ID 356

Posting Date 12/04/2003

Question NEI 99-02, revision 2 refers to the "NEI performance indicator Website (PIWeb)" on page 3 (line 6), page 5 (line 21), and page B-1 (line 5). Specifically, these sections describe the role of PIWeb in the collection of data and the development of quarterly NRC data files and change files. With the implementation of Consolidated Data Entry (CDE), is it acceptable to use CDE to accomplish these functions?

Response Yes. CDE has been demonstrated to accurately collect the ROP data and generate the associated quarterly NRC data files and change files

All All

ID 245

Posting Date 01/10/2001

Question How does uncertain data resulting from missing information or lack of credible information (i.e., willful acts) impact current and past PI data reporting?

Response The past or current data must be revised when the correct information is determined, regardless of the cause.

ID 217

Posting Date 10/01/2000

Question FAQ 170 discusses correcting past unavailability hours for Emergency AC System surveillance testing which were found to be incorrectly reported to WANO. The FAQ response states that historical data does not have to be revised, except to ensure that the data is accurate back to the first quarter of 2000. Can this response be applied to any correction of performance indicator data that occurred in the historical (prior to first quarter of 2000) data time period?

Response Data in the historical submittal (through the end of 1999) does not require correction. However, data may be revised by the licensee if desired and as described and allowed by NEI 99-02.

Initiating Events

IE01 Unplanned Scrams

ID 402

Posting Date 08/18/2005

Question On December31, 2004, during Oconee Unit 3 startup, there was an unanticipated change in reactor power from about 3% to 6%. The control room operator was initiating a power increase to 15% to enable putting the turbine online. When the desired power level value was input into the integrated control system (ICS), without awaiting a rate input or the operator placing ICS in Auto, the system unexpectedly started rapidly raising reactor power at the maximum rate. The control room team quickly took action to mitigate the power excursion by reducing the ICS power demand setpoint. The regulating rod group was inserted at normal rod speed by the ICS as it responded to the new demand. Due to normal control system overshoot, the control rods were inserted sufficiently to place the reactor in a shutdown condition. The reason for the unexpected action by the ICS was due to a software error that was introduced during an update to the system during the refueling outage. Upon completion of the transient mitigation response, the control room team decided to complete the reactor shutdown via manual control rod insertion of the remaining rod groups in the normal sequence. The event resulted in a subcritical reactor with power range NIs reading zero due to rod motion properly requested from the ICS in response to operator mitigation of the initial transient and minor power excursion. The definition of "scram" as applied to the initiating events PI IE01 Unplanned Scrams is a rapid insertion of negative reactivity that shuts down the reactor (e.g. via rods, boron, opening trip breakers, etc.) A conservative reading of the definition results in the event meeting the definition of "Unplanned Scram" for the purpose of NRC PIs. However, it is unclear whether normal rod motion at ONS is considered "rapid".

Question: Is the reactor shutdown described above considered a scram for performance indicator reporting?

Response No. Rod insertion by the integrated control system at normal speed is not considered a "rapid addition of negative reactivity."

ID 382

Posting Date 04/28/2005

Question On November 22, 2003, Salem 2 initiated a reactor startup at 2210 following refueling. The reactor was declared critical at 0106 on November 23, 2003. At 0226, low power physics testing began. Based on a review of information from the plant computer, the reactor was subcritical prior to this event. With low power physics testing continuing, a control rod dropped into the reactor core, causing the subcritical reactor to become more subcritical. At 0507, the Operating crew entered the abnormal procedure for a dropped control rod. Based on the reactor being in a subcritical condition, the abnormal procedure directs all rods to be inserted. The procedure does not require all rods to be inserted if the reactor remains critical. At 0519, following a crew brief, the reactor was manually tripped per procedure as directed by the Control Room Supervisor.

NRC POSITION

The NRC resident office has indicated that an unplanned scram should be counted for this event. The inspectors believe that the appropriate guidance in NEI 99-02, Revision 2, which should be followed begins on line 39 of page 12. This guidance states that the types of scrams that should be included are: Scrams that resulted from unplanned transients, equipment failures, spurious signals, human error, or those directed by abnormal, emergency, or annunciator response procedures.

BASIS FOR NRC POSITION

The inspectors considered that for the conduct of physics testing, the reactor was maintained critical or if subcritical, very near critical. In fact the main control room logs did not distinguish otherwise and only included a log entry stating that the reactor was critical. The inspectors also considered that many transients may actually render the reactor subcritical before the resultant scram is inserted. It is the intent of this PI to count all unplanned transients that begin while the reactor is critical and result in an unplanned reactor scram. The November 23, 2003, manual reactor trip was immediately preceded by plant conditions that maintained the reactor very near critical or critical.

PSEG POSITION

This was not reported as an Unplanned Scram in November 2003 because the scram occurred while the reactor was subcritical. A review of the post-trip review and notification documentation indicate that both the Operations Superintendent and the Control Room Supervisor were aware of the fact that the reactor was subcritical prior to the trip and that there was a procedural requirement to insert all rods if the reactor was subcritical as a result of

the dropped rod. Tripping the reactor is a conservative method to insert the rods.

BASIS FOR PSEG POSITION

PSEG utilized the following guidance from Section 2.1, Initiating Events Cornerstone, of NEI 99-02 to determine that the subcritical scram should not be counted:

- Page 11, Lines 24 26, Indicator Definition is the number of unplanned scrams during the previous four quarters, both manual and automatic, while critical per 7000 hours.
- Page 11, Lines 28 31, Data Reporting Elements, instruct licensees to report the number of unplanned automatic and manual scrams while critical in the previous quarter
- Page 12, Lines 1 4, Calculation, demonstrates that the value for this PI is derived by multiplying the total unplanned scrams while critical in the previous 4 quarters by 7000 hours and dividing the result by the total number of hours critical in the previous 4 quarters
- Page 12, Lines 16 17, defines criticality as existing when a licensed operator declares the reactor critical. The scram in question occurred after the reactor was verified to be subcritical.
- Page 12, Lines 17 19, states that there may be instances where a transient initiates from a subcritical condition and is terminated by a scram after the reactor is critical and that these conditions count as a scram. The guidance specifically requires that the reactor must be critical at the time of the scram. The relevant condition is to determine if the reactor is critical at the time of the scram and, if so, is reportable under this PI.
- Page 12, Line 30 states that dropped rods are not considered reactor scrams.
- Page 13, Lines 4 and 9 state that an example of a scram that is not included in this PI is Reactor Protection System actuation signals that occur while the reactor is subcritical.

Should this event be counted as an Unplanned Scram?

Response No. This event does not need to be counted as an Unplanned Scram. This PI counts the number of scrams while critical. During this event, operators tripped the reactor after determining the reactor was subcritical.

ID 354

Posting Date 09/25/2003

Question Several units scrammed as a result of the major grid disturbance and blackout this summer. Are they required to count this external event caused scram in the IE01 performance indicator?

Response Yes, there is no exemption from counting these scrams under IE01, Unplanned scrams. Note, however, that they are not counted under IE02, Scrams with loss of normal heat removal, because there is a specific exemption from counting loss of offsite power.

