TempNo.	PI	Question/Response	Status	Plant/ Co.
27.3	IE02	Question: Should a reactor scram due to high reactor water level, where the feedwater pumps tripped due to the high reactor water level, count as a scram with a loss of normal heat removal Background Information: On April 6, 2001 LaSalle Unit 2 (BWR), during maintenance on a motor driven feedwater pump regulating valve, experienced a reactor automatic reactor scram on high reactor water level. During the recovery, both turbine driven reactor feedwater pumps (TDRFPs) tripped due to high reactor water level. The motor driven reactor feedwater pump was not available due to the maintenance being performed. The reactor operators choose to restore reactor water level through the use of the Reactor Core Isolation Cooling (RCIC) System, due to the fine flow control capability of this system, rather than restore the TDRFPs. Feedwater could have been restored by resetting a TDRFP as soon as the control board high reactor water level alarm cleared. Procedure LGA-001 "RPV Control" (Reactor Pressure Vessel control) requires the unit operator to "Control RPV water level between 11 in. and 59.5 in. using any of the systems listed below: Condensate/feedwater, RCIC, HPCS, LPCS, LPCI, RHR." The following control room response actions, from standard operating procedure LOP-FW-04, "Startup of the TDRFP" are required to reset a TDRFP. No actions are required outside of the control room (and no diagnostic steps are required). Verify the following: TDRFP M/A XFER (Manual/Automatic Controller) station is reset to Minimum No TDRFP trip signals are present Depress TDRFP Turbine RESET pushbutton and observe the following Turbine RESET light Illuminates TDRFP High Pressure and Low Pressure Stop Valves OPEN PUSH M/A increase pushbutton on the Manual/Automatic Controller station Should this be considered a scram with the loss of normal heat removal? Proposed Answer:	1/25 Introduced 2/28 NRC to discuss with resident 4/25 Discussed 5/22 On hold 6/12 Discussed. Related FAQ 30.8 9/26 Discussed 10/31 Discussed 3/17 Entered into appeal process (NEI 99-02 R3 Appendix E) 4/28 – Appeal meeting scheduled for May 12, 2005	LaSalle
28.3	IE02	Question: This event was initiated because a feedwater summer card failed low. The failure caused the feedwater circuitry to sense a lower level than actual. This invalid low level signal caused the Reactor Recirculation pumps to shift to slow speed while also causing the feedwater system to feed the Reactor Pressure Vessel (RPV) until a high level scram (Reactor Vessel Water Level – High, Level 8) was initiated. Within the first three minutes of the transient, the plant had gone from Level 8, which initiated the scram, to Level 2 (Reactor Vessel Water Level – Low Low, Level 2), initiating High Pressure Core Spray (HPCS) and Reactor Core Isolation Cooling (RCIC) injection, and again back to Level 8. The operators had observed the downshift of the Recirculation pumps nearly coincident with the scram, and it was not immediately apparent what had caused the trip due to the rapid sequence of events. As designed, when the reactor water level reached Level 8, the operating turbine driven feed pumps tripped.	3/21 Discussed 4/25 Discussed 5/22 Modified to reflect discussion of 4/25, On Hold 6/12 Discussed. Related FAQ 30.8 3/17 Entered into appeal process (NEI 99-02 R3 Appendix E) 4/28 Appeal meeting scheduled for May 12, 2005	Perry

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		The pump control logic prohibits restart of the feed pumps (both the turbine driven pumps and motor driven feed pump (MFP)) until the Level 8 signal is reset. (On a trip of one or both turbine feed pumps, the MFP would automatically start, except when the trip is due to Level 8.) All three feedwater pumps (both turbine driven pumps and the MFP) were physically available to be started from the control room, once the Level 8 trip was reset. Procedures are in place for the operators to start the MFP or the turbine driven feedwater pumps in this situation. Because the cause of the scram was not immediately apparent to the operators, there was initially some misunderstanding regarding the status of the MFP. (Because the card failure resulted in a sensed low level, the combination of the recirculation pump downshift, the reactor scram, and the initiation of HPCS and RCIC at Level 2 provided several indications to suspect low water level caused the scram.) As a result of the initial indications of a plant problem (the downshift of the recirculation pumps), some operators believed the MFP should have started on the trip of the turbine driven pumps. This was documented in several personnel statements and a narrative log entry. Contributing to this initial misunderstanding was a MFP control power available light bulb that did not illuminate until it was touched. In fact, the MFP had functioned as it was supposed to, and aside from the indication on the control panel, there were no impediments to restarting any of the feedwater pumps from the control room. No attempt was made to manually start the MFP prior to resetting the Level 8 feedwater trip signal. Regardless of the issue with the MFP, however, both turbine driven feed pumps were available once the high reactor water level cleared, and could have been started from the control room without diagnosis or repair. Procedures are in place to accomplish this restart, and operators are trained in the evolution. Since RCIC was already in operation, operators elected to use it as the source of inventory, as provided for in the plant emergency instructions, until plant conditions stabilized. Should this event be counted as a Scram with a Loss of Normal Heat Removal?		
		Response: .		
