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| 27.3 | IE02 | Question:<br>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<br>Background Information:<br>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."<br><br>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).<br><br>Verify the following:<br>TDRFP M/A XFER (Manual/Automatic Controller) station is reset to Minimum<br>No TDRFP trip signals are present<br>Depress TDRFP Turbine RESET pushbutton and observe the following<br>Turbine RESET light Illuminates<br>TDRFP High Pressure and Low Pressure Stop Valves OPEN<br>PUSH M/A increase pushbutton on the Manual/Automatic Controller station<br>Should this be considered a scram with the loss of normal heat removal?<br><br>Proposed Answer:<br>The ROP working group is currently working to prepare a response. | 1/25 Introduced<br>2/28 NRC to discuss with resident<br>4/25 Discussed<br>5/22 On hold<br>6/12 Discussed. Related FAQ 30.8<br>9/26 Discussed<br>10/31 Discussed | LaSalle |
| 28.3 | IE02 | Question:<br>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.<br><br>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 | 3/21 Discussed<br>4/25 Discussed<br>5/22 Modified to reflect discussion of 4/25, On Hold<br>6/12 Discussed. Related FAQ 30.8 | Perry |

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| | | coincident with the scram, and it was not immediately apparent what had caused the trip due to the rapid sequence of events.<br><br>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.<br><br>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.<br><br>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?<br><br>Response:<br>The ROP working group is currently working to prepare a response. | | |
| 30.8 | IE02 | Question:<br>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?<br><br>Response:<br>The ROP working group is currently working to prepare a response. | 5/22 Introduced<br>6/12 Discussed<br>9/26 Discussed.<br>10/31 Discussed | Generic |
| 32.3a | IE02 | Question:<br>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 | 1/23 Revised. Split into two FAQs<br>3/20 Discussed<br>5/1 Discussed<br>5/22 Tentative Approval | DC Cook |

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| | | 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.<br>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.<br>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.<br>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.<br>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 | 6/18 Discussion deferred to July<br>7/24 Discussed | |

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| | | 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.<br>Should the reactor trip described above be counted in the Unplanned Scrams with Loss of Normal Heat Removal Performance Indicator?<br>Response:<br>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.<br>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:<br>Should the following event be counted as a scram with loss of normal heat removal?<br>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.<br>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. | 3/20 Introduced<br>3/20 Discussed<br>6/18 Discussed; Question to be revised to reflect discussion<br>7/24 Discussed | STP |

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| | | 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.<br>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*".<br>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.<br>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 broken sooner is because in most cases it is needed to support chemistry testing.<br><br>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 | | |

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| | | 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.<br>Response:<br>The ROP working group is currently working to prepare a response.<br>Licensee Proposed Response:<br>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. | | |
| 35.7 | EP03 | Question:<br>Can the licensee modify the ANS testing methodology when calculating the site value for this indicator?<br>Response:<br>Yes. Page 95 line 19-23 of NEI 99-02 will be modified as follows:<br>~~*The testing of the public alert and notification system shall meet the requirements of the licensee's FEMA approved Alert and Notification System (ANS) design report and supporting FEMA approval letter.*~~ *Changes to the activation and/or testing methodology* ~~*shall receive FEMA approval prior to implementation and shall be noted in the licensee's quarterly PI report in the comment section*~~ Siren systems may be designed with equipment redundancy, *multiple signals* or feedback capability. It may be possible for sirens to be activated from multiple control stations *or signals*. If the use of redundant control stations *or multiple signals* is in approved procedures and is part of the actual system activation process, then activation from either control station *or any signal* should be considered a success.<br>Note: If prior to this FAQ response, a plant changed their testing methodology, ~~without prior FEMA approval,~~ it is not necessary to recalculate their past PI data from the time of the change. ~~; so long as they subsequently obtain FEMA approval~~. However, those plants still need to update the affected PI data report by noting the change in the comment section. | 8/21 Introduced<br>9/25 Tentative Approval. The response will be modified to state that the methodology may be changed once a 50.54 (q) has been completed and a letter sent to FEMA requesting the change.<br>10/23 Modification proposed 9/25 deleted. Tentative Approval<br>12/4 Discussed revised wording. Awaiting discussion with FEMA. | Generic |
| 35.8 | MS03 | Question:<br>NEI 99-02 states that Planned Unavailable Hours include testing, unless the "function can be promptly restored ... by an operator in the control room". The guideline further states that "restoration actions must be contained in a written procedure, must be uncomplicated (a single action or a few simple actions), and must not require diagnosis or repair". "The intent ... is to allow licensees to take credit for restoration actions that are virtually certain to be successful (i.e., probability nearly equal to 1) during accident conditions".<br>In the following scenario, a motor driven auxiliary feed pump with an auto start feature is placed in "pull-to-lock" for performance of a calibration procedure on the recirculation valve flow transmitter. Only the positioning of the pump's control switch affected its availability.<br>A licensed reactor operator in the control room was briefed on the manual pump restoration task. The pre-evolution briefing to restore this pump to automatic status was completed by the Senior Reactor Operator. The "balance of plant" reactor operator was designated as the owner of this task. All crew members were briefed of the need to return the pump to automatic control. This action is uncomplicated in that it is a single action (i.e. remove the pump from | 9/25 Introduced<br>10/23 Discussed<br>12/4 Discussed. Question being revised.<br>1/22 Tentative Approval | Beaver Valley |