ID 275

Posting Date 05/31/2001

Question A plant is reducing power for a planned refueling outage, and is planning to insert a manual scram at 25 percent power in accordance with the plant shutdown procedure. At 28 percent power, as a result of a report from the field, operators believe they are about to have an equipment failure that would lead to an automatic scram. The operators immediately insert a manual scram. Afterwards, the operators determine that the actual field condition was minor, and the suspected equipment failure would not have occurred. Therefore, there would not have been an automatic scram. Should the manual scram be counted as an unplanned scram?

Response Yes, the manual scram should be counted because the scram was inserted above the 25% level specified in the plant shutdown procedure.

ID 159

Posting Date 04/01/2000

Question With the Unit in Operational Condition 2 (Startup) a shutdown was ordered due to an insufficient number of operable Intermediate Range Monitors (IRM). The reactor was critical at 0% power. "B" and "D" IRM detectors failed, and a plant shutdown was ordered. The manual scram was inserted in accordance with the normal shutdown procedure. Should this count as an unplanned reactor scram?

Response No. If part of a normal shutdown, (plant was following normal shut down procedure) the scram would not count.

ID 5

Posting Date 11/11/1999

Question The Clarifying Notes for the Unplanned Scrams per 7000hrs PI state that scrams that are included are: scrams "that resulted from unplanned transients...." and a "scram that is initiated to avoid exceeding a technical specification action statement time limit;" and, scrams that are not included are "scrams that are part of a normal planned operation or evolution" and, scrams "that occur as part of the normal sequence of a planned shutdown..." If a licensee enters an LCO requiring the plant to be in Mode 2 within 7 hours, applies a standing operational procedure for assuring the LCO is met, and a manual scram is executed in accordance with that procedure, is this event counted as an unplanned scram?

Response If the plant shutdown to comply with the Technical Specification LCO, was conducted in accordance with the normal plant shutdown procedure, which includes a manual scram to complete the shutdown, the scram would not be counted as an unplanned scram. However, the power reduction would be counted as an unplanned transient (assuming the shutdown resulted in a power change greater than 20%).However, if the actions to meet the Technical Specification LCO required a manual scram outside of the normal plant shutdown procedure, then the scram would be counted as an unplanned scram.

Initiating Events

IE01, IE03 Initiating Events

ID 296

Posting Date 12/13/2001

Question As a result of a stator cooling water leak, power was reduced to remove the main turbine from service. When the main turbine was tripped, a loss of condenser vacuum occurred which necessitated a plant scram. The loss of vacuum was caused by inadequate torque on a moisture separator/reheater manway, which resulted in significant air in-leakage when the pressure in the tank relaxed as a result of taking the turbine off line. The NRC resident inspector office has indicated the appropriate NEI 99-02 guidance that should be followed is a paragraph (starting on line 8 of page 17, NEI 99-02, Revision 1) discussing when an unplanned off-normal condition occurs during a planned power change. The paragraph discusses when the unplanned condition should be counted as an unplanned power change because it is outside or beyond the scope of the planned power change. The NRC interpretation is that both an unplanned power reduction and an unplanned scram should be counted for such an event. Our position is that another paragraph of NEI 99-02 applies (starting on line 6 of page 18), which says that off-normal conditions that begin with one or more power reductions and end with an unplanned reactor trip are counted in the unplanned reactor scram indicator only. Should this event be counted only as an unplanned scram because the power reduction and the scram were related, or should it be counted as both an unplanned power reduction and an unplanned scram?

Response There should be a count for both indicators because the cause of each occurrence was different. The unplanned power change was initiated in response to the stator cooling water leak and the scram was initiated due to loss of vacuum.

Initiating Events

IE01-IE02 Initiating Events

ID 255

Posting Date 02/08/2001

Question **Appendix D - Diablo Canyon Units 1 and 2**

At Diablo Canyon (DC), intrusion of marine debris (kelp and other marine vegetation) at the circulating water intake structures can occur and, under extreme storm conditions result in high differential pressure across the circulating water traveling screens, loss of circulating water pumps and loss of condenser. Over the past several years, DC has taken significant steps, including changes in operating strategy as well as equipment enhancements, to reduce the vulnerability of the plant to this phenomenon. DC has also taken efforts to minimize kelp, however environmental restrictions on kelp removal and the infeasibility of removing (and maintaining removal of) extensive marine growth for several miles around the plant prevent them from eliminating the source if the storm-driven debris. To minimize the challenge to the plant under storm conditions which could likely result in loss of both circulating water pumps, DC procedurally reduces power to 25% power or less. From this power level, the plant can be safely shut down by control rod motion and use of atmospheric dump valves without the need for a reactor trip.

Is this anticipatory plant shutdown in response to an external event, where DC has taken all reasonable actions within environmental constraints to minimize debris quantity and impact, able to be excluded from being counted under IE01 and IE02?

Response In consideration of the intent of the performance indicators and the extensive actions taken by PG&E to reduce the plant challenge associated with shutdowns in response to severe storm-initiated debris loading, the following interpretation will be applied to Diablo Canyon. A controlled shutdown from reduced power (less than 25%), which is performed in conjunction with securing of the circulating water pumps to protect the associated traveling screens from damage due to excessive debris loading under severe storm conditions, will not be considered a "scram." If, however, the actions taken in response to excessive debris loading result in the initiation of a reactor trip (manual or automatic), the event would require counting under both the Unplanned Scrams (IE01) and Scrams with a Loss of Normal Heat Removal (IE02) indicators.

Initiating Events

IE02 Scrams With Loss of Normal Heat Removal

ID 423

Posting Date 01/17/2007

Question **Appendix D Generic**

Does loss of feedwater as the initiator for the reactor scram require reporting under this PI?

Response The two trips described in the LERs above should not count in this PI. A loss of main feedwater did occur; however, it was deemed that the main feedwater system was considered
easily recoverable from the control room without the need for diagnosis or repair.

ID 407

Posting Date 01/26/2006

Question The
guidance in question is contained on page 13, lines 3 and 4, and 36 through 42 on page 14, lines 15 and 16 of NEI 99-02, Revision 3.

During
initial startup activities of the main turbine, following a refueling outage in which the HP turbine rotor was replaced, with reactor power at approximately 17% of rated thermal power the turbine automatically tripped at approximately 1045 rpm when turbine vibration exceeded the trip setpoint of 12 mils. Following the turbine trip, vibration levels continued to increase to between 22 and 24 mils. As a result, the operators manually tripped the reactor in accordance with a station abnormal operating procedure (AOP) in preparation for breaking condenser vacuum to slow the turbine. The emergency feedwater system actuated on low steam generator levels following the reactor trip. Normal feedwater remained available via the starup feed pump and the main steam isolation valves (MSIVs) remained open during the event. Condenser vacuum was broken at 11:09 until the high vibration condition cleared and was then subsequently restored to provide a secondary heat sink. The high vibration trip signal reset after approximately 20 minutes with turbine speed below 350 rpm. The heat removal process that dumps steam to the main condenser was not in service for approximately one hour (restoration of condenser vacuum was started at 11:40). The unavailability of the condenser for this brief period following the reactor trip was inconsequential. Because of the low decay heat with the new core, the emergency feedwater system alone provided more than the required heat removal capability. There was no temperature increase sufficient to demand operation of the atmospheric or condenser steam dump valves. Emergency feedwater flow needed to be throttled to prevent overcooling the plant. In addition, for this event, restoration of condenser vacuum is uncomplicated and would not require any diagnosis or repair. The actions necessary to establish vacuum include locally closing the manually operated vacuum breaker AR-V122 (condenser vacuum breaker valve) and remotely (control room) aligning the vacuum pump discharge and starting the vacuum pumps. The vacuum breaker closure can be accomplished in approximately one minute once an operator is at the valve. Normal feedwater can be restored by resetting the Feedwater Isolation signal and reopening the associated valves, all actions that are accomplished from the Control Room. In addition, the Startup Feedwater Pump was available to add additional flow to the steam generators if the operator chose to do so. However, as stated above, the emergency feedwater flow was throttled to avoid overcooling.

