systems are restored to operability, the ONS Units can proceed to the Cold Shutdown Condition.

4.3.2.12 Steam Seal Header System

There are no direct interactions between the postulated Unit 1 Steam Seal Header System HELBs and Unit 3 equipment and structures. Because of the lack of direct interactions no further evaluation of direct interactions is required.

The Postulated HELBs on the Unit 1 Steam Seal Header System would release steam to the interior of the Turbine Building. The steam in the Turbine Building due to a postulated Steam Seal Header System HELB may cause loss of the Unit 3 Main Feeder Buses, the EFW Pump Motors, and LPSW Pump Motors. All three (3) ONS Units share a combined Turbine Building, and the Unit 3 Main Feeder Buses, Switchgear, the EFW Pump Motors, and the LPSW Pump Motors have not been analyzed as qualified for a steam environment. As such, it is possible that this steam-air environment may eventually, at some time after the initiation of the HELB, cause the failure of this equipment to function. For this interaction the PSW System or the SSF (in combination with the MSIVs) can be utilized to achieve a Safe Shutdown condition and maintain the condition until the Main Feeder Buses and the LPSW System could be restored to an operational status. Once the LPSW and LPI Systems are restored to operability, the ONS Units can proceed to the Cold Shutdown Condition.