36.1	IE02	Question: With the unit in RUN mode at 100% power, the control room received indication that a Reactor Pressure Vessel relief valve was open. After taking the steps directed by procedure to attempt to reseat the valve without success, operators scrammed the reactor in response to increasing suppression pool temperature. Following the scram, and in response to procedural direction to limit the reactor cooldown rate to less than 100 degrees per hour, the operators closed the Main Steam Isolation Valves (MSIVs). The operators are trained that closure of the MSIV's to limit cool down rate is expected in order to minimize steam loss through normal downstream balance-of-plant loads (steam jet air ejectors, offgas preheaters, gland seal steam). At the time that the MSIVs were closed, the reactor was at approximately 500 psig. One half hour later, condenser vacuum was too low to open the turbine bypass valves and reactor pressure was approximately 325 psig. Approximately eight hours after the RPV relief valve opened, the RPV relief valve closed with reactor pressure at approximately 50 psig. This information is provided to illustrate the time frame during which the reactor was pressurized and condenser vacuum was low. Although the MSIVs were not reopened during this event, they could have been opened at any time. Procedural guidance is provided for reopening the MSIVs. Had the MSIVs been reopened within approximately 30 minutes of their closure, condenser vacuum was sufficient to allow opening of the turbine bypass valves. If it had been desired to reopen the MSIVs later than that, the condenser would have been brought back on line by following the normal startup procedure for the condenser.	9/25 Introduced and discussed 3/17 Entered into appeal process (NEI 99-02 R3 Appendix E) 4/28 Appeal meeting scheduled for May 12, 2005	Quad Cities

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		As part of the normal startup procedure for the condenser, the control room operator draws vacuum in the condenser by dispatching an operator to the mechanical vacuum pump. The operator starts the mechanical vacuum pump by opening a couple of manual valves and operating a local switch. All other actions, including opening the MSIVs and the turbine bypass valves, are taken by the control room operator in the control room. It normally takes between 45 minutes and one hour to establish vacuum using the mechanical vacuum pump. The reactor feed pumps and feedwater system remained in operation or available for operation throughout the event. The condenser remained intact and available and the MSIVs were available to be opened from the control room throughout the event. The normal heat removal path was always and readily available (i.e., use of the normal heat removal path required only a decision to use it and the following of normal station procedures) during this event. Does this scram constitute a scram with a loss of normal heat removal?		
		Response: No. The normal heat removal path was not lost even though the MSIVs were manually closed to control cooldown rate. There was no leak downstream of the MSIVs, and reopening the MSIVs would not have introduced further complications to the event. The normal heat removal path was purposefully and temporarily isolated to address the cooldown rate, only. Reopening the normal heat removal path was always available at the discretion of the control room operator and would not have involved any diagnosis or repair. Further supporting information: The clarifying notes for this indicator state: "*Loss of normal heat removal path* means the loss of the normal heat removal path as defined above. The determining factor for this indicator is whether or not the normal heat removal path is *available*, not whether the operators choose to use that path or some other path." In this case, the operator did not choose to use the path through the MSIVs, even though the normal heat removal path was available. The clarifying notes for this indicator also state: "*Operator actions or design features to control the reactor cooldown rate or water level*, such as closing the main feedwater valves or closing all MSIVs, are not reported in this indicator as long as the normal heat removal path can be readily recovered from the control room without the need for diagnosis or repair." In this case, the closing of the MSIVs was performed solely to control reactor cooldown rate. It was not performed to isolate a steam leak. There was no diagnosis or repair involved in this event. The MSIVs could have been reopened following normal plant procedures		
36.2	IE02	Question: Should an "Unplanned Scram with a Loss of Normal Heat Removal" be reported for the Peach Bottom Unit 2 (July 22, 2003) reactor scram followed by a high area temperature Group I isolation? <u>Description of Event:</u> At approximately 1345 on 07/22/03, a Main Generator 386B and 386F relay trip resulted in a load reject signal to the main turbine and the main turbine control valves went closed. The Unit 2 reactor received an automatic Reactor Protection System (RPS) scram signal as a result of the main turbine control valves closing. Following the scram signal, all control rods fully inserted and, as expected, Primary Containment Isolation System (PCIS) Group II and III isolations occurred due to low Reactor Pressure Vessel (RPV) level. The Group III isolation includes automatic shutdown of Reactor Building Ventilation. RPV level control was re-established with the Reactor Feed System and the scram signal was reset at approximately 1355 hours. At approximately 1356 hours, the crew received a High Area Temperature alarm for the Main Steam Line area. The elevated temperature was a result of the previously described trip of the Reactor Building ventilation system. At approximately 1358, a PCIS Group I isolation signal occurred due to Steam Tunnel High Temperature resulting in the automatic closure of all Main Steam Isolation Valves (MSIV).Following the MSIV closure, the crew transitioned RPV pressure and level control to the High Pressure Coolant Injection	9/25 Introduced and discussed 3/17 Entered into appeal process (NEI 99-02 R3 Appendix E) 4/28 Appeal meeting scheduled for May 12, 2005	Peach Bottom