The turbine
startup was being controlled by the Post Maintenance Turbine Startup procedure, a limited use procedure used for controlling turbine startup following major maintenance. A precaution in the procedure states that higher than normal vibration levels are expected at turbine critical speeds of 800 to 1200 rpm. If, during turbine startup, the vibration levels exceed specified limits, the

procedure directs the operators to implement the Turbine Generator High Vibration abnormal operating procedure (AOP). A reactor trip is a planned evolution when such a turbine trip occurs if it is required to break vacuum to slow the turbine. The Station operating philosophy is that abnormal operating procedures are used in the Control Room instead of test procedures so as not to unduly challenge the operators or remove them from their normal operating roles. The operators are trained on these procedures, are comfortable using them and know what responses are required. Following a turbine trip, the procedure directs the operators to evaluate breaking condenser vacuum if vibration is greater than 14 mils for greater than 10 seconds and independent of critical speeds; i.e., not at a critical speed. The crews were prepared for the evolution and made aware of the critical parameters during the pre job briefing. The briefing was attended by a nuclear systems operator who would have been dispatched to perform the manual action required to restore vacuum by operating AR-V122.

The
licensee and the NRC Senior Resident inspector do not disagree on the facts and circumstances of the event; however, the licensee and the inspector disagree whether the event should count against the performance indicator.

Does this
reactor trip count against the performance indicator for Unplanned Scrams with Loss of Normal Heat Removal?

Response **Appeal Process Decision Not to be used for future reference or incorporation into NEI 99-02.**

The
situation meets the guidance to be counted in the PI. The situation and analysis with respect to the PI is almost identical to FAQ 36.9 for Millstone 2. As noted in that appeal response, the licensee in this case as well took commendable actions in anticipation of potentially high turbine vibration conditions. However, operator actions were required for the safety of the turbine and, therefore, meets the criteria to be counted in the PI. A followup FAQ should be issued to describe those actions necessary to qualify this narrowly-focused event (temporary loss of vacuum following turbine rotor replacement in low decay heat situations) as a futher item for Examples that do not count until the new PI guidance is in place.

ID 397

Posting Date 07/21/2005

Question **Appeal Process Decision (Not to be used for future reference or incorporation into NEI 99-02)**

During startup activities following a
refueling outage in which new monoblock turbine rotors were installed in the LP turbines, reactor power was approximately 10% of rated thermal power, and the main turbine was being started up. Feedwater was being supplied to the steam generators by the turbine driven main feedwater pumps, and the main condensers were in service. During main turbine startup, the turbine began to experience high bearing vibrations before reaching its normal operating speed of 1800 rpm, and was manually tripped. The bearing vibrations increased as the turbine slowed down following the trip. To protect the main turbine, the alarm response procedure for high-high turbine vibration required the operators to manually SCRAM the reactor, isolate steam to the main condensers by closing the main steam isolation valves and to open the condenser vacuum breaker thereby isolating the normal heat removal path to the main condensers. This caused the turbine driven main feedwater pumps to trip. Following the reactor SCRAM, the operators manually started the auxiliary feedwater pumps to supply feedwater to the steam generators.

Based on industry operating experience,
operators expected main turbine vibrations during this initial startup. Nuclear Engineering provided Operations with recommendations on how to deal with the expected turbine vibration issues that included actions up to and including breaking condenser vacuum. Operations prepared the crews for this turbine startup
with several primary actions. First, training on the new rotors, including industry operating experience and technical actions being taken to minimize the possibility of turbine rubs was conducted in the pre-outage Licensed Operator Requalification Training. Second, the Alarm Response Procedures (A-34 and B-34)
for turbine vibrations were modified to include procedures to rapidly slow the main turbine to protect it from damage. Under the worst turbine vibration conditions, the procedure required operators to trip the reactor, close MSIVs and break main condenser vacuum. Third, operating crews were provided training in the form of a PowerPoint presentation for required reading which included a description of the turbine modifications, a discussion of the revised Alarm Response Procedures and industry operating experience.

Does this SCRAM count against the performance indicator for scrams with loss of normal heat removal?

Response **Appeal Process Decision - Not to be used for future reference or incorporation into NEI 99-02.**

The licensee took commendable actions in
anticipation of potential high turbine vibration conditions. When those conditions were experienced, operator actions were driven by recently implemented procedure changes and training, and resulted in a transient that was not very complicated. However, the risk significance of the transient was limited only because of the low decay heat. The normal heat removal path was lost and it was not easily or readily recoverable from the control room. Operator actions were required for the safety of the turbine. This situation meets the criteria to be counted in the PI.

ID 388

Posting Date 05/19/2005

Question On August 14, 2003 Ginna Station scrammed due to the wide spread grid disturbance in the Northeast United States. Subsequent to the scram, Main Feedwater Isolation occurred as designed on low Tavg coincident with a reactor trip. However, due to voltage swings from the grid disturbance, instrument variations caused the Advanced Digital Feedwater Control System (ADFCS) to transfer to manual control. This transfer overrode the isolation signal causing the Main Feedwater Regulation Valves (MFRVs) to go to, and remain at, the normal or nominal automatic demand position at the time of the transfer, resulting in an unnecessary feedwater addition. The feedwater addition was terminated when the MFRVs closed on the high-high steam generator level (85%) signal. Operators conservatively closed the MSIVs in accordance with the procedure to mitigate a high water level condition in the Steam Generators. Decay heat was subsequently removed using the Atmospheric Relief Valves (ARVs). Should the scram be counted under the PI "Unplanned Scrams with Loss of Normal Heat Removal?"

Response Appeal Process Decision - Not to be used for future reference or incorporation into NEI 99-02.

Ginna--The scram was influenced by the grid instabilities that caused other plants to scram. I considered this akin to a partial loss of offsite power. The scram was not complicated and the operators were in a functional recovery procedure 18 minutes after the scram when the MSIVs were closed. These aspects overrode the aspect of local actions that were required to reopen the MSIVs. Should not be counted in the PI.

ID 387

Posting Date 05/19/2005

Question Should an "Unplanned Scram with a Loss of Normal Heat Removal" be reported for the Peach Bottom Unit 2 (July 22, 2003) reactor scram followed by a high area temperature Group I isolation?

