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: The ROP working group is currently working to prepare a response.	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	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. The pump control logic prohibits restart of the feed pumps (both the turbine driven pumps and motor driven feed pump	3/21 Discussed 4/25 Discussed 5/22 Modified to reflect discussion of 4/25, On Hold 6/12 Discussed. Related FAQ 30.8	Perry

Attachment 10

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		(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: The ROP working group is currently working to prepare a response.		
30.8	IE02	Question: Many plant designs trip the main feedwater pumps on high reactor water level (BWRs), and high steam generator water level or certain other automatic trips (PWRs). Under what conditions would a trip of the main feedwater pumps be considered/not considered a scram with loss of normal heat removal?	5/22 Introduced 6/12 Discussed 9/26 Discussed. 10/31 Discussed	Generic
		Response: The ROP working group is currently working to prepare a response.		
32.3a	IE02	Question: An unplanned scram occurred October 7, 2001, during startup following an extended forced outage. The unit was in Mode 1 at approximately 8% reactor power with a main feed pump and low-flow feedwater preheating in service. The operators were preparing to roll the main turbine when a reactor tripped occurred. The cause of the trip was a loss of voltage to the control rod drive mechanisms and was not related to the heat removal path. Main feedwater isolated on the trip, as designed, with the steam generators being supplied by the auxiliary feedwater (AFW) pumps. At 5 minutes after the trip, the reactor coolant system (RCS) temperature was 540 degrees and trending down. The operators verified that the steam dumps, steam generator power operated relief valves, start-up steam supplies and blowdown were isolated. Additionally, AFW flow was isolated to all Steam Generators as allowed by the trip response procedure. At 9 minutes after the trip, with RCS temperature still trending down, the main steam isolation valves (MSIV) were closed in accordance with the reactor trip response procedure curtailing the cooldown. The RCS cooldown was attributed to steam that was still being supplied to low-flow feedwater preheating and #4 steam generator AFW flow control valve not automatically moving to its flow retention position as expected with high AFW flow. The low-flow feedwater preheating is a known steam load during low power operations and the AFW flow control issue was identified by the control room balance of plant operator. The trip response procedure directs the operators to check for and take actions to control AFW flow and eliminate the feedwater heater steam	1/23 Revised. Split into two FAQs 3/20 Discussed 5/1 Discussed 5/22 Tentative Approval 6/18 Discussion deferred to July 7/24 Discussed	DC Cook