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		(HPCI) and Reactor Core Isolation Cooling (RCIC) systems. Following the reset of the PCIS Group II and III isolations at approximately 1408, Reactor Building ventilation was restored. At approximately 1525, the PCIS Group I isolation was reset and the MSIVs were opened. Normal cooldown of the reactor was commenced and both reactor recirculation pumps were restarted. Even though the Group I isolation could have been reset following the Group II/III reset at 1408, the crew decided to pursue other priorities before reopening the MSIVs including: stabilizing RPV level and pressure using HPCI and RCIC; maximizing torus cooling; evaluating RCIC controller oscillations; evaluating a failure of MO-2-02A-53A "A" Recirculation Pump Discharge Valve; and, minimizing CRD flow to facilitate restarting the Reactor Recirculation pumps. **Problem Assessment:** It is recognized that loss of Reactor Building ventilation results in rising temperatures in the Outboard MSIV Room. The rate of this temperature rise and the maximum temperature attained are exacerbated by summertime temperature conditions. When the high temperature isolation occurred, the crew immediately recognized and understood the cause to be the loss of Reactor Building ventilation. The crew then prioritized their activities and utilized existing General Plant (GP) and System Operating (SO) procedures to re-open the MSIVs. Reopening of the MSIVs was: • easily facilitated by restarting Reactor Building ventilation, • completed from the control room using normal operating procedures • without the need of diagnosis or repair Therefore, the MSIV closure does not meet the definition of "Loss of normal heat removal path" provided in NEI 99-02, Rev. 2, page 15, line 37, and it is appropriate not to include this event in the associated performance indicator – Unplanned Scrams with Loss of Normal Heat Removal. <u>Discussion of specific aspects of the event:</u> Was the recognition of the condition from the Control Room? ▪ Yes. Rising temperature in the Outboard MSIV Room is indicated by annunciator in the main control room. Local radiation levels are also available in the control room. During the July 22, 2003 scram, control room operators also recognized that the increase in temperature was not due to a steam leak in the Outboard MSIV Room because the local radiation monitor did not indicate an increase in radiation levels. Initiation of the Group I isolation on a Steam Tunnel High Temperature is indicated by two annunciators in the control room. Does it require diagnosis or was it an alarm? ▪ The event is annunciated in the control room as described previously. Is it a design issue? ▪ Yes. The current Unit 2 design has the Group I isolation temperature elements closer to the Outboard MSIV Room ventilation exhaust as compared to Unit 3. As a result, the baseline temperatures, which input into the Group I isolation signal, are higher on Unit 2 than Unit 3. Are actions virtually certain to be successful? ▪ The actions to reset a Group I isolation are straight forward and the procedural guidance is provided to operate the associated equipment. No diagnosis or troubleshooting is required. Are operator actions proceduralized? ▪ The actions to reset the Group I isolation are delineated in General Plant procedure GP-8.A "PCIS Isolation-Group I." The actions to reopen the MSIVs are contained in System Operating procedures SO 1A.7.A-2 "Main Steam System Recovery Following a Group I Isolation" and Check Off List SO 1A.7.A-2		

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		"Main Steam Lineup After a Group I Isolation." These procedures are performed from the control room. How does Training address operator actions? ▪ The actions necessary for responding to a Group I isolation and subsequent recovery of the Main Steam system are covered in licensed operator training. Are stressful or chaotic conditions during or following an accident expected to be present? • As was demonstrated in the event of July 22, 2003, sufficient time existed to stabilize RPV level and pressure control and methodically progress through the associated procedures to reopen the MSIVs without stressful or chaotic conditions		
		Response: The Peach Bottom Unit 2 July 22, 2003 reactor scram followed by a high area temperature Group I isolation should not be included in the Performance Indicator - "Unplanned Scram with a Loss of Normal Heat Removal." This specific MSIV closure does not meet the definition of "Loss of normal heat removal path" provided in NEI 99-02, Rev. 2, page 15, line 37, in that the main steam system was "easily recovered from the control room without the need for diagnosis or repair. Therefore, it would not be appropriate to include this event in the associated performance indicator – Unplanned Scrams with Loss of Normal Heat Removal.		
36.8	IE02	Question: On August 14, 2003 Ginna Station scrammed due to the wide spread grid disturbance in the Northeast United States. Subsequent to the scram, Main Feedwater Isolation occurred as designed on low Tavg coincident with a reactor trip. However, due to voltage swings from the grid disturbance, instrument variations caused the Advanced Digital Feedwater Control System (ADFCS) to transfer to manual control. This transfer overrode the isolation signal causing the Main Feedwater Regulation Valves (MFRVs) to go to, and remain at, the normal or nominal automatic demand position at the time of the transfer, resulting in an unnecessary feedwater addition. The feedwater addition was terminated when the MFRVs closed on the high-high steam generator level (85%) signal. Operators conservatively closed the MSIVs in accordance with the procedure to mitigate a high water level condition in the Steam Generators. Decay heat was subsequently removed using the Atmospheric Relief Valves (ARVs). Should the scram be counted under the PI "Unplanned Scrams with Loss of Normal Heat Removal?"	1/22 Introduced 3/25 Discussed 6/16 Discussed 3/17 Entered into appeal process (NEI 99-02 R3 Appendix E) 4/28 Appeal meeting scheduled for May 12, 2005	Ginna
		Response: No. Under clarifying notes, page 16, lines 18 - 22, NEI 99-02 states: "Actions or design features to control the reactor cool down rate or water level, such as closing the main feedwater valves or closing all MSIVs, are not reported in this indicator as long as the normal heat removal path can be readily recovered from the control room without the need for diagnosis or repair. However, operator actions to mitigate an off-normal condition or for the safety of personnel or equipment (e.g., closing MSIVs to isolate a steam leak) are reported." In this case, a feedwater isolation signal had automatically closed the main feed regulating valves, effectively mitigating the high level condition. Manually closing the MSIVs was a conservative procedure driven action, which in this case was not by itself necessary to protect personnel or equipment. The main feed regulating valves were capable of being easily opened from the control room, and the MSIVs were capable of being opened from the control room (after local action to bypass and equalize pressure, see FAQ 303). In addition, the cause of the high steam generator level was due to voltage fluctuations on the offsite power grid which resulted in the operators closing the MSIVs. Clarifying notes for this performance indicator exempt scrams resulting in loss of all main feedwater flow , condenser vacuum, or turbine bypass capability caused by loss of offsite power. In this case, offsite power was not lost. However, the disturbances in grid voltage affected the ADFCS system which started a chain of events which ultimately resulted in the closure of the MSIVs.		

