Temp No.	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

Attachment 8

<table>
<tr><th>Temp No.</th><th>PI</th><th>Question/Response</th><th>Status</th><th>Plant/ Co.</th></tr>
<tr><td rowspan="2">28.3</td><td rowspan="2">IE02</td><td>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 (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?</td><td rowspan="2">3/21 Discussed
4/25 Discussed
5/22 Modified to reflect discussion of 4/25, On Hold
6/12 Discussed.
Related FAQ 30.8
10/31 Tentative Approval</td><td rowspan="2">Perry</td></tr>
<tr><td>Response:
The ROP working group is currently working to prepare a response.</td></tr>
<tr><td>30.8</td><td>IE02</td><td>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?</td><td>5/22 Introduced
6/12 Discussed
9/26 Discussed.
10/31 Discussed</td><td>Generic</td></tr>
</table>

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response: The ROP working group is currently working to prepare a response.		
31.5	MS04	Question Appendix D Sequoyah Nuclear Plant (SQN) has two units. Each Unit has three trains of AFW, two motor driven trains (A train and B train), and one turbine driven train (Terry Turbine train, A or B train power). All three trains have Level Control Valves (LCVs) that are the steam generator injection valves. The LCVs are normally closed, air operated valves that auto open when AFW receives a start signal. The valves fail open when air is removed from them. SQN uses Control Air as the normal air supply to the LCVs. Control Air is not a seismically qualified, 1E system. Auxiliary Air is the LCV's standby, safety related air supply. A train Auxiliary Air feeds two Terry Turbine train LCVs and the two motor driven A train LCVs. B train Auxiliary Air feeds the other two Terry Turbine train LCVs and the two motor driven B train LCVs. Auxiliary Air automatically starts whenever the Control Air pressure drops below its setpoint. The Terry Turbine train LCVs also have accumulator tanks and high pressure air cylinders to control them during a loss of all power. The Terry Turbine train LCVs can be controlled from the main control room for one hour after the loss of all air using the accumulator tanks. For all scenarios except a major secondary system pipe rupture, the fail open LCVs are conservative, as they allow AFW to deliver the required flow. During a major secondary system pipe rupture, AFW is required to be isolated from the faulted steam generator. In the absence of both Control Air and Auxiliary Air, manual action at the LCVs will have to be taken to isolate the corresponding motor driven AFW train from the faulted steam generator. This action is proceduralized in Emergency Procedures and Abnormal Operating Procedures. The PSA also models the AFW system as available while Auxiliary Air is taken out of service. Since the PSA models the AFW system as available while Auxilary Air is unavailable (gives credit for the manual isolation of motor driven AFW trains) and the manual actions are proceduralized and trained on, is it correct to be consider the affected train(s) of AFW as still available during the periods when Auxiliary Air is taken out of service?	8/22 Introduced 3/20 Tentative Approval	Sequoyah
		Response: Yes, unavailability need not be reported when auxiliary air is not available to the AFW FCVs, as long as at least one train of support system air remains available.		

Temp No.	PI	Question/Response	Status	Plant/ Co.
31.7	EP03	Question: During a recent Nuclear Regulatory Commission (NRC) inspection of the Alert and Notification System (ANS) Reliability Performance Indicator (PI) at Calvert Cliffs Nuclear Power Plant (CCNPP), the inspector identified an issue concerning how CCNPP reports weekly silent test results for the ANS PI. While reviewing the ANS PI data, the inspector observed that weekly silent testing consisted of transmitting three consecutive initiation signals during the scheduled silent activation test. The inspector also observed that when reporting the PI data, CCNPP reports the three initiation signals as one test and reports the test as a success if at least one out of three initiation signals is received. When none of the three initiation signals is received, the test is considered an unsuccessful silent activation. The inspector determined that by not counting and reporting each of the three initiation signals as separate siren tests, CCNPP could be unintentionally masking failures and may not be meeting the intent of the ANS PI. This issue was documented in NRC Inspection Report 50-317/02-010, 50-318/02-010, dated August 12, 2002, as an Unresolved Item. Beginning in June 2001, the Calvert County procedure for activating the siren system during an actual emergency was revised to require the transmission of three sets of initiating tones to activate the sirens for one cycle. Coincident with this revision, the weekly silent test procedure was revised to mimic the full siren activation process during an actual emergency. The current CCNPP ANS is designed with no direct feedback mechanism or polling operation for siren activation. At Calvert Cliffs, we utilize three sets of initiating tones to simulate newer system designs that provide feedback and poll a receiver until it responds. This methodology minimizes the effect of momentary channel interference, provides greater assurance that each siren will perform its function, and allows us to monitor individual siren performance. The change in activation and testing methodology was not submitted to FEMA for approval prior to use. When activating sirens during an actual emergency and during weekly silent testing the following procedure is used. The 911 dispatcher checks to make sure the radio channel is clear. The 911 dispatcher makes an announcement that the Calvert Cliffs Public ANS is being sounded (or tested for silent testing). The 911 dispatcher selects the CCNPP Sirens icon. A 911 supervisor verifies that the correct icon is selected. The 911 dispatcher selects the transmit icon to send the first set of tones. The 911 dispatcher then waits 10 seconds and when the channel is clear, repeats the announcement, selects the icon, waits for supervisor verification, and sends the second set of tones. The 911 dispatcher then waits 10 seconds and when channel is clear, repeats the announcement, selects the icon, waits for supervisor verification, and sends the third set of tones. When the third set of tones have cleared, the 911 dispatcher makes an announcement that the siren activation is completed. It takes approximately one minute or less to transmit the three sets of initiating tones for a siren activation during the actual emergency and weekly silent test. We have reviewed siren testing data since the beginning of 2002 to identify whether sirens that received less than three initiation signals were capable of receiving the initiation signals during the next week's silent siren tests. This review indicated that out of 60 instances where a siren received less than three initiation signals, there was only one instance where a siren did not receive any of the three initiation signals during the next week's silent siren test. This does not include the times when a transmitter failure occurred causing multiple siren failures. The review of the data confirms that, for the most part, sirens receiving less than three initiation signals due to possible intermittent transmitter or receiver failures were capable of receiving at least one of the three initiation signals during the next week's silent siren tests. Given the testing methodology described above, is CCNPP reporting the results of weekly silent tests correctly?	9/26 Introduced 10/31 Discussed 1/23 Discussed. Query sent to FEMA 3/20 Discussed	Calvert Cliffs
		Response: The ROP working group is currently working to prepare a response.		
32.2	MS02 MS04	Appendix D Question: Component cooling water (CCW) system at our plant is a clean treated water cooling system that supports the High pressure safety injection (HPSI) pumps and Residual heat removal (RHR) system. Our commitment to Generic Letter 89-13, "Service	9/26 Introduced 10/31 Discussed 1/23 Discussed	St. Lucie