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		supply. When this trip occurred the unit was just starting up following a 40 day forced outage. The reactor was at approximately 8% power and there was very little decay heat present following the trip. With very little decay heat available, the primary contribution to RCS heating is from Reactor Coolant Pumps (RCPs). Evaluation of these heat loads, when compared to the cooling provided by AFW, shows that there is approximately 3.5 times as much cooling flow provided than is required to remove decay heat under these conditions plus pump heat. This resulted in rapid cooling of the RCS and ultimately required closure of the MSIVs. Other conditions such as low flow feedwater preheating and the additional AFW flow due to the AFW flow control valve failing to move to its flow retention setting contributed to this cooldown, but were not the primary cause. Even without these contributors to the cooldown, closure of MSIVs would have been required due to the low decay heat present following the trip. It should also be noted that the conditions that are identified as contributing to the cooldown are not conditions which prevent the secondary plant from being available for use as a cooldown path. The AFW flow control valve not going to the flow retention setting increases the AFW flow to the S/G, and in turn causes an increase in cooldown. This condition is corrected by the trip response procedure since the procedure directs the operator to control AFW flow as a method to stabilize the RCS temperature. With low-flow feedwater preheating in service, main steam is aligned to feedwater heaters 5 and 6 and is remotely regulated from the control room. Low-flow feedwater preheating is used until turbine bleed steam is sufficient to provide the steam supply then the system is isolated. There are no automatic controls or responses associated with the regulating valves, so when a trip occurs, operators must close the regulating valves to secure the steam source. Until the steam regulating valves are closed, this is a steam load contributing to a cooldown. The low-flow preheating steam supplies are identified in the trip response procedure since they are a CNP specific design issue. The actions taken to control RCS cooldown were in accordance with the plant procedure in response to the trip. The primary reason that the MSIVs were required to be closed was due to the low level of decay heat present following a 40 day forced outage. The closure of the MSIVs was to control the cooldown as directed by plant procedure and not to mitigate an off-normal condition or for the safety of personnel or equipment. With the low decay heat present following the 40 day forced outage, there would not have been a need to reopen the MSIVs prior to recommencing the startup. Should the reactor trip described above be counted in the Unplanned Scrams with Loss of Normal Heat Removal Performance Indicator?		
		Response: Yes. The licensee's reactor trip response procedure has an "action/expected response" that reactor coolant system temperature following a trip would be stable at or trending to the no-load Tavg value. If that expected response is not obtained, operators are directed to stop dumping steam and verify that steam generator blowdown is isolated. If cooldown continues, operators are directed to control total feedwater flow. If cooldown continues, operators are directed to close all steam generator stop valves (MSIVs) and other steam valves. During the unit trip described, the #4 steam generator auxiliary feedwater flow control valve did not reposition to the flow retention setting as expected (an off normal condition). In addition, although control room operators manually closed the low-flow feedwater preheat control valves that were in service, leakage past these valves (a pre-existing degraded condition identified in the Operator Workaround database) also contributed to the cooldown. Operator logs attributed the reactor system cooldown to the #4 AFW flow control valve failure as well as to steam being supplied to low-flow feedwater preheating. As stated above, the trip response procedure directs operators to control feedwater flow in order to control the cooldown. Operator inability to control the cooldown through control of feedwater flow as directed is considered an off normal condition. Since the cooldown continued due to an off normal condition, operators closed the MSIVs, and therefore this trip is considered a scram with loss of normal heat removal.		
34.6	IE02	Question:	3/20 Introduced	STP

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		Should the following event be counted as a scram with loss of normal heat removal? STP Unit Two was manually tripped on Dec. 15, 2002 as required by the off normal procedure for high vibration of the main turbine. Approximately 17 minutes after the Unit was manually tripped main condenser vacuum was broken at the discretion of the Shift Supervisor to assist in slowing the turbine. Plant conditions were stabilized using Auxiliary Feedwater and Steam Generator Power Operated Relief Valves. Main Feedwater remained available via the electric motor driven Startup Feedwater pump. Main steam headers remained available to provide cooling via the steam dump valves. At any time vacuum could have been reestablished without diagnoses or repair using established operating procedures until after completion of the scram response procedures. Scrams with a Loss of Normal Heat Removal performance indicator is defined as *"The number of unplanned scrams while critical, both manual and automatic, during the previous 12 quarters that were either caused by or involved a loss of the normal heat removal path prior to establishing reactor conditions that allow use of the plant's normal long term heat removal systems."* This indicator states that a loss of normal heat removal has occurred whenever any of the following conditions occur: loss of main feedwater, loss of main condenser vacuum, closure of the main steam isolation valves or loss of turbine bypass capability. 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. The STP plant is designed to isolate main feedwater after a trip by closing the main feedwater control valves. The auxiliary feedwater pumps are then designed to start on low steam generator levels. This is expected following normal operation above low power levels and in turn provides the normal heat removal. This design functioned as expected on December 15, 2002 when the reactor was manually tripped due to high turbine vibration. Normal plant operating procedures 0POP03-ZG-0006 (Plant Shutdown from 100% to Hot Standby) and 0POP03-ZG-0001 (Plant Heatup) state if Auxiliary Feedwater is being used to feed the steam generators than the preferred method of steaming is through the steam generator power operated relief valves. This can be found in steps 7.4 and 7.5 of 0POP03-ZG-0001 and steps 6.6.5 and 6.6.10 of 0POP03-ZG-0006. The note prior to 6.6.10 states *"the preferred method for controlling SG steaming rates while feeding with AFW is with the SG PORVs"*. The normal heat removal path as defined in NEI 99-02 Revision 2 was in service and functioning properly for seventeen minutes after the manual reactor trip and would have continued to function had not the shift supervisor voluntarily broke condenser vacuum and closed the MSIV's. Interviews with the shift supervisor showed that the decision to break vacuum was two part. 1) Based on experience and reports from the field it was known that vacuum would need to be broken to support the maintenance state required for the main turbine and at a minimum to support timely inspection. 2)This would assist in slowing the turbine. The decision to break vacuum was not based solely on mitigating an off-normal condition or for the safety of personnel or equipment. Because Auxiliary Feedwater system had actuated and was in service as expected, the decision was made to use Auxiliary Feedwater and steam through the SG PORVs. As stated earlier, this is the preferred method of heat removal if the decision to use Auxiliary Feedwater is employed as supported by the normal operating procedures while the plant is in Mode 3. Main feedwater remained available via the electric motor driven Startup Feedwater pump and the main steam headers remained available to provide cooling via the steam dump valves if required. Discussion with the shift supervisor showed he was confident that at any time vacuum could have been readily recovered from the control room without the need for diagnoses or repair using established operating procedures if the need arose. An outside action would be required in drawing vacuum in that a Condenser Air Removal pump would require starting locally in the TGB. This is a simplistic, proceduralized and commonly performed evolution. Personnel are fully confident this would have been performed without incident if required. Closing the MSIVs and breaking vacuum as quickly as possible is not uncommon at STP. For a normal planned shutdown MSIVs are closed and vacuum broken within four to six hours typically to support required maintenance in the secondary. If maintenance in the secondary is known to be critical path than vacuum has been broken as early as three hours and fifteen minutes following opening of the main generator breaker. The only reason that vacuum is not	3/20 Discussed 6/18 Discussed; Question to be revised to reflect discussion 7/24 Discussed	