Description of Event:

At approximately 1345 on 07/22/03, a Main Generator 386B and 386F relay trip resulted in a load reject signal to the main turbine and the main turbine control valves went closed. The Unit 2 reactor received an automatic Reactor Protection System (RPS) scram signal as a result of the main turbine control valves closing. Following the scram signal, all control rods fully inserted and, as expected, Primary Containment Isolation System (PCIS) Group II and III isolations occurred due to low Reactor Pressure Vessel (RPV) level. The Group III isolation includes automatic shutdown of Reactor Building Ventilation. RPV level control was re-established with the Reactor Feed System and the scram signal was reset at approximately 1355 hours.

At approximately 1356 hours, the crew received a High Area Temperature alarm for the Main Steam Line area. The elevated temperature was a result of the previously described trip of the Reactor Building ventilation system. At approximately 1358, a PCIS Group I isolation signal occurred due to Steam Tunnel High Temperature resulting in the automatic closure of all Main Steam Isolation Valves (MSIV).Following the MSIV closure, the crew transitioned RPV pressure and level control to the High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) systems. Following the reset of the PCIS Group II and III isolations at approximately 1408, Reactor Building ventilation was restored.

At approximately 1525, the PCIS Group I isolation was reset and the MSIVs were opened. Normal cooldown of the reactor was commenced and both reactor recirculation pumps were restarted. Even though the Group I isolation could have been reset following the Group II/III reset at 1408, the crew decided to pursue other priorities before reopening the MSIVs including: stabilizing RPV level and pressure using HPCI and RCIC; maximizing torus cooling; evaluating RCIC controller oscillations; evaluating a failure of MO-2-02A-53A "A" Recirculation Pump Discharge Valve; and, minimizing CRD flow to facilitate restarting the Reactor Recirculation pumps.

Problem Assessment:

It is recognized that loss of Reactor Building ventilation results in rising temperatures in the Outboard MSIV Room. The rate of this temperature rise and the maximum temperature attained are exacerbated by summertime temperature conditions. When the high temperature isolation occurred, the crew immediately recognized and understood the cause to be the loss of Reactor Building ventilation. The crew then prioritized their activities and utilized existing General Plant (GP) and System Operating (SO) procedures to re-open the MSIVs.

Reopening of the MSIVs was:

- easily facilitated by restarting Reactor Building ventilation,
- completed from the control room using normal operating procedures
- without the need of diagnosis or repair

Therefore, the MSIV closure does not meet the definition of "Loss of normal heat removal path" provided in NEI 99-02, Rev. 2, page 15, line 37, and it is appropriate not to include this event in the associated performance indicator Unplanned Scrams with Loss of Normal Heat Removal.

Discussion of specific aspects of the event:

Was the recognition of the condition from the Control Room?

- Yes. Rising temperature in the Outboard MSIV Room is indicated by annunciator in the main control room. Local radiation levels are also available in the control room. During the July 22, 2003 scram, control room operators also recognized that the increase in temperature was not due to a steam leak in the Outboard MSIV Room because the local radiation monitor did not indicate an increase in radiation levels. Initiation of the Group I isolation on a Steam Tunnel High Temperature is indicated by two annunciators in the control room.

Does it require diagnosis or was it an alarm?

- The event is annunciated in the control room as described previously.

Is it a design issue?

- Yes. The current Unit 2 design has the Group I isolation temperature elements closer to the Outboard MSIV Room ventilation exhaust as compared to Unit 3. As a result, the baseline temperatures, which input into the Group I isolation signal, are higher on Unit 2 than Unit 3.

Are actions virtually certain to be successful?

- The actions to reset a Group I isolation are straight forward and the procedural guidance is provided to operate the associated equipment. No diagnosis or troubleshooting is required.

Are operator actions proceduralized?

- The actions to reset the Group I isolation are delineated in General Plant procedure GP-8.A "PCIS Isolation-Group I." The actions to reopen the MSIVs are contained in System Operating procedures SO 1A.7.A-2 "Main Steam System Recovery Following a Group I Isolation" and Check Off List SO 1A.7.A-2 "Main Steam Lineup After a Group I Isolation." These procedures are performed from the control room.

How does Training address operator actions?

The actions necessary for responding to a Group I isolation and subsequent recovery of the Main Steam system are covered in licensed operator training.

Are stressful or chaotic conditions during or following an accident expected to be present?

- As was demonstrated in the event of July 22, 2003, sufficient time existed to stabilize RPV level and pressure control and methodically progress through the associated procedures to reopen the MSIVs without stressful or chaotic conditions

Response Appeal Process Decision - Not to be used for future reference or incorporation into NEI 99-02.

Peach Bottom--Scram was somewhat complicated since the unit experienced a Group I isolation signal. Local operations were required to restart the ventilation system in order to reset the isolation signal. Some diagnosis would have been prudent to assure there was no steam line break before resetting the signal. Should be counted in the PI.

ID 386

Posting Date 05/19/2005

Question With the unit in RUN mode at 100% power, the control room received indication that a Reactor Pressure Vessel relief valve was open. After taking the steps directed by procedure to attempt to reseat the valve without success, operators scrammed the reactor in response to increasing suppression pool temperature. Following the scram, and in response to procedural direction to limit the reactor cooldown rate to less than 100 degrees per hour, the operators closed the Main Steam Isolation Valves (MSIVs). The operators are trained that closure of the MSIVs to limit cool down rate is expected in order to minimize steam loss through normal downstream balance-of-plant loads (steam jet air ejectors, offgas preheaters, gland seal steam).

At the time that the MSIVs were closed, the reactor was at approximately 500 psig. One half hour later, condenser vacuum was too low to open the turbine bypass valves and reactor pressure was approximately 325 psig. Approximately eight hours after the RPV relief valve opened, the RPV relief valve closed with reactor pressure at approximately 50 psig. This information is provided to illustrate the time frame during which the reactor was pressurized and condenser vacuum was low.

Although the MSIVs were not reopened during this event, they could have been opened at any time. Procedural guidance is provided for reopening the MSIVs. Had the MSIVs been reopened within approximately 30 minutes of their closure, condenser vacuum was sufficient to allow opening of the turbine bypass valves. If it had been desired to reopen the MSIVs later than that, the condenser would have been brought back on line by following the normal startup procedure for the condenser.

As part of the normal startup procedure for the condenser, the control room operator draws vacuum in the condenser by dispatching an operator to the mechanical vacuum pump. The operator starts the mechanical vacuum pump by opening a couple of manual valves and operating a local switch. All other actions, including opening the MSIVs and the turbine bypass valves, are taken by the control room operator in the control room. It normally takes between 45 minutes and one hour to establish vacuum using the mechanical vacuum pump.

The reactor feed pumps and feedwater system remained in operation or available for operation throughout the event. The condenser remained intact and available and the MSIVs were available to be opened from the control room throughout the event. The normal heat removal path was always and readily available (i.e., use of the normal heat removal path required only a decision to use it and the following of normal station procedures) during this event.

Does this scram constitute a scram with a loss of normal heat removal?

Response Appeal Process Decision - Not to be used for future reference or incorporation into NEI 99-02.