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Water System Problems Affecting Safety-Related Equipment" includes routine tube side (intake cooling water) cleanings. This FAQ seeks an exemption from counting planned overhaul maintenance hours for a support system outage (CCW heat exchanger maintenance). The CCW system transfers heat from the HPSI pump seal and bearing coolers and the RHR system to the ultimate heat sink. Sulzer Pumps Inc. Document E12.5.0730, "Qualification Report for HPSI Pump Bearings and Mechanical Seals without Cooling Water" has concluded the HPSI pumps can be operated without the use of CCW. The RHR system, therefore, is the only mitigating system as defined in NEI 99-02 requiring CCW as a support system. Our response to Generic Letter 89-13, "Service Water Problems Affecting Safety-Related Equipment" included routine maintenance and cleaning of the CCW heat exchangers. Work duration typically lasts for 45 to 50 hours while the Unit is in a 72 hour Technical Specification LCO. These activities function to remove micro and macro fouling thereby maintaining the heat transfer capability and reliability of the heat exchanger. These activities are undertaken voluntarily and performed in accordance with an established preventive maintenance program to improve equipment reliability and availability and as such are considered planned overhaul maintenance as defined in NEI 99-02. Other activities may be performed with the planned overhaul maintenance provided the system outage duration is bounded by the overhaul activities. NEI 99-02 goes on to state the following: "This overhaul exemption does not normally apply to support systems except under unique plant-specific situations on a case-by-case basis. The circumstances of each situation are different and should be identified to the NRC so that a determination can be made. Factors to be taken into consideration for an exemption for support systems include (a) the results of a quantitative risk assessment, (b) the expected improvement in plant performance as a result of the overhaul activity, and (c) the net change in risk as a result of the overhaul activity." In accordance with the NEI guidance the following results can be expected: Based on the plant on-line risk monitor (OLRM), the incremental change in core damage probability (ICCDP) and incremental change in large early release probability (ICLERP) over a 72 hour duration due to unavailability of a RHR train is less than 3E-08 and 1E-09 respectively. The ICCDP and ICLERP is considered small based on guidance in RG 1.177. The total change in core damage frequency (delta CDF) and change in large early release frequency (delta LERF) assuming each train of RHR is out-of-service for a 72 hour CCW heat exchanger maintenance window is, therefore, less than 6E-08/yr. and 2E-09/yr, respectively. Using a 72 hour duration for the risk assessment (the maximum allowed time based on the Technical Specification LCO) adds conservatism to this assessment. Historically this CCW maintenance has been completed within approximately 50 hours. The assessment results conclude that the delta CDF and delta LERF is in region III of RG 1.174 Figures 3 and 4 and is thus considered very small. Routine cleaning maintains the heat transfer capability from the RHR system to the ultimate heat sink by removing biofouling, silt, and other marine organisms from the heat exchangers. Shells lodged in the CCW heat exchanger tubes that have historically caused accelerated flow and erosion of the tube wall are also removed. The eddy current testing (ECT) and plugging activities have helped to identify and remove degraded tubes from service, thereby reducing the probability of CCW system inventory loss. These efforts have combined to increase the component and system reliability and availability. It is judged that the reliability increase from cleaning the CCW heat exchangers and identification of degraded tubes before failure offsets the small increase in risk resulting from the additional RHR system unavailability.	3/20 Tentative Approval	