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		broken sooner is because in most cases it is needed to support chemistry testing. By limiting the flow path as described in NEI 99-02 for normal heat removal there is undue burden being placed on the utility. Only recognizing this one specific flow path reduces operational flexibility and penalizes utilities for imparting conservative decision making. Conditions are established immediately following a reactor trip (100% to Mode 3) that can be sustained indefinitely using Auxiliary Feedwater and steaming through the steam generator PORVs. This fact is again supported in the stations Plant Shutdown from 100% to Hot standby and Plant Heatup normal operating procedures. The cause of a trip, the intended forced outage work scope, or outage duration varies and inevitably will factor into which method of normal long term heat removal is best for the station to employ shortly following a trip.		
		Response: The ROP working group is currently working to prepare a response. Licensee Proposed Response: NO. Since vacuum was secured at the discretion of the Shift Supervisor and could have been restored using existing normally performed operating procedures, the function meets the intention of being available but not used.		
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. 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?	9/25 Introduced and discussed	Quad Cities
		Response:		

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		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 (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	9/25 Introduced and discussed	Peach Bottom

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		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 "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.		

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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?" 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.	1/22 Introduced 3/25 Discussed 6/16 Discussed	Ginna
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	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	Millstone 2

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		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.		
38.9	OR01	~~Question:~~ ~~On March 4, 2004, workers initiated a series of diving activities related to the inspection and repair of the Steam Dryer in the Dryer Separator Pit. On March 5, 2004, a contract diver proceeded to the Unit 1 Reactor Building 117' Elevation in preparation for the next diving evolution on the Steam Dryer. Based on underwater dose gradients from the steam dryer, 5 Electronic Dosimeters (EDs), 10 thermoluminescent dosimeters (TLDs) and a telemetry transmitter were placed on the diver by a Radiation Protection Technician (RPT) to monitor personnel exposure. ED/TLD combinations were placed on the chest, right arm, left arm, right leg, and left leg. TLDs were use to monitor the extremities. Communication between the EDs and the telemetry system was verified after placement on the diver. The RPT conducted the pre-dive radiological briefing and the diver entered the Contaminated Area. Telemetry problems were experienced prior to the diver entering the Dryer Separator Pit. The underwater antenna was changed out and telemetry problems appeared to be corrected. The diver was in the Dryer Separator Pit approximately 40 minutes when additional telemetry problems occurred. The diver was instructed to exit the water and the transmitter replaced. The telemetry problems were corrected and the diver re-entered the Dryer Separator Pit. After entering the water, the left arm ED stopped communicating with the telemetry system. The telemetry computer was rebooted while the diver was in the Dryer Separator Pit, but the left arm ED failed to transmit. The RP Supervisor evaluated the situation and decided to allow the dive to continue since four of the five EDs were transmitting properly. The left arm ED did not transmit for the remainder of the dive. However, it did remain functional and continued to accumulate dose. Upon completion of the work, the diver exited the Dryer Separator Pit and it was discovered that his left arm ED was in alarm. Specific ED results for the diver are given below:~~	7/22 Introduced 8/18 Additional information required Referred to HP group 10/13 Licensee providing additional information to HP group 1/27 Discussed 3/17 Withdrawn	Brunswick