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| | | pull-to-lock) and does not require diagnosis.<br>Restoration actions are contained within three different procedures. The Precautions and Limitations section of the calibration procedure for the recirculation valve flow transmitter is being revised to state that "the Control Room Operator shall be briefed and assigned responsibility for restoring the pump (i.e. removing from pull-to-lock) to automatic control if the pump is needed to perform it's safety function". directs the performer to inform the control room operator to align the control switch for the auxiliary feed pump in accordance with its "normal system arrangement" per the current plant conditions. The conduct of operations procedure, which governs operator performance at all times, specifies "anytime valid plant conditions indicate a need for...Safety System actuation, and the actuation fails to automatically occur, the operator is required to manually initiate the protective action". That is, if there is a need for the auxiliary feedwater pump to start, the operator is to manually ensure a pump start is satisfied by taking the switch out of pull to lock. Simulator training is used to re-enforce this expectation. Finally, this pump is only required to operate during an event requiring use of the Emergency Operating Procedures and instructions are contained within this network to direct the operator to verify and/or initiate pump operation.<br>In this example, can the manual operator action be credited in place of the automatic pump start function for continued pump availability?<br>Response:<br>The actions described satisfy the criteria of NEI 99-02, Rev. 2 for considering the Auxiliary Feed Pump available. | | |
| 36.1 | IE02 | Question:<br>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).<br>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.<br>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.<br>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 | 9/25 Introduced and discussed | Quad Cities |

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| | | 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.<br>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.<br>Does this scram constitute a scram with a loss of normal heat removal?<br><br>Response:<br>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.<br>Further supporting information:<br>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.<br>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:<br>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?<br><u>Description of Event:</u><br>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.<br>At approximately 1356 hours, the crew received a High Area Temperature alarm for the Main | 9/25 Introduced and discussed | Peach Bottom |

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| | | 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.<br>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.<br><br>**Problem Assessment:**<br>It is recognized that loss of Reactor Building ventilation results in rising temperatures in the Outboard MSIV Room. The rate of this temperature rise and the maximum temperature attained are exacerbated by summertime temperature conditions. When the high temperature isolation occurred, the crew immediately recognized and understood the cause to be the loss of Reactor Building ventilation. The crew then prioritized their activities and utilized existing General Plant (GP) and System Operating (SO) procedures to re-open the MSIVs.<br>Reopening of the MSIVs was:<br>• easily facilitated by restarting Reactor Building ventilation,<br>• completed from the control room using normal operating procedures<br>• without the need of diagnosis or repair<br>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.<br><u>Discussion of specific aspects of the event:</u><br>Was the recognition of the condition from the Control Room?<br>▪ 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.<br>Does it require diagnosis or was it an alarm?<br>▪ The event is annunciated in the control room as described previously.<br><br>Is it a design issue?<br>▪ 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 | | |