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		Response: The tasks listed in NEI 99-02 (starting on page 28, line 20, of Revision 2) were included as examples of items that may be accomplished during an overhaul, however, taken individually these activities may not warrant consideration as an overhaul. Although "cleaning" is listed as a task that may be included in an "overhaul," cleaning alone does not constitute overhaul hours. When the planned maintenance of the heat exchanger includes additional activities, such as eddy current testing, the maintenance of the heat exchanger may be considered planned overhaul maintenance unavailability hours of an RHR support system and these hours would not need to be cascaded to the RHR system. The exemption from counting planned overhaul maintenance hours may only be applied once per train per operating cycle.		
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 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	1/23 Revised. Split into two FAQs 3/20 Discussed	DC Cook

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		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: The ROP working group is currently working to prepare a response.		
32.3b	IE02	Question: An unplanned scram occurred on July 22, 2002, during full power operations. The trip was initiated by a turbine trip caused by low vacuum in the 2C Condenser. The low vacuum was considered a partial loss of vacuum, and therefore was not counted as a loss of heat removal. At 3 minutes after the trip, the operators performed a main steam isolation due to the lowering RCS pressure that approached the Safety Injection set point and lowering Tavg due to AFW. This drop in RCS pressure is a design feature of Westinghouse plants with a large Tavg program. A rapid outsurge from the Pressurizer occurs when the RCS hot leg rapidly cools down from over 600 degrees to 547 degrees. The alignment of the auxiliary steam loads to the Unit 2 main steam system was the condition originally identified that resulted in the excessive cooldown. However, further review of this transient using the plant simulator provides additional insight into the plant response following a trip from full power. A review of plant trip response was performed to determine if the plant responded as expected and as per design. The plant RCS temperature and pressure response in July 2002 is similar to historical trips. Simulator scenarios were run to examine plant response to a normal reactor trip. Specifically, the Pressurizer pressure response and the response of Tavg to AFW throttling were observed. The pressure response was observed to ensure the simulator modeled what the Operators were seeing in the plant. Scenarios were run from full power, equilibrium, MOL conditions with Aux Steam aligned to Unit 2. Pressurizer Pressure lowered to about 1930 psi within one minute following the reactor trip. This closely matches the pressure response noted on the July 22, 2002 trip of Unit 2. As stated above, this drop in RCS pressure is a design feature of Westinghouse plants with a large Tavg program. The SI actuation setpoint for Unit 2 is 1900 psi. The SI setpoint was never reached during simulator testing. This is consistent with Pressurizer design which states that the Pressurizer is sized such that the Emergency Core Cooling Signal will not be activated during reactor trip and turbine trip (UFSAR Sect. 4.2.2.2). The lowest pressure reached was observed to occur within the first minute following the trip and was recovering soon after the minimum value was reached. The minimum value of pressure reached was observed to be independent of any RCS cooldown that occurred following the initial hot leg temperature reduction resulting from the reactor trip. During the time Tavg was lowering and <547 degrees, Pressurizer pressure was rising toward the program value of 2235 psi. The scenario was run using current Cook Plant EOPs and the Operator throttling AFW flow in Step 1 of ES-0.1 about 8 minutes after the Trip. It took 2 to 3 minutes to stabilize AFW flow at about 300Klbm/hr total. Tavg continued to lower for another 2 minutes, and was <543 degrees before it stopped lowering and began to recover. This means that at least 4 to 5 minutes passed from the time the crew began taking action to stop the RCS cooldown and Tavg actually stabilized and began to recover. This is similar to the responses seen in the plant following a reactor trip. Operators initially perform Immediate Actions in Procedure E-O to verify proper plant response. Operators observe key plant parameters during the Immediate Actions to determine whether an automatic SI setpoint has been reached or is being	1/23 Revised. Split into 2 FAQs 3/20 Tentative Approval	DC Cook