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36.9	IE02	Question: During startup activities following a refueling outage in which new monoblock turbine rotors were installed in the LP turbines, reactor power was approximately 10% of rated thermal power, and the main turbine was being started up. Feedwater was being supplied to the steam generators by the turbine driven main feedwater pumps, and the main condensers were in service. During main turbine startup, the turbine began to experience high bearing vibrations before reaching its normal operating speed of 1800 rpm, and was manually tripped. The bearing vibrations increased as the turbine slowed down following the trip. To protect the main turbine, the alarm response procedure for high-high turbine vibration required the operators to manually SCRAM the reactor, isolate steam to the main condensers by closing the main steam isolation valves and to open the condenser vacuum breaker thereby isolating the normal heat removal path to the main condensers. This caused the turbine driven main feedwater pumps to trip. Following the reactor SCRAM, the operators manually started the auxiliary feedwater pumps to supply feedwater to the steam generators. Based on industry operating experience, operators expected main turbine vibrations during this initial startup. Nuclear Engineering provided Operations with recommendations on how to deal with the expected turbine vibration issues that included actions up to and including breaking condenser vacuum. Operations prepared the crews for this turbine startup with several primary actions. First, training on the new rotors, including industry operating experience and technical actions being taken to minimize the possibility of turbine rubs was conducted in the pre-outage Licensed Operator Requalification Training. Second, the Alarm Response Procedures (A-34 and B-34) for turbine vibrations were modified to include procedures to rapidly slow the main turbine to protect it from damage. Under the worst turbine vibration conditions, the procedure required operators to trip the reactor, close MSIVs and break main condenser vacuum. Third, operating crews were provided training in the form of a PowerPoint presentation for required reading which included a description of the turbine modifications, a discussion of the revised Alarm Response Procedures and industry operating experience. Does this SCRAM count against the performance indicator for scrams with loss of normal heat removal? Response: No, this scram does not count against the performance indicator for scrams with loss of normal heat removal. The conditions that resulted in the closure of the MSIVs after the reactor trip were expected for the main turbine startup following rotor replacement. Operator actions for this situation had been incorporated into normal plant procedures.	1/22 Introduced 3/25 Discussed. Question to be rewritten and response provided 4/22 Question and response provided 6/16 Discussed 7/22 Discussed 8/18 Discussed 3/17 Entered into appeal process (NEI 99-02 R3 Appendix E) 4/28 Appeal meeting tentatively scheduled for June 2005	Millstone 2
39.1	IE03	Question: On June 23, 2004, condenser waterbox level and temperature readings on the Unit 1 and 2 main condensers indicated partial blockage of the waterbox intake debris filters. The cause was an influx of gracilaria, which is a marine grass found in the river water that is the circulating water intake supply to the plant. Subsequent backwashes of the debris filters were successful at restoring waterbox level and temperature readings to the normal band, except for the 2B-South waterbox, which is one of four waterboxes of the Unit 2 main condenser. An extended backwash was unsuccessful in restoring its readings back to normal. Debris is removed prior to entering the circulating water intake bay by traveling screens with spray nozzles. The 2B-South debris filter is directly downstream from the 2D traveling screen. Investigation of this event found that the spray nozzles for the 2D traveling screen had more fouling than the other spray nozzles. The 2D traveling screen was able to adequately remove normal debris loading, but was not as effective as the other spray nozzles in removing the debris during the large influx of gracilaria. A decision was made on June 24, 2004 to reduce power to about 53% and isolate the 2B-South waterbox to clean its debris filter. The decision to reduce power within 24 hours was based on several factors, such as reduced condenser efficiency, the potential for additional debris filter clogging, and a reduction in reactor water	8/18 Introduced 9/16 On hold for more information 11/18 Discussed 12/15 Discussed 1/27 Discussed 3/17 Discussed (NRC reviewing previous IE03 FAQs) 4/28 Tentative Approval (NRC to provide response revision)	Brunswick

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		chemistry due to elevated condensate demineralizer resin temperatures. It was also based on input from work management, operations, and the load dispatcher. The 2B-South waterbox was successfully cleaned during the downpower and reactor power was restored to normal operating conditions. This was an anticipated power change in response to expected conditions. Operating experience has shown that the plant is susceptible to large influxes of gracilaria when the salinity level in the river water is elevated. For example, gracilaria problems were correlated with high salinity levels in 2002, which led to high vulnerability conditions. In addition, during another influx of gracilaria, a downpower was required in August, 2001 to clean the 1A-South debris filter. In response to experience over the past 5 years with gracilaria and other intake canal debris, modifications are being implemented at the river water intake diversion structure, which is the first barrier for intake debris, to improve the debris removal capability. In response to the influx of gracilaria, the plant implemented compensatory actions for a "High Vulnerability" condition in the intake canal. These actions include manning the diversion structure round-the-clock for manual debris removal, increasing screen wash pressure, and staging fire hoses at the traveling screens, if needed, to assist in removing debris. During the June 23 event, all four waterboxes on Unit 1 and three of four waterboxes on Unit 2 were managed within normal operating levels. The power change was proceduralized. The plant operating procedure for circulating water directs a power reduction to isolate a waterbox and clean the debris filter if an abnormally high differential pressure exists after debris filter flushing has been completed. The influx of gracilaria was not predictable greater than 72 hours in advance. Although the biology staff has found that high salinity levels in the river water make the conditions for a gracilaria release favorable, it is not possible to predict when an excessive influx will occur. The compensatory actions taken for a high vulnerability condition have usually been effective in preventing debris filter clogging. Should this event be counted as an unplanned power change?		