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| | | temperatures, which input into the Group I isolation signal, are higher on Unit 2 than Unit 3.<br>Are actions virtually certain to be successful?<br>▪ 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.<br>Are operator actions proceduralized?<br>▪ 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.<br>How does Training address operator actions?<br>▪ The actions necessary for responding to a Group I isolation and subsequent recovery of the Main Steam system are covered in licensed operator training.<br>Are stressful or chaotic conditions during or following an accident expected to be present?<br>• 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:<br>The Peach Bottom Unit 2 July 22, 2003 reactor scram followed by a high area temperature Group I isolation should not be included in the Performance Indicator - "Unplanned Scram with a Loss of Normal Heat Removal." This specific MSIV closure does not meet the definition of "Loss of normal heat removal path" provided in NEI 99-02, Rev. 2, page 15, line 37, in that the main steam system was "easily recovered from the control room without the need for diagnosis or repair. Therefore, it would not be appropriate to include this event in the associated performance indicator – Unplanned Scrams with Loss of Normal Heat Removal. | | |
| 36.5 | OR1 | Question:<br>Two individuals enter an area of containment, previously surveyed and posted as a radiation area. They comply with all applicable RWPs and procedures. Additionally, they are continuously, remotely monitored by teledosimetry (Electronic Personnel Dosimeter, EPD). During the entry, their EPDs alarm on dose rate, which had been preset to alarm at 150 mrem/hr. The individuals detect the alarm and immediately exit the area to notify HP. Concurrently, HP technicians manning the Central Alarm Station detect the alarm condition and dispatch a nearby roving HP technician to the area to confirm the alarm and verify worker protection. The area is immediately surveyed by HP and found to contain dose rates of approximately 2 rem/hr at 12 inches; the area is reposted as a Locked High Radiation Area (LHRA). Investigation of the event reveals that the area entered contains a length of piping and a valve through which the reactor cavity is filled and drained. Shortly before this entry, the reactor cavity had been filled via this pipe. The specific area's dose rate had been confirmed by past experience to be unaffected by cavity filling and therefore was not flagged for resurvey following the fill evolution. It is hypothesized that a hot particle dislodged from an upstream location during filling and migrated into the vicinity of the work location prior to the worker's entry. The same area had been occupied numerous times after the last survey, before filling, | 1/22 Introduced | Vogtle |

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| | | with no problems. Should this be counted as a performance indicator event?<br><br>Furthermore, should any event be counted against this PI in which an entry into an area occurs where the dose rate increased (to greater than 1 rem/hr) in a reasonably unanticipated manner?<br><br>Response:<br>This is not a PI occurrence for either instance questioned above, particularly for a case where the area has been specifically considered for a possible dose rate increase. However, instances where the potential dose rate change is not considered and should have been, would be a PI event. Additionally, the unanticipated dose criteria would still apply. | | |
| 36.6 | IE03 | Question:<br>NEI 99-02 states that anticipatory power reductions intended to reduce the impact of external events such as hurricanes or range fires threatening offsite power lines are excluded.<br><br>On September 20, 2003, Salem 1 and 2 were manually shutdown due to switchyard arcing from salt buildup on insulators in the switchyard. The salt buildup was due to unusual meteorological conditions (hurricane force winds, with minimal rain). These conditions led to an abnormal buildup of salt from the Delaware River to be deposited on the insulators. The shutdowns were not conducted in response to any existing or immediate equipment problems. The shutdowns were initiated to address the impact of an external event, that manifested itself in an unexpected manner and to alleviate nuclear plant safety concerns arising from an external event outside the control of the plant.<br><br>Should these shutdowns be counted as unplanned power reductions?<br><br>Response:<br>No. These power reductions are considered to be anticipatory because they were taken prior to any equipment failures or electrical system protective actuations at Salem 1 or 2, were caused by an unusual meteorological condition, and were taken to alleviate nuclear plant safety concerns arising from an external event outside the control of the plant. | 1/22 Introduced | Salem |
| 36.7 | MS01-04 | Question (Appendix D):<br>**Proposed Overhaul Exemption for Unavailability Hours Incurred On Unit 2 Safety Systems Due To Planned Overhaul of Unit 1 Nuclear Service Water System (NSWS) Pump**<br>Catawba Nuclear Station (CNS) refurbished the 1B Nuclear Service Water System (NSWS) pump during a recent refueling outage. Unit 1 was defueled and Unit 2 at power operation during this activity. Technical Specifications provided for an allowable outage time sufficient to accommodate the overhaul hours associated with the pump replacement. Catawba has a shared NSWS between both units such that the 'B' train pumps for both units (1B and 2B NSWS pumps) share a common intake pit and discharge header. Removing and reinstalling 1B NSWS pump for refurbishment rendered 2B NSWS pump unavailable.<br>Removal of the 1B NSWS pump required making the 2B NSWS pump inoperable for 2.6 hours in order to disconnect a submerged support and inspect the nuclear service water pond intake. Once the 1B NSWS pump was removed from the pit, the 2B NSWS pump was restored to operable status and Unit 2 safety systems were restored to fully operable status. After the 1B | 1/22 Introduced | Catawba |