Quad Cities--Scram was complicated with the failure of the RPV Relief Valve to seat. Rising torus temperatures and declaration of an Alert required operator attention. Having a relief valve remain open after a scram is an off-normal condition. Should be counted in the PI.

ID 385

Posting Date 05/19/2005

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?

Response Appeal Process Decision - Not to be used for future reference or incorporation into NEI 99-02.

Perry--The scram was not very complicated. The TDFWPs were readily available since the licensee had a special procedure for fast recovery and had included it as a part of routine requalification program training. Should not be counted in the PI.

ID 384

Posting Date 05/19/2005

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?

Response Appeal Process Decision - Not to be used for future reference or incorporation into NEI 99-02.

LaSalle--Scram was somewhat complicated by the uncertainties caused by the FW control system failures (recirculation pump speed changes, reactor vessel water level changes, and motor driven FW pump inability to deliver flow due to the discharge valve failure to open). In addition, some RCIC instabilities required operator attention to control water level. A normal operating procedure (rather than a fast recovery procedure that was part of requal training) was available to restart the TDFWPs, but it includes steps that require local observation. Before those steps could be NA'ed by the operator some diagnosis would have been prudent, given the FW system disturbances. Should be counted in the PI.

ID 379

Posting Date 03/17/2005

Question NEI 99-02R2, Pages 15-16, states:

Loss of the normal heat removal path: when any of the following conditions have occurred and cannot be easily recovered from the control room without the need for diagnosis or repair to restore the normal heat removal path: failure of turbine bypass capacity that results in insufficient bypass capability remaining to maintain reactor temperature and pressure The determining factor for this indicator is whether or not the normal heat removal path is available, not whether the operators choose to use that path or some other path Operator actions or design features to control the reactor cooldown rate or water level, such as closing the main feedwater valves or closing all MSIVs, are not reported in this indicator as long as the normal heat removal path can be readily recovered from the control room without the need for diagnosis or repair. However, operator actions to mitigate an off-normal condition or for the safety of personnel or equipment (e.g., closing MSIVs to isolate a steam leak) are reported. Example of loss of turbine bypass capability: sustained use of one or more atmospheric dump valves (PWRs) Examples that do not count: partial losses of condenser vacuum or turbine bypass capability after an unplanned scram in which sufficient capability remains to remove decay heat

On June 4, 2004, Unit 3 was manually tripped due to a heavy influx of red sea grass on the intake to the circulating water pumps. This resulted in securing of 3 of the 4 circulating water pumps. Following the trip, one circulating water pump remained in service and maintained normal condenser vacuum. However, approximately 5 minutes post-trip the Steam Bypass Control System began to not function as designed in auto (later determined to be a faulty permissive channel), and the operators choose to transfer to the Atmospheric Steam Dump Valves (ADVs) to control RCS temperature. The MSIVs remained open and one quadrant of the condenser remained available. Since ADVs are a procedural option to use, and they were working as designed, the choice to look into whether or not the SBCS control valves would function in manual was not pursued. Since the problem with the SBCS was in the permissive circuit the SBCS valves would have operated as expected from the control room in Automatic (with manual permissive).

We believe we meet the requirement for a normal heat removal flow path, and the use of the ADVs were elective on the part of the Operators. In summary, there was not: (1) a complete loss of all main feedwater flow; (2) insufficient main condenser vacuum to remove decay heat; (3) complete closure of at least one MSIV in each main steam line; nor (4) failure of turbine bypass capacity that results in insufficient bypass capability remaining to maintain reactor temperature and pressure. Nevertheless, since there was prolonged operation of the ADVs, is this considered a loss of turbine bypass capability and therefore a loss of RCS heat removal?

Response No. Although operators chose to use the Atmospheric Dump Valves, the normal heat removal path remained available (the Main Steam Isolation Valves remained open, the condenser was available, and the Steam Bypass Control System was available and would have operated as expected from the control room in automatic [with manual permissive]).

ID 355

Posting Date 10/23/2003

Question This question seeks clarification of the description of events that are not to be counted as a Scram with Loss of Normal Heat Removal (Scram w/LONHR), specifically page 16, lines 36-37, of NEI 99-02.

At our plant, an automatic scram occurred due to a turbine trip from a load reject along with a simultaneous loss of offsite power to the Power Conversion System (PCS) with a total loss of power to PCS after the turbine/generator output breaker opened. Power to two of three Emergency Safety Feature (ESF) transformers were lost. All three of the emergency diesel generator divisions started and aligned to the three busses previously fed from the two lost transformers. The third ESF transformer is powered by an independent 115 Kv line and was not lost during the event.

The NRC Senior Resident agrees this was not a design basis loss of offsite power event to the Emergency Core Cooling System (ECCS). However, the NRC Senior Resident interprets the referenced exemption is not applicable in this case.
The NEI 99-02 guidance noted above exempts the loss of offsite power but does not explicitly address a situation where a partial loss of offsite power occurred that resulted in a complete loss of offsite power to the power conversion system.

Event Description:
Our plant automatically scrammed at 0948 CDST on 4/24/2003 due to a turbine trip from a load reject. Breakers opened in both the local switchyard and in remote switchyards that removed all paths of generation onto the grid and offsite power to the power conversion system. At the time of the scram, there was a severe thunderstorm in the vicinity. High winds caused a closure of an open disconnect into a grounded breaker under on-going maintenance. This lockout condition led to protective relaying actuating to isolate the fault, and caused the load

reject.

During the event, Division 1, 2 and 3 Diesel Generators (DGs) started and energized their respective safety busses. All safety systems functioned as designed and responded properly. During this transient, no deviations were noted in any safety functions.

Offsite power was automatically restored to the East 500 KV bus, once the main turbine output breaker opened and the fault was cleared. The West 500 KV bus, which was undergoing maintenance at the time of the event, remained deenergized.
While all three DGs started and supplied their buses, this did **not** constitute a design bases Loss Of Offsite Power (LOOP) and an emergency declaration of an unusual event because one of the three sources of off site power (a 115KV line to Engineered Safety Feature (ESF) Transformer 12 (ESF12) remained energized and was available throughout the event. Any of the three ECCS buses could have been transferred to this source of power at any time during the event.

Based on the above considerations, it is concluded that this event would be best modeled as a T2, or Loss of PCS (Power Conversion System), initiator. A T2 initiator results in the loss of the power conversion systems (feedwater, condenser, and condensate) and the modeling of this event does allow for recovery of the power conversion systems.

Under the current Revision 2 of NEI 99-02, does this Scram count as a Scram with Loss of Heat Removal?

Response No. The 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. There is no distinction made or implied regarding a complete or partial loss of offsite power. In this case, while the loss of offsite power was not a complete loss, the loss did affect the feedwater, condensate and condenser systems.

ID 347

Posting Date 05/22/2003

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

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 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 Yes. Closure of MSIVs to mitigate an off-normal condition (i.e., stopping reactor coolant system pressure from reaching an automatic safety injection setpoint) is counted in the performance indicator as an Unplanned Scram with Loss of Normal Heat Removal.