Temp No.	PI	Question/Response	Status	Plant/ Co.
		approached. If an automatic SI setpoint has been reached or is being rapidly approached, the Operators may take the action to manually actuate SI. As discussed above, RCS pressure rapidly decreases following a plant trip, approaching the SI setpoint of 1900 psi. Simulator response has shown that RCS pressure can go as low as 1930 psi. Operators are trained to take manual action to prevent inadvertent SI actuation. On July 22, 2002 Operators saw both RCS pressure and temperature rapidly decreasing and conservatively took action to close MSIVs to curtail RCS cooldown and prevent RCS pressure from lowering to the SI setpoint. The actions taken to control RCS cooldown were in accordance with plant procedures in response to the trip. 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. Should the reactor trip described above be counted in the Unplanned Scrams with Loss of Normal Heat Removal Performance Indicator Response: The ROP working group is assessing this question.		
33.1	OR01	Question: Plant Technical Specifications state the following for areas with radiation levels > or = 1000 mrem/hr, referred to as Tech Spec Locked High Radiation Areas (TSLHRAs): "...areas with radiation levels > or = 1000 mrem/hr shall be provided with locked or continuously guarded doors to prevent unauthorized entry, and the keys shall be maintained under the administrative control of Operations or health physics supervision. Doors shall remain locked except during periods of access by personnel under an approved RWP that shall specify the dose rate levels in the immediate work areas and the maximum allowable stay times for individuals in those areas..." Our plant is configured with a chain link cage and cage door around the outer Containment door. The cage door is secured by a chain and padlock (keys controlled by health physics supervision). Additionally, an electronic lock and card reader (ACAD) secures the door. Power to the ACAD lock is controlled by Security from a central remote location. When powered, the ACAD will open the electronic lock upon reading the badge of an individual with authorized access. When power is removed, the ACAD electronic lock cannot be opened from outside the cage and therefore acts as a locked door. The door will open from inside the cage via use of a crash bar, a feature which prevents the de-energized ACAD from locking people inside. Plant procedures state that the Shift Supervisor (Operations) authorizes each entry into Containment and assigns responsibility to the work group supervisor or entering individuals (entering Containment) to sign on and off an entry data sheet and the controlling RWP. The necessity for an access control point is determined by the Shift Supervisor and may be judged unnecessary. The typical entry without a continuous access control point (as in a nonoutage situation) requires notification to HP to remove the chain and padlock, and notification to Security, to dispatch a security officer to the cage door after which power to the ACAD is turned on. Entry into Containment is made in accordance with the RWP. If the entry duration is not brief, and no access control point is established, then the security officer may notify the central station to remove ACAD power and he departs resuming other activities. The de-energized ACAD maintains the cage door locked. Personnel inside Containment may still exit in an emergency, unassisted, using the crash bar. Add-on or subsequent entries continue to be controlled by the Shift Supervisor and RWP in accordance with plant procedures. Recently, the practice of controlling access to the Containment through the use of the de-energized ACAD electronic lock has been questioned. It has been suggested that this situation may constitute a "Technical Specification High Radiation Area	12/12 Introduced 1/23 Being discussed by RP group 3/20 Tentative Approval	Vogtle

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Occurrence" against the Performance Indicator in that it was a "nonconformance with technical specifications ... applicable to technical specification high radiation areas (>1 rem per hour) that results in loss of radiological control over access...within the respective high-radiation area (>1 rem per hour)." Is this a performance indicator occurrence? **Additional Information** Plant HP customarily places a flashing light at the containment door while entries are in progress as a signal to all personnel that a Containment entry is in progress. This practice is performed in addition to the provisions of Tech Spec 5.7.3. In the situation noted above in the FAQ, a confounding factor occurred in that the flashing light had not been turned on. Although the failure to activate the flashing light is not in accordance with plant procedures, use of the flashing light is not intended to be in lieu of conformance with the Technical Specification 5.7.3, and therefore is not considered material to the issue of performance indicator.		
		Response: As described, the flashing light was intended to warn that a containment entry was in progress. It wasn't provided as a control of the Locked High Radiation Area, per T. S. 5.7.3. Therefore, the failure to energize the light does not result in a performance indicator (PI) hit. The question of whether this situation violated the Technical Specifications (TS) depends on whether the means of locking the area (e.g., de-energizing the ACAD) is consistent with the TS (e.g., keys to the area are administrative controlled by the Shift Supervisor, Radiation Protection Manager (RPM), or their designated alternates). In this case, the "keys" to the area are Security personnel re-energizing the ACAD lock. Therefore, if procedures, or administrative controls (i.e., Standing Orders), are in place that would only allow re-energizing (unlocking) the ACAD for entries that have been authorized (by the Shift Supervisor, RPM, or their designees), the controls meet the intent of the TS and this is not a PI hit. However, if plant procedures, or administrative controls, are not sufficient to prevent unauthorized access (i.e., Security personnel are not required to verify that the individual(s) have the appropriate authorization to enter the high radiation area prior to re-energizing the ACAD), then this would be a violation of the TS and would be a PI hit.		
33.6	OR01	Question: For an at-power containment entry, the containment building outer airlock door is posted as a very high radiation area, with the control point established at the outer airlock door. A procedural violation of a very high radiation area posting occurred, when an operator was stationed in the airlock with the outer airlock door closed and the inner airlock door open. The HP technician outside the outer airlock door was unable to gain access to the airlock under these conditions. This was treated as a violation of a very high radiation area posting due to the HP technician's inability to positively control the activities of the operator in the airlock. However, at no time were any personnel able to gain unauthorized or inadvertent access to areas in which radiation levels could be encountered at the 10CFR20.1602 limits. All areas in containment, potentially exceeding the 10 CFR 20.1602 limits, have additional access controls in place to prevent unauthorized or inadvertent entry (i.e. Reactor Sump is a Very High Radiation Area which is locked and controlled with a separate key, access to the reactor cavity is prevented by removal of the access ladder, movable incore detectors are on a clearance to prevent operation during containment entries, etc.) The question is: Does an access control violation of a very high radiation area posting constitute a "Very High Radiation Area Occurrence" for purposes of reporting the associated NRC Performance Indicator, when there is no possibility of exposure to fields as defined by 10 CFR 20.1602?	1/23 RP group to review 3/20 Tentative Approval	Turkey Point