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| | | NSWS pump refurbishment was complete, the 2B NSWS pump was again rendered inoperable for reinstallation of the 1B NSWS pump. The reinstallation was originally scheduled for 20 hours but took longer due to complications. Catawba is seeking to exclude the unavailability that was incurred from the actual 2.6 hours required to remove the pump and the 20 hours originally scheduled for reinstallation (22.6 hours total).<br>Although the NSWS is not a monitored system under NEI 99-02 guidance, its unavailability does affect various systems and components, many of which are considered major components by the definition contained in FAQ 219 (diesel engines, heat exchangers, and pumps). The specific performance indicators affected by unavailability of the NSWS are Emergency AC, High Pressure Safety Injection, Residual Heat Removal, and Auxiliary Feedwater. If the requested hours for this overhaul of the 1B NSWS pump cannot be excluded it would result in 22.6 hours unavailability on 'B' train of each of the four monitored systems.<br>NEI 99-02 states that "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." The following information is provided iaw the NEI guidance.<br>QUANTITATIVE RISK ASSESSMENT<br>Duke Power has used a risk-informed approach to determine the risk significance of taking the 'B' loop of NSWS out of service for up to 22.6 hours within its current technical specification limit of 72 hours. The acceptance guidelines given in the EPRI PSA Applications Guide were used to determine the significance of the short-term risk increase from the outage. The NSWS outage did not create any new core damage sequences not currently evaluated by the existing PRA model. The resulting Incremental Conditional Core Damage Probability (ICCDP) was 1.2E-06, a low-to-moderate increase in the CDF, and was acceptable based on consideration of the non-quantifiable factors involved in the contingency measures that were implemented during the overhaul. Based on the expected increase in overall system reliability of the NSWS, an overall increase in the safety of both Catawba units is expected.<br>Contingency measures during the overhaul included Component Cooling Water System cross train alignment which allowed the "A" train to supply cooling to the High Pressure Injection and Auxiliary Feedwater pump motor coolers during the "B" train work. The RN pipe inspection evolution also included the following protective measures:<br><br>• "A" train EDGs were protected throughout the evolution.<br>• The Unit 2 transformer yard was protected throughout the evolution.<br>• The "A" train equipment supported by RN was protected.<br>• No maintenance or testing on operable offsite power sources.<br>• All testing and maintenance on the operable train rescheduled to other time periods.<br>• No work or testing that could affect the SSF or SSF Diesel Generator.<br>• No work or testing that could affect the Turbine-Driven AFW Pump on Unit 2. | | |

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| | | EXPECTED IMPROVEMENT IN PLANT PERFORMANCE<br>The NSWS pumps are refurbished on a specified interval to assure continued, reliable operation. The NSWS pump refurbishment is expected to increase overall system reliability.<br>NET CHANGE IN RISK AS A RESULT OF THE OVERHAUL ACTIVITY<br>Increased NSWS train unavailability as a result of this overhaul did involve an increase in the probability or consequences of an accident previously evaluated during the time frame the NSWS header was out of service for pump refurbishment. Considering the small time frame of the 'B' NSWS train outage with the expected increase in reliability, expected decrease in future NSWS unavailability as a result of the overhaul, and the contingency measures that were utilized during the overhaul, net change in risk as a result of the overhaul activity is reduced. | | |
| | | Response:<br>For this plant specific situation, planned overhaul hours for the nuclear service water support system may be excluded from the computation of monitored system unavailability. Such exemptions may be granted on a case-by-case basis. Factors considered for this approval include (1) the results of a quantitative risk assessment of the overhaul activity, (2) the expected improvement in plant performance as a result of the overhaul, and (3) the net change in risk as a result of the overhaul. | | |
| 36.8 | IE02 | Question:<br>On August 14, 2003 Ginna Station scrammed due to the wide spread grid disturbance in the Northeast United States. Subsequent to the scram, Main Feedwater Isolation occurred as designed on low Tavg coincident with a reactor trip. However, due to voltage swings from the grid disturbance, instrument variations caused the Advanced Digital Feedwater Control System (ADFCS) to transfer to manual control. This transfer overrode the isolation signal causing the Main Feedwater Regulation Valves (MFRVs) to go to, and remain at, the normal or nominal automatic demand position at the time of the transfer, resulting in an unnecessary feedwater addition. The feedwater addition was terminated when the MFRVs closed on the high-high steam generator level (85%) signal. Operators conservatively closed the MSIVs in accordance with the procedure to mitigate a high water level condition in the Steam Generators. Decay heat was subsequently removed using the Atmospheric Relief Valves (ARVs). Should the scram be counted under the PI "Unplanned Scrams with Loss of Normal Heat Removal?" | 1/22 Introduced | Ginna |
| | | Response:<br>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 | | |