ID 310

Posting Date 05/22/2002

Question On June 5, 2000, a S/G perturbation occurred because of rain-damaged main feed water pump turbine speed control circuitry. Due to rainwater in its speed control panel, the 2B main feedwater pump sped up uncontrollably, then slowed down. Consequently, the 2A pump automatically compensated by lowering and raising its speed in attempts to maintain steam generator levels within program. This cycle continued until the pumps master controller was placed in "manual," allowing operators to take control of the pump speeds. Moments later, the main turbine and reactor tripped on Hi-Hi Steam Generator level (P-14) and a feedwater isolation signal resulted in both turbine-driven feed pumps tripping. The auxiliary feedwater system responded as designed and the plant was stabilized within minutes.
At the time of the event, because both pumps were cycling, the licensee did not know if both main feed pumps speed control circuitry were affected/damaged by rainwater. Approximately two hours later a work order was generated for the 2A pump, which contained the instructions: "before doing anything at all, engineering requests that 'as found' readings be taken on all power supplies before anything is reset...remove any moisture from the cabinet. Make any needed repairs to return pump to service." It was determined shortly after the event that the 2A pumps circuitry had not been affected by the rainwater. None of the troubleshooting associated with the 2A pump would have prevented it from operating in manual had the operators attempted to start it. Ultimately, only the 2B pump was placed under clearance to allow repairs to its control circuitry, which had been clearly damaged.

To determine whether this event constituted a Scram with LONHR, the licensee asked the operators who were on shift (in hindsight) would they have attempted to start the 2A pump in manual if the need had arisen. Operators responded that they would. The inspector reviewed the licensees emergency operating procedures, specifically the functional restoration procedure for the loss of secondary heat sink, FR-H.1, and determined that operators are directed to attempt to start one of the main feed pumps (through a series of steps) if a problem occurs with the auxiliary feedwater systemShould this count as a Scram with Loss of Normal Heat Removal?

Response No. This situation occurred June 5, 2000 while Revision 0 of NEI 99-02 was in effect. This would not count as a scram with loss of normal heat removal because at least one main feedwater pump was available..

ID 303

Posting Date 03/21/2002

Question **Appendix D - Ginna**

NEI 99-02 Rev 1, states in part on page 14, lines 11 - 14: "Intentional operator actions to control the reactor water level or cool down rate, such as securing main feedwater or closing the MSIVs, are not counted in this indicator, as long as the normal heat removal path can be easily recovered from the control room without the need for diagnosis or repair to restore the normal heat removal path."

Revision 1 added the wording "as long as the normal heat removal path can be easily recovered from the control room without the need for diagnosis or repair to restore the normal hear removal path." to this statement.

If the MSIVs are closed to control cooldown rate following a scram or normal shutdown at our station, the MSIVs are not reopened. In Mode 3, Operators typically close the MSIVs as part of procedurally directed shutdown activities to assist in controlling the cooldown rate and pressurizer level, and to perform IST and Technical Specification required testing. Once the Operators intentionally close the MSIVs, they, by procedure, do not reopen them. In fact, for normal plant shutdowns on 3/1/99 and 9/18/00, operators closed the MSIVs as early as 2 hours upon entering Mode 3. For two reactor trips, one on 4/23/99 from intermediate range issues and one on 4/27/99 from an OTDT issue, the MSIVs were closed for control purposes within ~10 minutes of the reactor trip as allowed by plant procedures. The secondary system was available in both of these instances.

The MSIV bypass valves at our station cannot be operated from the Main Control Board or anywhere else in the Control Room. Original design of our station's MSIVs requires an Aux Operator to open a bypass valve located at the MSIVs prior to reopening the MSIVs, thus requiring operator action outside the control room. This action is an operational task that is considered to be uncomplicated and is virtually certain to be successful during the conditions in which it is performed. However, it would require diagnosis, as it is not the normal procedural method for the Operators to control cooldown rate once the MSIVs are closed. Does the closure of the MSIVs, while in Mode 3 or lower, to control cooldown rate, pressurizer level, or to perform testing following a scram constitute a scram with loss of normal heat removal?

Response No. Because the normal plant response to a scram without complications requires the MSIVs to be closed to control the cooldown rate, and the operators are instructed and trained to do this after every scram, such a scram would not count as a scram with loss of normal heat removal.

ID 299

Posting Date 01/25/2002

Question While performing routine Unit 2 maintenance, personnel in the control room placed one channel of main steam line pressure instrumentation in test. Next, they notified a field technician to isolate the associated pressure transmitter. The field technician isolated the wrong transmitter and immediately notified the control room. This condition satisfied the 2/3 logic for lo lo steam line pressure and initiated a main steam isolation signal. The main steam isolation valves (MSIVs) on all four loops closed. The steam line code relief valves and the pressurizer power operated relief valves opened. The reactor tripped on overtemperature delta temperature. The condenser dump valves opened and began blowing down the steam chest. The main feedwater pumps went to rollback hold. In rollback hold, the main feedwater pumps can be aligned from the control room to the auxiliary steam supply system which receives its steam from the opposite unit. At the time, Unit 1 was operating at 100 percent power. The auxiliary feedwater system started upon receipt of a steam generator lo lo level signal.
Operators immediately entered the reactor trip procedure. The main steam isolation signal was reset. Approximately 35 minutes after reactor trip, the main steam bypass valves were opened. This provided a heat removal path and began to equalize the pressure differential across the MSIVs. At the time, main steam line pressure upstream of the MSIVs was approximately 1100 psig while pressure in the steam chest (downstream of the MSIVs) was approximately 70 psig. By design, a differential pressure of less than 50 psid must be established across the MSIVs prior to opening them. Approximately 50 minutes after opening the MSIV bypass valves, pressure had been equalized. All four MSIVs were opened approximately two hours after the reactor trip. This restored the normal heat removal path through the MSIVs and back to the main condenser. The normal heat removal path could have been recovered sooner. However, Operations did not see any need to restore the path sooner since the plant was stable and heat was being removed by main feedwater and the steam line code relief valv

Following the reactor trip, operators entered the applicable reactor trip procedure and initiated all recovery actions from the control room. There was no need for diagnosis or repair. All safety systems functioned as required. Main feedwater was available and reestablished per the reactor trip procedure. Condenser vacuum was maintained at all times. The normal heat removal path through the MSIVs was not recovered for approximately two hours after the reactor trip; however, this path could have been recovered sooner if desired. Does this count as a scram with loss of normal heat removal?

Response Yes. The normal heat removal path was lost and an alternate path was required for heat removal.

ID 287

Posting Date 09/12/2001

Question Should the following reactor trip described in the scenario below be reported as a Scram with Loss of Normal Heat Removal? Following a reactor trip, No. 11 Moisture Separator/Reheater second-stage steam source isolation valve (1-MS-4025) did not close. The open valve increased the cooldown rate of the Reactor Coolant System. Control Room Operators closed the main steam isolation valves and used the atmospheric dump valves to control Reactor Coolant System temperature. Within three hours, 1-MS-4025 was shut manually. Control Room Operators opened the main steam isolation valves, and Reactor Coolant System temperature control using turbine bypass valves was resumed.

Response Yes. The normal heat removal path could not be restored from the control room without diagnosis or repair to restore the normal heat removal path. In this case, manual action was necessary outside the control room to manually isolate a valve to restore the normal heat removal path.