		Response: No, the event should not be counted as an unplanned power change. The increased accumulation of gracilaria in the river water was anticipated due to operating experience with high salinity levels in the river water, but the timing of the gracilaria release into the intake canal could not be predicted with certainty. In addition, the response to the condenser level and temperature conditions is proceduralized.		
40.2	MS02	Question: As discussed in NEI 99-02 (Revision 2), licensees reduce the likelihood of reactor accidents by maintaining the availability and reliability of mitigating systems – systems that mitigate the effects of initiating events to prevent core damage. The Harris Nuclear Plant (HNP) is actively pursuing measures to reduce mitigating system unavailability, such as those discussed below pertaining to High Head Safety Injection (HHSI) unavailability. At the Harris plant, the Essential Services Chilled Water (ESCW) system is a support system (room cooling) for the HHSI system. The HHSI system consists of three centrifugal, high-head pumps, each housed in its own room. HNP Engineering recently analyzed the effect of a loss of ESCW on HHSI availability by performing a room heatup calculation. This analysis showed that a train of HHSI can be maintained available even without the normal room cooling support system (ESCW) for a period greater than the PRA model success criteria (24 hours) through the use of a substitute cooling source powered by a non class 1E electric power source as allowed for in NEI 99-02, Page 37, Lines 27-35. It is important to note that: 1) a HHSI train utilizing the substitute cooling source will be considered Inoperable, 2) only one HHSI train at a time will utilize a substitute cooling source, and 3) the length of time that HHSI is required following a design basis accident is not specified in the FSAR. Since HHSI will remain available throughout the 24 hour period specified in the PRA model success criteria	10/13 Introduced 12/15 Discussed 1/27 Discussed 3/17 Discussed 4/28 Discussed 4/28 Tentative Approval of negative response (NRC to provide response revision)	Harris

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		with a substitute cooling source, the Harris plant considers it available when calculating the NRC's Safety System Unavailability performance indicator. HNP and the resident inspector are not in agreement with respect to how to interpret the definition of unavailability (Page 23, Line 29). Specifically, in this instance, can a safety system train be considered available if it successfully meets its PRA model success criteria or must it satisfy its design basis requirements (long term cooling) to be considered available?		
		Response: A safety system train may be considered available if it successfully meets its PRA model success criteria. Since HHSI will remain available throughout the 24 hour period specified in the PRA model success criteria with a substitute cooling source, it can be considered available when calculating the NRC's Safety System Unavailability performance indicator.		
40.3	MS04	Question: The Safety System Unavailability Performance Indicator for BWR Residual Heat Removal (RHR) Systems monitors: • the ability of the RHR system to remove heat from the suppression pool so that pool temperatures do not exceed plant design limits, and, • the ability of the RHR system to remove decay heat from the reactor core during a normal unit shutdown (e.g., for refueling or servicing). Perry Technical Specifications require an alternate means of decay heat removal (DHR) to be available when removing an RHR system from service. Technical Specifications do not restrict the options for an alternate decay heat removal system to specific systems or methods. The Bases of Technical Specifications for LCO 3.4.10, RHR Shutdown Cooling System - Shutdown, Required Action A.1 state, "The required cooling capacity of the alternate method should be ensured by verifying (by calculation or demonstration) its capability to maintain or reduce temperature. Alternate methods that can be used include (but are not limited to) the Reactor Water Cleanup System." During the repair of Emergency Service Water (ESW) Pump B, an Off-Normal Instruction with an attachment for "RPV Feed And Bleed With ESW Not Available" was credited as an alternate decay heat removal method for the inoperable RHR system. The referenced procedure takes reactor water from the RHR system shutdown cooling flowpath and directs it to the main generator condenser which acts as the heat sink. The condensate and feedwater systems return the cooled water to the reactor. Reactor temperature is limited to 150 °F for this alternate DHR method. The heat removal capability of this method was demonstrated by calculation before being credited. Does the Perry reactor feed and bleed methodology described above constitute an "NRC approved alternate method of decay heat removal" as referenced in NEI 99-02 above?	10/13 Introduced 12/15 Discussed 1/27 Discussed 3/17 Discussed 4/28 Discussed 4/28 Tentative Approval of negative response (NRC to provide response revision)	Perry
		Response: NEI 99-02, "Systems Required to be in Service at All Times" states, "For RHR systems, when the reactor is shutdown with fuel in the vessel, those systems or portions of systems that provide shutdown cooling can be removed from service without incurring planned or unplanned unavailable hours under the following conditions: • RHR trains may be removed from service provided an ***NRC approved alternate method*** of decay heat removal is verified to be available for each RHR train removed from service. The intent is that at all times there will be two methods of decay heat removal available, at least one of which is a forced means of heat removal". ***(Emphasis added.)*** The response to FAQ ID-145 for PI MS04 Residual Heat Removal System Unavailability (Posted 04/01/2000) parenthetically defines an NRC approved method as "an alternate method allowed by Technical Specifications."		

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		Since the Bases of Technical Specification only require that the system be capable of maintaining or reducing temperature and since they do not limit the options to the Reactor Water Cleanup System, the feed and bleed methodology is acceptable as an alternate method of decay heat removal. Thus, the reactor feed and bleed alternate decay heat removal method described above is an NRC approved alternate method.		