~~ED Location~~	~~ED Result (mrem)~~
~~Chest~~	~~147~~
~~Right Arm~~	~~319~~
~~Left Arm~~	~~588~~
~~Right Leg~~	~~30~~
~~Left Leg~~	~~31~~

~~Per the RWP, the Administrative Dose Limit for the dive was 500 mrem.~~
~~The diver's TLDs were processed and the results are given below~~

~~TLD Location~~	~~TLD Result (mrem)~~
~~Chest~~	~~135~~
~~Right Arm~~	~~403~~
~~Left Arm~~	~~673~~
~~Right Leg~~	~~30~~

TempNo.	PI	Question/Response	Status	Plant/ Co.
		~~Left Leg~~ | ~~34~~ ~~Head~~ | ~~216~~ ~~Does the situation described above constitute an unintended exposure occurrence in the Occupational Radiation Safety Cornerstone as described in NEI 99-02?~~ ~~Response:~~ ~~NEI 99-02 identifies the dose value used as a screening criterion to identify an unintended exposure occurrence as 100 mrem. The administrative dose guideline was established in the RWP as 500 mrem. Since the ED was functional and read 588 mrem, the screening criterion in 99-02 was not exceeded.~~		
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 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	8/18 Introduced 9/16 On hold for more information 11/18 Discussed 12/15 Discussed 1/27 Discussed	Brunswick

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		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 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?	10/13 Introduced 12/15 Discussed 1/27 Discussed	Harris
		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	10/13 Introduced 12/15 Discussed 1/27 Discussed	Perry

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		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?		
		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." 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?	11/18 Introduced 12/15 Discussed 1/27 Discussed	Beaver Valley
		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)".		
40.5	IE02	Question: NEI 99-02R2, Pages 15-16, states:	11/18 Introduced 12/15 Discussed	SONGS