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response: Questions 34.2, 34.4 and this question are specific variations of the same generic question. The generic question is applicable to situations where the Locked High Radiation Area(s) has been conservatively posted (i.e., at the containment door). The question is "If an individual, who has not fully met the requirements for access to a Locked High Radiation Area (i.e., no HP escort, dosimeter not turned on, etc.), crosses the posted boundary, is this a PI occurrence if additional physical controls were in place (i e., cocooning, locked doors, or flashing lights that meet the T.S. controls) such that they could not access any dose rates greater than 1000 mrem/hr without violating those additional controls?" This situation would not constitute a loss of radiological control over access to or work activities within the respective high radiation areas. Therefore, per the definition in NEI 99-02, this violation would not be a reportable PI occurrence.		
34.1	IE03	Question: In December 2001 the plant identified degradation of the "A" Reactor Feed Pump (RFP) seal. Engineering evaluated the degradation (JENG-01-0701) and provided monitoring guidance that addressed several potential degradation scenarios and specific actions for each. On August 20, 2002 the monitoring guidance was incorporated into an Operations Shift Standing Order (OSSO 01-0007). On October 2, 2002 one of the monitoring criteria was exceeded and the operations staff took the actions specified in OSSO 01-007. The Operating Crew reduced power and took the "A" RFP out of service. When the monitoring criteria was exceeded the plant was at approximately 97% CTP and power was reduced to approximately 48% CTP to support removing the RFP from service. The downpower was performed in accordance with normal plant Operating Procedure OP-65. The following sequence of events has been extracted from the shift log for 10/02/02. 0530 determined increase in input to floor drain sumps due to leakage from "A" RFP seal area (This was documented in a late log entry at 0626) 0600 Logged report of 20 – 60 GPM seal leak on "A" RFP 0600 Performed Shift Turnover 0612 Reset scoop tube of "B" RWR MG set in preparation for downpower 0614 Entered OP-65, Commenced downpower 0619 Lowered power to 85% using RWR "A" and "B" 0623 Lowered power to 75% using RWR "A" and "B" 0630 Lowered power to 69% using RWR "A" and "B" 0642 Inserted first CRAM Group lowered power to 52% IAW OP-65 0705 Removed "A" RFP from service by tripping the pump IAW OP-2A Under definition of Terms NEI 99-02 Rev. 2 states "*Unplanned changes in reactor power* are changes in reactor power that are initiated less than 72 hours following the discovery of an off-normal condition, and that result in, or require a change in power level of greater than 20% of full power to resolve." Under Clarifying Notes NEI 99-02 Rev. 2 states the following: "The 72 hour period between discovery of an off-normal condition and the corresponding change in power level is based on the typical time to assess the plant conditions, and prepare, review, and approve the necessary work orders, procedures, and necessary safety reviews to effect repair. The key element to be used in determining whether a power change should be counted as part of this indicator is the 72 hour period and not the extent of the planning that is performed between the discovery of the condition and the initiation of the power change." "This indicator captures changes in reactor power that are initiated following discovery of an off-normal condition. If a condition is identified that is slowly degrading and the licensee prepares plans to reduce power when the condition reaches a predefined limit, and 72 hours have elapsed since the condition was first identified, the power change does not count. If the situation suddenly degrades beyond the predefined limits and requires rapid response this situation would count."	3/20 Introduced 3/20 Tentative Approval	FitzPatrick

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		This guidance statement contains three specific elements to be considered when determining if the power change counts as an Unplanned Power Change of greater that 20% rated CTP. First, had 72 hours elapsed between the identification of the condition and the reduction in power of greater than 20% of rated CTP? The degrading condition was identified in December 2001 and was monitored for more than 10 months using criteria for action documented in an engineering memorandum and later in an Operations Department standing order. Second, did "the situation suddenly degrade beyond the predefined limits"? The monitoring plan in the engineering memorandum and standing order criteria included the condition observed on 10/02/002. The plan stated "IF flashing occurs at the seals, THEN take the pump off service immediately." The observed condition on 10/02/02 was a significant change in seal leakage, however, it was consistent with a specific criterion in the monitoring plan and the operators executed the actions described in the plan. Third, did the condition "require rapid response"? When the condition exceeded the monitoring criteria the operating crew logged the increase, completed shift turnover, entered a normal operating procedure and reduced power in a measured and deliberate response to the observed condition. Comment: The guidance states that this indicator captures changes in reactor power that are initiated following the discovery of an off-normal condition and as noted above provides criteria for determining when a downpower should be counted. The monitoring plan was in place for 10 months and while there was a significant change in leakage rate there was no rapid response. A rapid response would be one that required the operating crew to take immediate action to manipulate the plant in response to an unexpected event or transient. However, in this case the operating crew observed the increase in leakage, referred to the monitoring plan, assessed the situation against the plan, and determined the appropriate course of action. The operating crew then turned the shift over to the next crew, the oncoming crew briefed on the evolution, and executed a controlled downpower using normal operating procedures. In the view of the plant this deliberate and controlled response in accordance with a documented monitoring plan does not represent a rapid response by the operating crew. While no past FAQs directly address this particular scenario several do address elements of the scenario. **FAQ 6** presented two hypothetical cases one of which concerned RCS unidentified leakage that could be attributed to a degrading recirculation pump seal. The FAQ asked if plans are made to repair or replace the seal if administratively established limits are exceeded and the seal leakage exceeds the administratively set limit days/weeks later would this be counted as an unplanned power change? The response stated, "The cases described would not be counted in the unplanned power changes indicator." In discussing the time between discovery and exceeding an administratively set limit the response stated, "This allowed for assessment of plant conditions, preparation and review in anticipation of an orderly plant shutdown." Comment: The circumstances in the case being submitted for consideration are similar in that the condition was identified, the potential for further degradation was assessed, monitoring criteria and actions were prepared, the condition was monitored for months and when it exceeded an action level an orderly power reduction was made. **FAQ 277** addresses a condition where a hydrogen leak is identified in February 2000 and monitored until December 2000 when leakage increased to a level that the licensee shut down the plant to affect repairs. The FAQ asked in this counted as an unplanned power change. The response stated " No, the degraded condition was identified in February 2000 and an Action		