40.4	MS03	Question: At 1730 on September 10, 2004, BVPS Unit 1 experienced an automatic start of the turbine driven auxiliary feedwater (TDAFW) pump due to the failure (open position) of the turbine steam supply "B" train trip valve. The steam supply configuration is a single steam supply line with a motor operated valve (MOV) that branches into two parallel supply lines, each of which contains a trip valve. The MOV is normally open and the opening of either trip valve will result in a start of the TDAFW pump. The crew attempted unsuccessfully to close the "B" trip valve from the control room. At 1732, the MOV was shut and direction given to the control room operator in the form of written instructions to open the MOV if the TDAFW pump was required for feeding the steam generators. The written instructions were provided on a Maintenance Rule Availability Restoration Procedure form that is approved by a Senior Reactor Operator. The TDAFW pump was declared Tech Spec inoperable, but maintained available because it could be promptly restored from the control room (i.e. open the MOV) by a qualified operator without diagnosis or repair, consistent with the guidance in NEI 99-02, Revision 2. It was subsequently determined that the cause of the "B" valve opening was a failure of a card in the Solid State Protection System which only affected the "B" train valve. In this scenario, can credit be taken for manual operation action to maintain the TDAFW pump available? Response: Yes. On page 31, Additional Fault Exposure Considerations, NEI 99-02 Revision 2 states that "operator actions to recover from an equipment malfunction or an operating error can be credited if the function can be promptly restored from the control room by a qualified operator taking an uncomplicated action (a single action or a few simple actions) without diagnosis or repair (i.e. the restoration actions are virtually certain to be successful during accident conditions)".	11/18 Introduced 12/15 Discussed 1/27 Discussed 3/17 Discussed (Have licensee participate in next meeting) 4/28 Discussed 4/28 Tentative Approval (NRC to provide response revision) 4/28 NRC action to consider guidance revision and propose as appropriate	Beaver Valley
40.8	MS03	Question: NEI 99-02, pg 33 states that fault exposure is not taken for failures due to a design deficiency that was not capable of being discovered during normal surveillance tests and that these failures are amenable to evaluation through the NRC Significance Determination Process. If a failure occurs due to a combination of historical procedural and physical design deficiencies, should the unavailable hours be counted as fault exposure hours? A Unit 1 condensate storage tank (CST) low-level instrumentation surveillance test (ST) was in progress, which transfers suction from the CST to the Suppression Pool (SP), with the high-pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) systems in the standby mode. During the suction path swap-over, a hydraulic transient occurred which caused an unexpected RCIC low pump suction pressure turbine trip. RCIC was declared inoperable and unavailable. No HPCI alarms or trips were observed. The cause of the RCIC failure was voids in the suction piping for both of the RCIC and HPCI systems due to a combination of physical and procedural design deficiencies. A portion of the RCIC pump suction piping and the HPCI SP suction check valve bonnet were not designed with a vent path and the HPCI fill and vent procedure did not make use of a vent on SP suction piping between the HPCI SP suction check valve and the HPCI outboard isolation suction valve. The presence of air voids in the system could not have been identified during previous surveillance testing or discovered by other mechanisms. The air voids and the design and procedural deficiencies were not identified until troubleshooting and evaluation of the event. The potential for air voids to go unvented had existed since the Unit 1 initial plant startup in 1986. The CST low-level ST in progress at the time of the event involved HPCI components with no testing criteria that would have identified a RCIC problem. This ST had been	11/18 Introduced 1/27 Discussed. Response to be revised by NRC. 2/17 DJW Response revision. 3/17 Discussed (Industry to propose revision to response that references applicable guidance) 4/28 Proposed response revision 4/28 Tentative Approval	Limerick

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		performed on several occasions with no RCIC system transients or alarms. In addition, numerous HPCI and RCIC system pump valve and flow tests and system functional tests had been performed with no indication of voids or hydraulic perturbations that would have identified the design deficiency. This was the first time that conditions were aligned such that the transient could occur. The trigger for the event was a pressure wave developed in the common HPCI/RCIC suction piping during HPCI valve stroking with sufficient magnitude to meet the RCIC low suction pressure trip point. Had the HPCI procedure fully utilized all available HPCI system vent paths or had the HPCI and RCIC system valves and piping been provided with physical vents and procedural guidance in the design, then the transient would not have occurred. The NRC representative believes that the cause of the event included deficiencies beyond design deficiencies that exclude it from consideration as a design failure and therefore should be counted in the PI. The station disagrees with this interpretation and believes that the issue is being adequately assessed through SDP that all design deficiencies ultimately have a human error component, and that FAQs 316 and 348 support this position.		
		Response: Yes, fault exposure hours should be taken. The written guidance in NEI 99-02 allows fault exposure hours to be excluded for design or construction deficiencies leading to failures that are not capable of being discovered during normal surveillance testing. While the guidance is silent on combinations of design and other deficiencies, in this situation, procedural inadequacies were a significant contributor to the inadequate system fill. Additionally, the guidance states that failures capable of being discovered during normal surveillance testing should be evaluated for inclusion. The RCIC system was discovered to be unavailable during the first performance of a routine surveillance test (on the HPCI system) following the inadequate system fill.		