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		"Loss of the normal heat removal path: when any of the following conditions have occurred and cannot be easily recovered from the control room without the need for diagnosis or repair to restore the normal heat removal path: ... failure of turbine bypass capacity that results in insufficient bypass capability remaining to maintain reactor temperature and pressure" ... 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... *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. 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."... *"Example of loss of turbine bypass capability:* sustained use of one or more atmospheric dump valves (PWRs)... *"Examples that do not count:* ...partial losses of condenser vacuum or turbine bypass capability after an unplanned scram in which sufficient capability remains to remove decay heat..." On June 4, 2004, Unit 3 was manually tripped due to a heavy influx of red sea grass on the intake to the circulating water pumps. This resulted in securing of 3 of the 4 circulating water pumps. Following the trip, one circulating water pump remained in service and maintained normal condenser vacuum. However, approximately 5 minutes post-trip the Steam Bypass Control System began to not function as designed in auto (later determined to be a faulty permissive channel), and the operators choose to transfer to the Atmospheric Steam Dump Valves (ADVs) to control RCS temperature. The MSIVs remained open and one quadrant of the condenser remained available. Since ADVs are a procedural option to use, and they were working as designed, the choice to look into whether or not the SBCS control valves would function in manual was not pursued. Since the problem with the SBCS was in the permissive circuit the SBCS valves would have operated as expected from the control room in Automatic (with manual permissive). W believe we meet the requirement for a normal heat removal flow path, and the use of the ADVs were elective on the part of the Operators. In summary, there was not: (1) a complete loss of all main feedwater flow; (2) insufficient main condenser vacuum to remove decay heat; (3) complete closure of at least one MSIV in each main steam line; nor (4) failure of turbine bypass capacity that results in insufficient bypass capability remaining to maintain reactor temperature and pressure. Nevertheless, since there was prolonged operation of the ADVs, is this considered a loss of turbine bypass capability and therefore a loss of RCS heat removal? Response: ~~No, operation of the ADVs alone does not constitute a SCRAM with loss of normal heat removal. Therefore the event does not count as an unplanned SCRAM with loss of normal heat removal, because:~~ ~~(1)Operators electively used the ADVs in lieu of the SBCS;~~ ~~(2)MSIVs remained open;~~ ~~(3)One quadrant of the condenser was available; and~~ ~~The SBCS was capable of performing its intended safety function in manual.~~ No. Although operators chose to use the Atmospheric Dump Valves, the normal heat removal path remained available (the Main Steam Isolation Valves remained open, the condenser was available, and the Steam Bypass Control System was available and would have operated as expected from the control room in automatic [with manual permissive]).	1/27 Tentative Approval 2/17 DJW response revision	
40.6	BI02	Question: NEI 99-02R2, Page 80, lines 33-34 states: "For those plants that do not have a Technical Specification limit on Identified Leakage, substitute RCS Total Leakage in the Data Reporting Elements." The RCS total leak rate at SONGS has historically been approximately 0.1 gpm with the identified leakage being approximately one-third of that value (i.e., ~0.03 gpm). Due to low leak rate calculations, instrument uncertainties,	11/18 Introduced 12/15 Discussed 1/27 Tentative Approval 2/18 SCE response revision.	SONGS

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		and computer modeling, when the total leak rate was less than 1 gpm the identified leak rate equaled or exceeded the total leak rate 55 times from January 2001 to May 2002. Since identified leakage cannot exceed total leakage. SONGS stopped calculating identified leakage if total leakage was less than 1 gpm. The PI reporting requirement is the maximum monthly value of ***identified leakage*** but since we do not calculate this unless it is greater than or equal to 1 gpm, we have reported ***total leakage*** with an appropriate comment (stating this each month). Even though we have a Technical Specification limit on identified leakage [10 gpm], we have opted to report the more conservative value of total leakage. Is this acceptable?		
		Response: ~~Licensees may elect to be conservative and over-report the total leak rate in lieu of the identified leak rate. However, use of the total leak rate in lieu of identified leak rate must be noted in the Comment Section of the B02 PI data submittal.~~ Licensees who want to use this FAQ's methodology may do so if their plant procedures are appropriately revised, and licensees must annotate in the comment section of each data submittal that the analysis is based on total leakage.		
40.7	MS04	Question: Appendix D BFN 1 needs to remove blanks installed in spectacle flanges in RHR service water piping on the A and C trains to restore service water flow capability to the 1A & 1C RHR heat exchanger as part of BFN 1 restart test and system turnover. To remove these system boundary blanks, the service water to the related U2 and U3 RHR heat exchangers will have to be removed from service. The U2 and U3 RHR system each contain 2 100% capacity RHR headers each with two 50% capacity heat exchangers. The heat exchangers are paired as A & C in one header and B & D in the other. The U1 restoration work is planned such that during time the A RHR heat exchanger on U2 and U3 is out of service, the service water supply to the C heat exchangers will remain available. When the C RHR heat exchanger on U2 and U3 is out of service the service water to the A heat exchangers will remain available. The work to remove the blanks can easily be performed within the Tech Spec AOT of 30 days for an RHRSW Heat Exchanger. The work is planned to take approximately 34 hours per heat exchanger train. This potential out of service time would equate to approximately 5% of the available hours to the green threshold for each unit. This FAQ seeks approval to exclude the unavailability on the U2 and U3 A & C trains of RHR due to support system unavailability during this planned Unit 1 restart activity. Can a one time site specific exemption be granted to exclude from the ROP SSU RHR PI the planned unavailability on BFN U2 and U3 A & C trains that result from the BFN 1 RHR service water restoration activities?	11/18 Introduced 1/27 Tentative Approval 2/17 DJW Response revision	Browns Ferry
		Response: ~~Unavailability need not be counted against the U2 and U3 during the U1 RHR Service water restoration activities since this is a one time RHR support system unavailability event that can be contributed solely to a planned BFN U1 restart activity~~Yes. The effect of the Browns Ferry Nuclear (BFN) Unit 1 Residual Heat Removal (RHR) service water restoration activities on Unit 2 and Unit 3 RHR system availability is a unique condition that had not been anticipated during the development of the PI guidance document. The unavailability of the Unit 2 and Unit 3 RHR system due to the Unit 1 restoration work does not truly reflect the performance of these systems. For this unique, one-time-only activity, the planned unavailability of the BFN Unit 2 and Unit 3 RHR system unavailability due to the BFN Unit 1 RHR service water restoration may be excluded from the RHR safety system unavailability PI.		
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?	11/18 Introduced 1/27 Discussed. Response to be revised by NRC. 2/17 DJW Response revision.	Limerick