ID 286

Posting Date 09/12/2001

Question Should the following reactor trip described in the scenario below be reported as a Scram with Loss of Normal Heat Removal? A loud noise was heard in the Control Room from the Unit 2 Turbine Building. Operators noted a steam leak, but could not determine the source of the steam because of the volume of steam in the area. It was suspected that the leak was coming from the No. 21 or 22 Moisture Separator Reheater (MSR). The steam prevented operators from accessing the MSR manual isolation valves. Due to the difficulty in determining the exact source of the leak, the potential for personnel safety concerns, and the potential for equipment damage due to the volume of steam being emitted into the Turbine Building, operators manually tripped the Unit. After the manual trip, a large volume of steam was still being emitted, and the shift manager had the main steam isolation valves (MSIVs) shut. Once the MSIVs where shut, the operators identified a ruptured 2?inch diameter vent line from No. 21 MSR second stage to No. 25A Feedwater Heater. The operators shut the second stage steam supplies and isolated the leak. Once the leak was isolated, the MSIVs were opened and normal heat removal was restored. The majority of the steam that was emitted following the trip was due to all the fluid in the MSR and feedwater heater escaping from the pipe.

Response Yes. Investigation and diagnosis were required to determine that the main steam isolation valves could be reopened.

ID 282

Posting Date 08/16/2001

Question Some plants are designed to have a residual transfer of the non-safety electrical buses from the generator to an off-site power source when the turbine trip is caused by a generator protective feature. The residual transfer automatically trips large electrical loads to prevent damaging plant equipment during reenergization of the switchgear. These large loads include the reactor feedwater pumps, reactor recirculation pumps, and condensate booster pumps. After the residual transfer is completed the operators can manually restart the pumps from the control room. The turbine trip will result in a reactor scram. Should the trip of the reactor feedwater pumps be counted as a scram with a loss of normal heat removal?

Response No. In this instance, the electrical transfer scheme performed as designed following a scram and the residual transfer. In addition the pumps can be started from the control room. Therefore, this would not count as a scram with a loss of normal heat removal.

ID 264

Posting Date 04/04/2001

Question Should the reactor trip described in the scenario below be included as a "Scram with Loss of Normal Heat Removal?"
A very heavy rainfall caused the turbine building gutters to overflow and water entered the interior of the turbine building. Water subsequently leaked onto the main feedwater pump B area and affected the pump speed control circuitry. Feedwater pump B speed increased and feedwater pump A speed decreased to compensate. Shortly thereafter feedwater pump B speed decreased and feedwater pump A increased. The control room operators placed the feedwater pump turbine master speed controller in manual in an attempt to recover from the transient. This action stabilized pump speed.

The transient caused the digital feedwater control system to place the feedwater regulating valves in manual control. Levels in steam generators B, C, and D began to rise.

A hi-hi steam generator level (P-14) occurred in steam generator B. The P-14 signal tripped both main feedwater pumps, generated a feedwater isolation signal, and tripped the main turbine. The reactor tripped upon turbine trip. Main feedwater pumps tripped on the P-14 signal as part of the plant design. Feedwater pump B had malfunctioned; however, feedwater pump A remained available. Auxiliary feedwater system automatic starts occurred for motor driven pumps A and B as well as the turbine driven auxiliary feedwater pump (all of these responses were as designed).

Response No, because the MFW system was readily restorable to perform its post trip cooldown function.

ID 249

Posting Date 02/08/2001

Question **This FAQ is a replacement for FAQ 142. FAQ 142 has been withdrawn.**

Under the Scram with Loss of Normal Heat Removal performance indicator in NEI 99-02 Draft D, the Definition of Terms states that a loss of normal heat removal path has occurred whenever any of the following conditions occur:·loss of main feedwater,·loss of main condenser vacuum,·closure of main steam isolation valves·or loss of turbine bypass capability. The purpose of the indicator is to count scrams that require the use of mitigating systems, however, instances that meet the above criteria in a literal sense could occur without the necessity of using mitigating systems. To illustrate, would the following two examples constitute scrams with loss of normal heat removal?

1. A short term loss of main feedwater injection capability due to pump trip on high reactor water level post-scram is a BWR event. Under these conditions, there is ample time to restart the main feed pumps before addition of water to the vessel via HPCI or RCIC is required.

2. A second example would be a case where the turbine bypass valves (also commonly called steam dump valves) themselves are unavailable, but sufficient steam flow path to the main condenser exists via alternate paths (such as steam line drains, feed pump turbine exhausts, etc.) such that no mitigating systems are called upon.

Response 1. No. The determining factor in this indicator is whether or not the normal heat removal path is available to the operators, not whether the operators choose to use that or some other path. The indicator excludes events in which the normal heat removal path through the main condenser is easily recoverable without the need for diagnosis or repair.
2. Yes. The normal flow path is not being used in this example.

ID 248

Posting Date 02/08/2001

Question In the Scrams With a Loss of Normal Heat Removal performance indicator, the definition of "loss of normal heat removal path" includes loss of main feedwater. Our plant is designed to isolate main feedwater after a trip by closing the main feedwater control valves. The auxiliary feedwater pumps then are designed to start on low steam generator level (which is expected following operation above low power conditions), providing our normal heat removal. A clarifying note in the Guideline clearly states that "Design features to limit the reactor cooldown rate, such as closing the main feedwater valves on a reactor scram, are not counted in this indicator." Also, the response to FAQ 65 states that "The PI is monitoring the use of alternate means of decay heat removal following a scram." Our plant received a spurious invalid feedwater isolation signal due to technician error, causing turbine trip, reactor trip, main feedwater pump trip and closure of feedwater regulation valves. The auxiliary feedwater pumps started on the loss of the main feedwater pumps, prior to reaching a low SG level condition. Operators could have restored main feedwater from the control room in this case with a few simple actions. This action is proceduralized. This is not believed to be a Scram with a Loss of Normal Heat Removal. Is this the correct interpretation?

Response Yes. This is an appropriate interpretation, because the MFW pumps are considered to be easily recoverable without the need for diagnosis or repair.

ID 142

Posting Date 02/08/2001

Question FAQ 142 has been withdrawn and replaced by FAQ 249.

Response

ID 238

Posting Date 01/10/2001

Question Crystal River Unit 3 (CR-3) is configured with two once-through steam generators (OTSGs). Two Main Steam Isolation Valves (MSIVs) are installed in each of the two main steam lines.
On August 27, 1998, CR-3 was in MODE 1 operating at 100 percent RATED THERMAL POWER. While troubleshooting a half trip signal on the Emergency Feedwater Initiation and Control (EFIC) System Channel A Main Steam Line Isolation (MSLI), both MSIVs to OTSG A closed. This action isolated steam relief to the condenser through the turbine bypass valves from the A OTSG and isolated the steam supply to Main Feedwater Pump (MFP) A. As requiredby administrative procedures, the reactor operator initiated a manual trip upon closure of the MSIVs.

After the manual trip, the OTSG A level lowered enough to initiate Emergency Feedwater (EFW). EFW controlled level in both OTSGs as designed, although MFP B remained in service and available at all times. OTSG B provided RCSheat removal to the condenser with EFW maintaining OTSG level.