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		Plan was developed to address the condition, including an outage schedule, work request, material identification, and procurement." The response goes on to say "The increased leak rate in December 2000 was not a different condition, only a continuing degradation of the off-normal condition discovered in February 2000." Comment: Similar, to FAQ 277 the condition in the case being submitted for consideration was identified months before the need to reduce power occurred. In the time between condition identification and power reduction an action plan was put in place, work control documents were planned, and materials necessary to replace the degrading seal were identified and procured. **FAQ 311** addresses another hydrogen leak scenario that included monitoring and more than one contingency for repair. In summary the question asked, if a degraded condition is identified more than 72 hours prior to the initiation of a plant shutdown, then the shutdown is considered a planned shutdown. The condition, necessitating the shutdown of the unit in this case was initially identified 30 days prior to the actual shutdown. The possibility of the need to shutdown for repairs was recognized just days later and limits were established to trigger that action. In addition repair efforts, including shutdown contingency plans, were ongoing throughout that thirty-day period. Does this situation qualify as a "planned" shutdown as suggested by NEI-99-02 FAQ 277? The response stated, "Yes, this was a planned shutdown and did not require a "rapid response." (NEI 99-02 page 20 lines 1-3) Therefore, it does not count as an unplanned power change." Comment: As discussed previously the degraded condition in case being submitted for consideration was identified 10 months in advance of the power reduction, plans were developed, thresholds were established and when those thresholds were exceeded power was reduced using normal operating procedures as required by the monitoring plan. In view of the guidance provided in NEI-99-02 Rev. 2 and the guidance provided by the FAQs should the 10/02/02 downpower count as an unplanned power change?		
		Response: Although the condition was identified greater than 72 hours before the power reduction and a monitoring plan was in place, the condition suddenly degraded beyond the predefined limit, and as specified in the monitoring plan, required rapid action. Therefore, the power change counts toward the indicator.		

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34.2	OR1	Question: There is no disagreement between the NRC site Resident Inspector on this interpretation, however the Resident Inspector requests NRC NRR concurrence. An individual is briefed on the radiological conditions in his work area and travel path with dose rates of 10 mr/hr- 40 mr/hr, that is located in a BWR drywell controlled and posted as a high radiation area greater than 1.0 rem/hr. The individual enters the drywell with his electronic dosimeter (ED) turned off but does not enter any area that is actually greater than 1 rem/hr nor will any of his work activities take him into any area where the actual dose rates are greater than 1 rem/hr. The worker checks his ED within 15 minutes of the entry and finds the ED turned off. He immediately exits the area and contacts Radiation Protection (RP). Does this constitute a PI occurrence? The unit is shutdown for a refuel outage. The drywell is open and is controlled and posted at the main personnel entrance on Elevation 135' as "Locked High Radiation Area". An RP control point, manned 24 hours per day, is situated directly across from the entrance. The RP control point ensures access to the drywell is properly controlled from a radiological perspective. General area dose rates in the drywell range from 10-400 mr/hr. There are five locations in the drywell that have dose rates at 30 cm exceeding 1000 mr/hr. Four of the five areas are marked in the drywell with a flashing light, posting and rope boundary to control worker access to these areas based on scheduled work activities. The fifth spot is located on the 116' elevation that requires personnel to descend a ladder to gain access to it. The spot has two lead blankets around its sides and is posted in accordance with the procedural guidance for control of radiation shielding specified in NRC Regulatory Guide 8.38. With the lead shielding in place, this spot is essentially inaccessible due to the physical geometry of the pipe source and an immediately adjacent wall. There is no scheduled work in the area and it is not a normal travel path to other areas. There are several individuals on a crew working on the 135' elevation in the drywell approximately 10-15 feet inside the personnel entrance at about 110 degrees in a 10 mr/hr-40 mr/hr general area staging lead blankets for installation. The crew had an ALARA briefing and HP brief prior to physically signing the Radiation Work Permit. Prior to this entry the crew was briefed on the current radiological conditions in their work area by the RP control point. The briefing discussed general area dose rates of 10 mr/hr- 40 mr/hr, the exact work location and that the travel path was not going to expose workers to any areas greater than 1 rem/hr. There is one location on 135' elevation at about 280 degrees that is greater than 1000 mr/hr. This spot is marked with a flashing light, posting and rope boundary preventing unauthorized access. The crew had worked at the drywell earlier in the day. For the first entry the crew had obtained an RP briefing, turned on their electronic dosimeters and proceeded to work. The crew broke for lunch and turned off their electronic dosimeters when leaving the RCA. When returning from break one member of the crew entered the drywell without turning his electronic dosimeter on. After about 15 minutes in the area the individual checked his electronic dosimeter and saw that it was turned off and he immediately exited the area. Investigation by the radiation protection technician verified work area dose rates of 10 mR/hr-40 mR/hr, co-workers electronic dosimetry indicated individuals received a maximum of 8 mR and were in a maximum dose rate field of 27 mR/hr.	3/20 Introduced 3/20 Tentative Approval	Peach Bottom