50.1	MS01	Question: (APPENDIX D) The Oconee Nuclear Station emergency power is provided by the Keowee Hydro units (KHUs) located within the Oconee Owner Controlled Area. The Keowee hydroelectric station has been in service since 1971, with the last major overhaul performed in 1985. Duke Energy (Duke) is performing significant upgrades and overhaul maintenance to each KHU to ensure future reliability. This work includes replacement of the governor, exciters, and batteries, and weld repair on the turbine blades and discharge ring along with draft tube concrete repair. This FAQ seeks an exemption from counting the planned overhaul maintenance hours for the one-time KHU outages. *Was there NRC approval through an NOED, Technical Specification change, or other means?* An amendment was approved by the NRC to temporarily extend Technical Specification (TS) 3.8.1 Required Action Completion Times to allow significant maintenance and upgrades to be performed. Even though each KHU is being upgraded one at a time, the tasks of isolating and un-isolating the unit being upgraded makes both KHUs inoperable. The approval allows Duke to temporarily extend the 60 hour Completion Time for restoring one Keowee Hydro Unit (KHU) when both are inoperable by 120 cumulative hours over two dual KHU outages. For example, 60 hour + 40 and 60 hours + 80 for a total of 240 hours is allowed during each KHU (KHU1 & KHU2) Refurbishment Outage. KHU 1 has already completed its extended outage using 206 of the 240 allowed hours in the dual KHU outage. The KHU 2 will be performed in January - February 2005 and is expected to use a similar number of hours spread over two dual KHU outages. Even though one KHU is being upgraded at a time, the tasks of isolating and un-isolating the unit being upgraded makes both KHUs inoperable. During the time period when both KHUs are inoperable, both TS 3.8.1 Required Actions C.2.2.5 and H.2 will be entered. Entry into H.2 is relevant to the underground. Only the underground unavailable hours are reported for PI. *Was there a quantitative risk-assessment of the overhaul activity?* A quantitative risk analysis was performed. The analysis showed that the planned configuration was acceptable per Regulatory Guide 1.177 and 1.174. The cumulative core damage probability (CCDP) for each extended	12/15 Introduced 3/17 Discussed (Have licensee available for next meeting) 4/28 Discussed	Oconee

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		KHU outage was calculated to be 4.4E-07. A subset of the extended single unit outage is the two dual KHU outages (which makes the underground path unavailable for the period of time mentioned above.) *What is the expected improvement in plant performance as a result of the overhaul and what is the net change in risk as a result of the overhaul activity?* The net change in risk as a result of the overhaul activity is reduced because of the expected decrease in future Emergency Power unavailability as a result of the overhaul, and the contingency measures to be utilized during the overhaul. During Duke's December 16, 2003, meeting with NRC, the Staff indicated that even though the revised cumulative CDP was in the E-07 range, their guidelines required defense-in-depth measures to be considered in order to approve the LAR. Duke presented defense-in-depth measures credited to offset the additional risks associated with the dual KHU outages during that meeting and in a December 18, 2003 letter. These defense-in-depth measures, which address grid-related events, switchyard-centered events, and weather-related events, are as follows: For grid-related events • A 100 kV dedicated line separated from the grid • A Lee Combustion Turbine (LCT) already running and energizing the standby buses via the 100 kV dedicated line • Two additional LCTs available, either of which can provide the necessary power • One of the two additional LCTs running and available to be connected to the 100 kV dedicated line during the dual KHU outage • A Jocassee Hydro Unit capable of providing power via a dedicated line separated from the grid • Up to three additional Jocassee hydro units, any of which can provide necessary power and be connected to the dedicated line • Standby Shutdown Facility (SSF) remains available as an alternate shutdown method the SSF will be removed from service for its scheduled monthly maintenance, but not during the dual unit outage For switchyard centered events • 100 kV line not connected to switchyard • Power from Jocassee can be recovered quickly • SSF remains available as an alternate shutdown method For weather-related events that take out switchyard or power lines coming into switchyard - from a qualitative standpoint: • Power lines come in from different directions so it is not likely that Oconee would lose power from all the lines at the same time • The likelihood of having a weather event that takes out all power lines is low • SSF remains available as an alternate shutdown method For this one-time plant specific situation, can the planned overhaul hours for the emergency power support system be excluded from the computation of monitored system unavailability? Response: Yes, the requirements of Appendix D of NEI 99-02 have been met..		
50.2	MS04	Question: This FAQ seeks approval to exclude the unavailability that will be incurred during planned maintenance of large check valves and electric motor operated gate and globe valves in the Low Pressure Injection (LPI) System. This work has traditionally been performed during refueling outages either when a train can be taken out of service without incurring unavailability or during defueled maintenance when neither train of LPI is required to be operable. With a goal of performing shorter outages, it is desired to perform this work during power operation shortly before the start of a refueling outage. Performing this work shortly before the refueling	12/15 Introduced 3/17 Discussed (Have licensee available for next meeting) 4/28 Discussed 4/28 Tentative Approval of negative response (NRC to provide response revision)	Oconee