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| | | 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).<br><br>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. | | |
| 36.9 | IE02 | Question:<br>During startup activities following a refueling outage on Millstone Unit 2 new monoblock turbine rotors were installed in the LP turbines, reactor power was approximately 10% of rated thermal power, feedwater was being supplied to the steam generators by the turbine driven main feedwater pumps, the main condensers were in service, and the main turbine was being started up in preparation for plant startup. 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 began to increase 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. The atmospheric dump valves operated automatically to control reactor coolant system temperature, by removing core decay heat and reactor coolant pump heat. The core decay heat load was very low during this event due to the length of the refueling outage and the fact that approximately one-third of the fuel assemblies in the core had been replaced.<br><br>Does a SCRAM in which the normal heat removal path is manually isolated in accordance with plant procedures for protection of non-safety plant equipment count against this indicator?<br><br>Response: | 1/22 Introduced | Millstone 2 |
| *37.1* | *OR1* | *Question:*<br>*Would the following example be considered a Performance Indicator Hit to the Occupational Cornerstone?*<br>*A large check valve was required to be physically cut from the safety injection system. When the valve was cut out of the system and lowered to its resting place, the dose rates on the open pipe ends of the system were 5-rem/hr at the plane of the pipe and 1.5-rem/hr at 30-centimeters from the pipe. The open pipe was approximately 8-feet in the overhead and could only be accessed via scaffolding; and the scaffolding had been disassembled to lower the check valve into its resting place. This task was completed on night shift just prior turnover. The entrance to the Steam Generator Bay, where this valve was located, was posted as a Technical Specification Locked High Radiation Area (LHRA). The posting was on both the wire cage door, and hung* | *2/19 Introduced* | *Ft. Calhoun* |

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| | | *from magnets on the door jam. An on-coming RP Technician came to the work area to obtain a turnover from the night shift RP Technician. This area was also under camera surveillance both inside and outside the Steam Generator Bay; however, no technician was assigned coverage responsibilities at the camera station during turnover. During the turnover, the off going and on coming RP Technicians decided to enter the bay to view the condition of the recently completed task. The RP technicians went into the bay approximately three feet past the entrance, leaving the door open and the entrance rope posting down to discuss radiological conditions associated with the task (e.g., the door was open unposted and not clearly guarded). The RP Technicians did not complete a required LHRA briefing to ensure administrative controls for the LHRA access were established The technicians did not have line of sight of the established LRHA boundary, but were physically between the entrance to the LHRA and the actual areas where dose rates were greater the 1 rem/hr (i.e., open pipe ends and Steam Generator Man ways). The RP Technicians indicated that they would have stopped any personnel from entering the area and had no intention of proceeding further into the Steam Generator Bay area. There was no intention on the part of the RP Technicians to leave the door unlooked. The door being left unlocked and the posting removed was an unintended human error.* | | |
| | | *Response:*<br>*This event should not be counted as a performance indicator event since fully qualified RP-Technicians (meeting ANSI 18.1 requirements) were physically between the sources of radiation (≥ 1,000 mrem/hr) and the entrance to the Steam Generator cubical. These technicians were authorized under the appropriate radiation work permit and were capable of warning individuals that any attempted entry is unauthorized, and able to alert proper authorities (via radio) of the improper entry attempt. While the posting was down the area was constantly attended by these RP-Technicians and they would have prevented unauthorized individuals from being exposed to radioactive material in excess of Part 20 limits.*<br>*The station does not use standard technical specification and has conservatively designated this event as a violation of the stations technical specifications* | | |
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