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		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 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: ~~.No. Based upon the NEI 99-02 guidance, fault exposure is not taken for failures due to a design deficiency that was not capable of being discovered during normal surveillance tests. Even though the event was caused by a combination of design and procedural deficiencies, the presence of air in the RCIC system is solely due to the inadequate RCIC system design that existed for a long period of time, which could not be detected during normal surveillance testing, and which was identified during diagnostics and analysis.~~ Yes, fault exposure hours should be taken. The RCIC system was unavailable due to voids in the RCIC and HPCI system suction piping. The voids were caused, at least in part, by procedural inadequacies that resulted in an inadequate system fill. The RCIC system was discovered to be unavailable during the first performance of a routine surveillance test following the inadequate system fill.		
40.9	IE01	Question: On November 22, 2003, Salem 2 initiated a reactor startup at 2210 following refueling. The reactor was declared critical at 0106 on November 23, 2003. At 0226, low power physics testing began. Based on a review of information from the plant computer, the reactor was subcritical prior to this event. With low power physics testing continuing, a control rod dropped into the reactor core, causing the subcritical reactor to become more subcritical. At 0507, the Operating crew entered the abnormal procedure for a dropped control rod. Based on the reactor being in a subcritical condition, the abnormal procedure directs all rods to be inserted. The procedure does not require all rods to be	12/15 Introduced 1/27 Discussed	Salem