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		Response: Questions 33.6, 34.4 and this question are specific variations of the same generic question. The generic question is applicable to situations where the Locked High Radiation Area(s) has been conservatively posted (i.e., at the containment door). The question is "If an individual, who has not fully met the requirements for access to a Locked High Radiation Area (i.e., no HP escort, dosimeter not turned on, etc.), crosses the posted boundary, is this a PI occurrence if additional physical controls were in place (i.e., cocooning, locked doors, or flashing lights that meet the T.S. controls) such that they could not access any dose rates greater than 1000 mrem/hr without violating those additional controls?" This situation would not constitute a loss of radiological control over access to or work activities within the respective high radiation areas. Therefore, per the definition in NEI 99-02, this violation would not be a reportable PI occurrence.		
34.3	OR1	Question: During a planned crud burst and cleanup at the start of a refueling outage, higher than anticipated dose rates were experienced outside a demineralizer vestibule. General area dose rates (measured at 30 cm) were approximately 3 rem/hr, which exceeds the criteria for a technical specification locked high radiation area (greater than 1 rem/hr). This area was found during post-crud burst surveys. The area was unposted for approximately nine hours. No electronic dosimeter alarms or unanticipated dosimetry anomalies were noted during this time period. No unanticipated dose to personnel was received due to the condition. This was the first refueling outage following steam generator replacement and as a result, a larger crud burst was experienced than in previous outages. This was an anticipated condition, and a plan to control work activities during the period of elevated dose rates was developed. Specific work restrictions in the vicinity of the demineralizer vestibule were not initially established as a part of this plan due to crediting the presence of a labyrinth entrance to the demineralizer vestibule, when no such labyrinth entrance was present, when evaluating anticipated plant conditions following the crud burst. Without the presence of the labyrinth entrance, the demineralizer vestibule would likely have been controlled as a locked high radiation area in anticipation of increased activity during the crud burst. During the crud burst, higher dose rates than anticipated were noted in some areas of the plant. As a result, more extensive surveys were performed in all letdown affected plant areas. It was during these surveys, which were in addition to those required by the shutdown plan, that the technical specification high radiation area was identified by Radiation Protection personnel. Upon discovery, the area was immediately posted and controlled as a locked high radiation area. The guidance provided in FAQ 100 appears to be applicable to this situation. This FAQ was written to address the question that if during performance of routine radiation surveys a Radiation Protection Technician identifies a Technical Specification high radiation area which results from a plant system configuration change made earlier in the shift, does this count against the Occupational Exposure Performance Indicator? The response to this FAQ states that the answer to this question depends on whether the actions taken were timely and appropriate, and whether the change in radiological conditions was anticipated, etc. In general, identifying changes in radiological conditions is an expected outcome of performing systematic and routine radiation surveys. Thus, such occurrences would not typically be counted against the PI. In this specific case, although the general area dose rates in the vicinity of the demineralizer vestibule were higher than anticipated, in part due to incorrectly crediting the presence of a labyrinth entrance to the demineralizer vestibule, it was recognized prior to the evolution that the crud burst would result in higher than normal radiological conditions in the plant. When higher than expected dose rates were noted in some areas of the plant, timely and appropriate actions were taken to identify these conditions in all areas potentially affected, and proper controls were established when conditions warranted. Should this occurrence count against the technical specification high radiation area PI?	3/20 Introduced 3/20 Tentative Approval	DC Cook