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		outage will ensure the equipment is operating properly prior to its use for normal decay heat removal. This schedule is also expected to have a significant savings on dose and contamination. Performing this maintenance immediately after the system has been used to cool the unit down results in a maximum level of contamination in this equipment (with Co-58 being a significant contributor). If this work is performed shortly before refueling, there will be approximately 18 months of decay before work is performed (Co-58 will be reduced by a factor of about 190). Although overhaul exemption is allowed for "major" components and components such as pumps and heat exchangers are explicitly classified as being "major" components, there is no discussion of whether certain types of valves can be considered "major" components. While "valves" are often thought of as relatively simple components (and in many instances are), there are numerous valves that are fairly complex due to size, tight shutoff requirements, actuator setup, etc. It seems that these "more complex" valves could be classified as "major" components such that work involving a major overhaul of just these components could be classified as overhaul maintenance. QUANTITATIVE RISK ASSESSMENT, EXPECTED IMPROVEMENT IN PLANT PERFORMANCE, AND NET CHANGE IN RISK AS A RESULT OF THE OVERHAUL ACTIVITY Was there NRC approval through an NOED, Technical Specification change, or other means? In anticipation of moving the maintenance from outage work to "innage" work, Oconee applied for, and has been granted, approved Tech Specs to extend the allowed outage time for a train of LPI from 3 days to 7 days. Was there a quantitative risk-assessment of the overhaul activity? The submittal for this revision was based on the NRC's Safety Evaluation of BWOG Topical Report BAW-2295, Revision 1, "Justification for the Extension of Allowed Outage Time for Low Pressure Injection and Reactor building Spray Systems", (TAC No. MA3807), dated 6/30/99. The BWOG Topical Report contained a quantitative risk assessment. Regulatory Guides (RG) 1.174 and RG 1.177 were used to assess the impact of the proposed change. What is the expected improvement in plant performance, and net change in risk as a result of the extended outage time? The calculated value of incremental conditional core damage probability (ICCDP) for the proposed change was 3.4E-07. The calculated value of incremental conditional large early release probability (ICLERP) for the proposed change was 4.4E-10. These values are considered small for a single TS Completion Time change when compared against the 5.0E-07 and 5.0E-08 RG 1.177 guideline values. The NRC SER found the ICCDP values acceptable due to the following compensatory measures that lower the risk impacts: • Avoiding simultaneous outages of additional risk-significant components during the Completion Time of the LPI and RBS system trains. These components whose simultaneous outages are to be avoided, in addition to current TS requirements, include both Auxiliary Feedwater System (EWF) trains, both High Pressure Injection (HPI) trains (for reasons other than inoperable due to the associated LPI train), all three reactor building cooling (RBCU) trains, and their power supplies. • Defining specific criteria for scheduling only those preventive maintenance activities that can be completed within the 7 day Completion Time. • Assuring that the frequency of entry into the Condition and the average maintenance duration per year remain within the assumed values in the Topical Report. • Taking measures to assure that when maintaining the LPI and RBS trains, both are not made unavailable unless it is necessary. Can we exclude the unavailability hours that will be incurred during planned maintenance of large check valves and electric motor operated gate and globe valves in the Low Pressure Injection (LPI) System?		

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		Response: Yes, because the proposed change will permit meaningful LPI System train maintenance to be performed with the unit at power and should result in an increase in the reliability of the LPI system components. The Topical Report used a plant specific Probabilistic Risk Assessment (PRA) to assess the risk impact of increased LPI System unavailability. The NRC staff evaluated this Topical Report and found the proposed increase in the LPI Completion Time acceptable in its Safety Evaluation.		
50.3	IE03	Question: On September 4, 2004, Oconee Unit 1 was shutdown to inspect selected sections of Heater Drain piping. Although this inspection was driven from an August 2004 pipe failure at the Mahima Nuclear Plant in Japan, detailed planning for the Unit 1 shutdown did not begin until September 2, less than 72 hours prior to the outage. However, meetings and discussions had been held days earlier which recognized the potential need to bring Unit 1 off line for the piping inspections. Since this shutdown was pro-active and not driven by an equipment failure, Duke dispatching requested the shutdown occur September 4 (a holiday weekend) instead of September 11 which was initially proposed by the site. The NEI 99-02 criteria for reporting power changes of greater than 20% is for discovered off-normal conditions that require a power change of greater than 20% to resolve. Is the power change described above considered an unplanned power change for performance indicator reporting? Response: No.	12/15 Introduced 3/17 Discussed (Have licensee available for next meeting) 4/28 Tentative Approval	Oconee
50.5	IE01	Question: On December31, 2004, during Oconee Unit 3 startup, there was an unanticipated change in reactor power from about 3% to 6%. The control room operator was initiating a power increase to 15% to enable putting the turbine online. When the desired power level value was input into the integrated control system (ICS), without awaiting a rate input or the operator placing ICS in Auto, the system unexpectedly started rapidly raising reactor power at the maximum rate. The control room team quickly took action to mitigate the power excursion by reducing the ICS power demand setpoint. The regulating rod group was inserted at normal rod speed by the ICS as it responded to the new demand. Due to normal control system overshoot, the control rods were inserted sufficiently to place the reactor in a shutdown condition. The reason for the unexpected action by the ICS was due to a software error that was introduced during an update to the system during the refueling outage. Upon completion of the transient mitigation response, the control room team decided to complete the reactor shutdown via manual control rod insertion of the remaining rod groups in the normal sequence. The event resulted in a subcritical reactor with power range NIs reading zero due to rod motion properly requested from the ICS in response to operator mitigation of the initial transient and minor power excursion. The definition of "scram" as applied to the initiating events PI IE01 Unplanned Scrams is a rapid insertion of negative reactivity that shuts down the reactor (e.g. via rods, boron, opening trip breakers, etc.) A conservative reading of the definition results in the event meeting the definition of "Unplanned Scram" for the purpose of NRC PIs. However, it is unclear whether normal rod motion at ONS is considered "rapid". Question: Is the reactor shutdown described above considered a “scram” for performance indicator reporting? Response: Duke Power does not believe this event constitutes a “scram” per NEI 99-02 because the rod insertion was at the normal speed as opposed to “rapid” insertion via gravity in response to opening the reactor trip breakers. In addition, the event did not challenge or require any critical safety system which is the basis for measuring “scram” events per NEI 99-02. Therefore, the event did not constitute a “scram” because normal rod speed should not be considered “rapid” and the event did not meet the intended scope of events measured by the PI.	1/27 Introduced 3/15 Oconee revision (clarification) of Question 3/17 Discussed 4/28 Discussed	Oconee