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		inserted if the reactor remains critical. At 0519, following a crew brief, the reactor was manually tripped per procedure as directed by the Control Room Supervisor. NRC POSITION The NRC resident office has indicated that an unplanned scram should be counted for this event. The inspectors believe that the appropriate guidance in NEI 99-02, Revision 2, which should be followed begins on line 39 of page 12. This guidance states that the types of scrams that should be included are: "Scrams that resulted from unplanned transients, equipment failures, spurious signals, human error, or those directed by abnormal, emergency, or annunciator response procedures." BASIS FOR NRC POSITION The inspectors considered that for the conduct of physics testing, the reactor was maintained critical or if subcritical, very near critical. In fact the main control room logs did not distinguish otherwise and only included a log entry stating that the reactor was critical. The inspectors also considered that many transients may actually render the reactor subcritical before the resultant scram is inserted. It is the intent of this PI to count all unplanned transients that begin while the reactor is critical and result in an unplanned reactor scram. The November 23, 2003, manual reactor trip was immediately preceded by plant conditions that maintained the reactor very near critical or critical. PSEG POSITION This was not reported as an Unplanned Scram in November 2003 because the scram occurred while the reactor was subcritical. A review of the post-trip review and notification documentation indicate that both the Operations Superintendent and the Control Room Supervisor were aware of the fact that the reactor was subcritical prior to the trip and that there was a procedural requirement to insert all rods if the reactor was subcritical as a result of the dropped rod. Tripping the reactor is a conservative method to insert the rods. BASIS FOR PSEG POSITION PSEG utilized the following guidance from Section 2.1, Initiating Events Cornerstone, of NEI 99-02 to determine that the subcritical scram should not be counted: • Page 11, Lines 24 – 26, Indicator Definition is the number of unplanned scrams during the previous four quarters, both manual and automatic, while critical per 7000 hours. • Page 11, Lines 28 – 31, Data Reporting Elements, instruct licensees to report the number of unplanned automatic and manual scrams while critical in the previous quarter • Page 12, Lines 1 – 4, Calculation, demonstrates that the value for this PI is derived by multiplying the total unplanned scrams while critical in the previous 4 quarters by 7000 hours and dividing the result by the total number of hours critical in the previous 4 quarters • Page 12, Lines 16 – 17, defines criticality as existing when a licensed operator declares the reactor critical. The scram in question occurred after the reactor was verified to be subcritical. • Page 12, Lines 17 –19, states that there may be instances where a transient initiates from a subcritical condition and is terminated by a scram after the reactor is critical and that these conditions count as a scram. The guidance specifically requires that the reactor must be critical at the time of the scram. The relevant condition is to determine if the reactor is critical at the time of the scram and, if so, is reportable under this PI. • Page 12, Line 30 states that dropped rods are not considered reactor scrams. • Page 13, Lines 4 and 9 state that an example of a scram that is not included in this PI is Reactor Protection System actuation signals that occur while the reactor is subcritical. Should this event be counted as an Unplanned Scram?		
		Response: No. This PI, as defined, counts only critical scrams; therefore, the scram defined in this question does not count		

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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 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	12/15 Introduced	Oconee

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		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 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	12/15 Introduced	Oconee

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		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?		
		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?	12/15 Introduced	Oconee
		Response: No.		
50.4	IE03	Question: NEI 99-02 specifically requests an FAQ for this condition: Anticipated power changes greater than 20% in response to expected problems (such as accumulation of marine debris and biological contaminants in certain seasons) which are proceduralized but cannot be predicted greater than 72 hours in advance may not need to be counted if they are not reactive to the sudden discovery of off-normal conditions. The circumstances of each situation are different and should be identified to the NRC in an FAQ so that a determination can be made concerning whether the power change should be counted. **Event Description:** On August 31, 2004, Unit 2 experienced a trip of the 2D Circulating Water Intake Pump	12/15 Introduced 1/27 Discussed	Brunswick

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		(CWIP). This caused a reduction in condenser vacuum, which was mitigated by a 21% power reduction. The CWIP tripped due to a high differential pressure on the traveling screen, (i.e., a moving screen upstream of the pump intake that removes debris and marine growth.) Increased accumulation of debris and marine growth on the traveling screens is an expected condition during extreme lunar tides, as was the case on August 31. Although the timing and potential vulnerability of the lunar low tide was known, it was not possible to predict if, or when, an excessive influx of marine growth or debris would occur. The plant was in a "high vulnerability" condition, meaning that conditions in the intake canal were more likely to challenge the traveling screens and CWIPs. The marine growth is a particular nuisance in the summer months during periods of lower tides. The increased canal bottom temperature during these periods causes organic debris to decay at a higher rate and tends to produce more suspended solids in the intake water. Plant operating experience includes several instances when traveling screens have experienced high differential pressures and CWIP trips. For example, LER 2-1999-006, "Automatic Reactor Shutdown Due to Condenser Low Vacuum Main Turbine Trip" documents a similar event. Mitigating actions have been taken, such as canal dredging; however, these changes must be compatible with state environmental water quality regulations. Therefore, changes to reduce traveling screen clogging, such as increasing the mesh sizing on traveling screens, are limited in their effectiveness. On August 30, 2004, Unit 1 traveling screens received high differential pressure alarms. As a result, both units' traveling screens were placed in the "hand fast" position. The procedure for intake canal blockages includes steps for high vulnerability conditions, such as ensuring the traveling screens are operating in "hand fast" speed and reducing reactor power for a sustained high differential pressure. Both units' screens remained in this alignment throughout the event; however, the increase in the 2D screen differential pressure was too rapid to counteract with mitigating actions to prevent the pump trip.		
		Response: This event should not be counted as an unplanned power change. The high vulnerability condition in the intake canal was anticipated; however, the potential for rapid accumulation of debris was not predictable greater than 72 hours in advance. In addition, the response to the high vulnerability intake canal condition is proceduralized..		
50.5	IE01	Question: On December 13, 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. ~~Control rods were inserted 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.~~ 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	1/27 Introduced 3/15 Oconee revision (clarification) of Question	Oconee