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response: No. In this specific case, although the general area dose rates in the vicinity of the demineralizer vestibule were higher than anticipated, it was recognized prior to the evolution that the crud burst would result in higher than normal radiological conditions in the plant. When higher than expected dose rates were noted in some areas of the plant, timely and appropriate actions were taken to identify these conditions in all areas potentially affected, and proper controls were established when conditions warranted, including the demineralizer vestibule. The radiological conditions were identified and appropriate controls were established as a direct result of the additional surveys conducted for that purpose.		
34.4	OR1	Question: During reactor head inspection activities with the reactor head supported on the head stand, temporary shielding blocked access to the actual locked high radiation area (LHRA) under the reactor head. Removal of the temporary shielding would require significant effort such as removal of scaffold hardware. The shielding and scaffold prevented inadvertent entry into the LHRA. However, the posting and barricade (including a flashing red light) for the inaccessible LHRA under the reactor head was conservatively posted where the radiation levels were less than 1 rem per hour. Several radiation workers were observed breaking the plane of the posted LHRA with portion of their whole body (upper arms and head) as they reached for equipment stored on top of the reactor head platform. The reactor head platform and surrounding areas were monitored remotely by Health Physics Technicians who were in contact with technicians located near the posted areas. A Quality Inspector observing the workers instructed them to move away from the posted area. At the same time, the remote coverage technician notified to local technician to remove the workers from the posted area. Does this count as an occurrence against the technical specification LHRA Performance Indicator?	3/20 Introduced 3/20 Tentative Approval	St Lucie
		Response Questions 33.6, 34.2, and this question are specific variations of the same generic question. The generic question is applicable to situations where the Locked High Radiation Area(s) has been conservatively posted (i.e., at the containment door). The question is "If an individual, who has not fully met the requirements for access to a Locked High Radiation Area (i.e., no HP escort, dosimeter not turned on, etc.), crosses the posted boundary, is this a PI occurrence if additional physical controls were in place (i.e., cocooning, locked doors, or flashing lights that meet the T.S. controls) such that they could not access any dose rates greater than 1000 mrem/hr without violating those additional controls?" This situation would not constitute a loss of radiological control over access to or work activities within the respective high radiation areas. Therefore, per the definition in NEI 99-02, this violation would not be a reportable PI occurrence.		

Temp No.	PI	Question/Response	Status	Plant/ Co.
34.5	MS03	Question: During post maintenance testing on an auxiliary feed water pump, the flow through the pump recirculation line was noted to be lower than allowed by the test procedure (but within pump manufacturer requirements). An investigation revealed that a flow orifice in the recirculation line was partially plugged. A sample of the material recovered from the orifice was analyzed and found to be corrosion products, most likely from carbon steel vents within the pump's isolation boundary. When the pump and associated piping were drained to perform the maintenance, corrosion products were probably introduced into the pump or pump piping. Upon completion of the maintenance, the corrosion products were swept into the orifice in the recirculation line when the pump was started as part of post maintenance testing. The normal suction path for Aux. Feedwater is the Condensate Storage Tanks (CSTs). It is also the normal suction path when conducting surveillance testing. The alternate water supply is safety-related service water (lake). A determination is being made as to whether the orifices would plug from suspended material in the service water supply to the extent that it would render the train incapable of performing its safety function during an operational event. NEI 99-02 page 33 lines 8-23 indicates that equipment failures due to design deficiencies should be evaluated for inclusion if the failure is capable of being discovered during surveillance testing but should be evaluated under the NRC's Significance Determination Process if the failure was not capable of being discovered during normal surveillance test. Question: If the Aux. Feedwater recirculation line flow orifice sizing is characterized as a design deficiency, should the associated fault exposure hours be calculated or should the deficiency be evaluated through the SDP?	3/20 Introduced 3/20 Tentative Approval	Point Beach
		Response: If it is determined that only the time of the failure's discovery is known with certainty (T/2 fault exposure hours), the T/2 fault exposure hours need only be reported in the comment section of the PI data file and need not be included in the calculation of safety system unavailability, and the NRC inspection process would assess the significance of the deficiency. However, if the failure's time of occurrence and time of discovery are known, then the fault exposure hours (if any) would be included in the PI calculation. NRC Inspection Manual Chapter 0305 addresses the topic where an issue may simultaneously cross a PI threshold and also generate a safety significant inspection finding. If the issue has the same underlying cause, it is not "double-counted" in the assessment program. The most conservative significance characterization would be used to determine NRC response.		

DRAFT

Temp No.	PI	Question/Response	Status	Plant/ Co.
34.6	IE02	Question: 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 13 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. (Review of the event has shown that the perceived urgency to slow the turbine was unnecessary.) 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. Since the reason for the decision to break condenser vacuum was the perceived need to protect the main turbine from further damage, and vacuum could have been restored using plant operating procedures, should this be counted as an Unplanned Scram With Loss Of Normal Heat Removal. Response: The ROP working group is currently working to prepare a response.	3/20 Introduced 3/20 Discussed	STP

HOUGHTON, Tom

Subject: Surry MSPI FAQ

Surry MSPI FAQ - Scope of PRA Model

Question:

Should internal flooding initiating events be included in the scope of the PRA used for the MSPI calculations?

Background. The current MSPI guidance (Appendix F) defines the scope of the PRA model used for the MSPI calculations as "internal events." Internal flooding constitutes approximately 2/3rds of the total CDF at Surry. The Surry PRA model used for the MSPI calculations includes internal flooding initiating events. The NRC indicates in the TI report for Surry that internal flooding is an external event that should not be included in the MSPI scope per the NEI guidance. The Licensee believes based on GL 88-20 that internal flooding is an internal initiating event and should be included in the MSPI scope. The licensee notes that inclusion of internal flooding in the MSPI calculations does not mask the other internal initiating event delta CDF contributions since all the initiating event contributions are additive, as long as the accident sequence truncation limit is low enough to capture the contributions from all the significant initiating events. The accident sequence truncation limited used for the Surry MSPI calculations was 1E-12 per year.

Proposed Answer:

Internal flooding initiating events should be included in the scope of internal initiating events for the MSPI calculations.