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		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.		
371	EP02	This FAQ has been withdrawn and replaced by FAQ XXX		
51.1	EP02	This FAQ is a replacement for FAQ 371 which has been withdrawn. This FAQ changes the date the FAQ is effective from 1/1/05 to 4/1/05 and applies to data submitted for the second quarter of 2005 going forward. Question: NEI 99-02 Rev 2 ERO Participation PI defines the numerator and denominator of the calculation as based on Key ERO Members. The key position list (on page 89 and 90) was originally created from NUREG 0696 key functions that involved actions associated with the risk significant planning standards (classification, notification, PARs, and assessment), with the addition of the Key OSC Operations Manager included from a mitigation perspective. When a single individual is assigned in more than one 'key position' that individual must be counted for each key position (page 91 lines 4-7 of NEI 99-02). Guidance is not provided in the case where more than one key position is performed by a single member of the ERO in a single drill/exercise. For example, the communicator is defined in NEI 99-02 as the key position that fills out the notification form, seeks approval and usually communicates the information to off site agencies (these duties may vary from site to site based on site procedures). Assigning a single member to multiple Key Positions and then only counting the performance for one Key Position could mask the ability or proficiency of the remaining Key Positions. The concern is that an ERO member having multiple Key Positions may never have a performance enhancing experience for all of them, yet credit for participation will be given when any one of the multiple Key Positions is performed. When the communicator key position is performed by an ERO member who is also assigned another key position (e.g., the Shift Manager (Emergency Director)), should participation be counted for two key positions or for one key position?		

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		Response: Participation by a single member of the ERO performing multiple key positions should be counted for each key position performed. For the situation described, two key positions should be counted. ERO participation should be counted for each key position, even when multiple key positions are assigned to the same ERO member. In the case where a utility has assigned two or more key positions to a single ERO member, each key position must be counted in the denominator for each ERO member and credit given in the numerator when the ERO member performs each key position "Assigned" as used in this FAQ applies to those ERO personnel filling key positions listed on the licensee duty roster on the last day of the reporting period (quarter). Note, however, the exception on page 92 line 1-2 of NEI 99-02, that states, "All individuals qualified to fill the Control Room Shift Manager/Emergency Director position that actually might fill the position should be included in this indicator." This FAQ will become effective 4/1/05 and applies to data submitted for the second quarter 2005 and going forward		
376	EP03	This FAQ has been withdrawn. The issue is under review.		
51.2	EP03	This FAQ is a replacement for FAQ 376 which has been withdrawn. This will be added to Appendix D of NEI 99-02 as part of Revision 3. Question: Catawba Nuclear Station has 89 sirens in their 10-mile EPZ; 68 of these are located in York County. Duke Power's siren testing program includes a full cycle test for performance indicator purposes once each calendar quarter. On Tuesday, September 7, 2004, York County sounded the sirens in their county's portion of the EPZ to alert the public of the need to take protective actions for a Tornado Warning. Catawba is uncertain whether to include the results of the actual activation in their ANS PI statistics. The definition in NEI 99-02 does not address actual siren activations. In contrast, the Drill/Exercise Performance (DEP) Indicator requires that actual events be included in the PI. Should the performance during the actual siren activation be included in the Alert and Notification System (ANS) Performance Indicator Data? Response: For this instance, Catawba may include the results of the September 7, 2004 actual siren activation data results in their ANS PI data. However, for all future instances, no actual siren activation data results shall be included in licensees' ANS PI data.	Introduced 3/17	Catawba