Does this count?

Response No. It must be a complete loss of normal heat removal to count in this indicator.

ID 220

Posting Date 10/01/2000

Question Following a plant trip, operators closed the MSIVs due to a stuck open steam dump valve. RCS temperature was maintained using atmospheric dump valves. Does this count as a scram with loss of normal heat removal?

Response Yes. The MSIVs could not be recovered because of the stuck open steam dump valve.

ID 204

Posting Date 10/01/2000

Question (This FAQ is a replacement for FAQ 196. FAQ 196 has been withdrawn)
During a startup following a refueling outage (reactor at 24% power w/minimal decay heat), one feed water regulating valve failed open causing a loss of feed water control. In response, one of the two feed water pumps was manually tripped to minimize overfeeding of the steam generators. SG levels continued to rise, so the reactor was manually scrammed. Within one minute of scram, with normal heat removal still available through both main feedwater bypasses, the failed open feed water regulating valve was isolated by closing it's feed water block valve as part of Standard Post Trip Actions. Operators quickly diagnosed this as an uncomplicated reactor trip and completed the remaining steps of Standard Post Trip Actions. Eleven minutes after the scram with steam generator levels continuing to slowly rise, the remaining feed water pump was stopped to terminate overfeeding of the steam generators and avoid excess RCS cooldown. Nineteen minutes after the scram, the Reactor Trip Recovery procedure was entered. Thirty nine minutes after the scram, with steam generator levels down to normal levels, AFW was established at 81 gpm for normal startup feed water alignment. Three minutes later, the Plant Startup procedure was initiated.

Mitigating systems such as Aux feed and Atmospheric Dump valves were not required nor used to establish scram recovery conditions. Rather, steam generator inventory provided by normal feed water and the normal

steam path to main condenser via the normal steam bypass control system accounted for 100% capability for post scram RCS heat removal (i.e., no loss ofcapability for performing the heat removal function). Would this event count as a scram with loss of normal heat removal?

Response No. The indicator counts events in which the normal heat removal path through the main condenser is not available and is not easily recoverable from the control room without the need for diagnosis or repair. In this event, the main feedwater system could have easily been returned to service at any time if needed.

ID 196

Posting Date 10/01/2000

Question FAQ 196 has been withdrawn and replaced by FAQ 204.

Response

ID 180

Posting Date 05/24/2000

Question We have two normal methods for removing decay heat. One method uses the main steam system through the condenser steam dumps into the main condenser. This system is normally aligned during power operations to automatically regulate Reactor Coolant temperature, and will control temperature following a reactor scram without operator action. The second system uses atmospheric steam dumps, which are also normally in automatic to control steam generator pressure. This second method will regulate reactor coolant temperature by controlling steam generator pressure with no operator action. As a backup to both of these, we have installed code safety valves on each steam generator.NEI 99-02 states, for scrams with a loss of normal heat removal, that the purpose of the indicator is to monitor "that subset of unplanned and planned automatic and manual scrams that necessitate the use of mitigating systems and are therefore more risk-significant than uncomplicated scrams." Since both of the methods described above are capable of automatically removing decay heat following a scram, should we count only those scrams in which we lose both the condenser steam dumps and the atmospheric steam dumps and their associated feed methods?

Response For consistency throughout the industry, the indicator counts the number of scrams in which the normal heat removal path through the main condenser is lost prior to establishing reactor conditions that allow use of the plants normal long term heat removal systems. A loss of normal heat removal path through the main condenser, necessitating the use of atmospheric steam dumps or code safety valves would be counted. The Clarifying Notes do however allow the exception of intentional operator actions to control reactor cooldown rate.

ID 65

Posting Date 01/07/2000

Question Does the Scrams with a Loss of Normal Heat Removal PI include main condenser perturbations that result in scrams. For example, if a scram occurs due to a partial or total loss of main feedwater and then, as expected, main feedwater is isolated as part of the plant design following the scram, does this count as a Scram with a Loss of Normal Heat Removal. Similarly, do scrams that occur due to a partial loss of condenser vacuum affect this PI.

Response The PI is monitoring the use of alternate means of decay heat removal following a scram. Therefore, the described feedwater scenario would not be included in the PI. Similarly, a partial loss of condenser vacuum that results in a scram yet provides adequate decay heat removal following the scram would not be included in the PI.

ID 4

Posting Date 11/11/1999

Question The NEI 99-02 instructions for Scrams With Loss of Normal Heat Removal (LONHR) equate LONHR with "loss of main feedwater." At some plants the feedwater pumps trip on high reactor water level, which normally occurs on most scrams. To prevent the feedwater pumps from tripping on a scram, the operator has to quickly take manual control of level. Since the operators often have more important concerns during a scram (e.g., trying to figure out what happened, verifying all the rods are in, etc.) they have been instructed (correctly) to let the pumps trip. When this occurs steam continues to flow to the condenser and make up to the reactor is accomplished using other means (e.g., CRD pumps). Does this count as a hit against the LONHR indicator?

Response In this instance, because the system actions and operator response for this plant are normal expected actions following a scram, this would not count against the LONHR indicator.

Initiating Events

IE03 Unplanned Power Changes

ID 421

Posting Date 01/17/2007

Question NEI 99-02 Guidance needing interpretation: Page 17 Lines 42 through Page 18 line 5

Event or circumstances requiring guidance interpretation:

NEI 99-02 requests FAQs be submitted in the following circumstances:

Anticipated power changes greater than 20% in response to expected environmental problems (such as accumulation of marine debris, biological contaminants, or frazil icing) which are proceduralized but cannot be predicted greater than 72 hours in advance may not
need to be counted unless they are reactive to the sudden discovery of off normal conditions. The licensee is expected to take reasonable steps to prevent intrusion of marine or other biological growth from causing power reductions. The circumstances of each situation are different and should be identified to the NRC in a FAQ so that a determination can be made concerning whether the power change should be counted.

During summer months, under certain environmental conditions, Calvert Cliffs can experience instances of significant marine life impingements which can cause high differential pressure across our Circulating Water (bay water) System traveling screens, restricting flow capability of our Circulating Water (CW) pumps which could ultimately result in a plant derate or trip due to being unable to maintain sufficient condenser vacuum.

In anticipation of these potential marine life impingement conditions, the site
has proceduralized actions to be taken within an Abnormal Operating Procedure (AOP). The
actions to be taken in these circumstances include placing travel screens in manual mode of
operation and using the intake aerator and fire hoses to disperse the fish population. Although instances of biological blockages are expected, neither the time of, nor the severity of the intrusions, can be predicted.

During July 2006 the site had been periodically dealing with instances of
jellyfish intrusions which had challenged maintaining sufficient CW flow, but had not been severe enough to threaten plant full power operation. On July 7, 2006 the site experienced a
severe jellyfish intrusion and implemented the applicable AOP. This time the actions were unable to ensure sufficient CW flow to maintain Unit 1 at 100% power and a rapid power reduction was initiated on Unit 1, which ultimately reduced power to 40%. When the jellyfish intrusion was controlled, sufficient CW flow was restored, and power was restored to 100%. Given that the circumstances of this jellyfish intrusion was beyond the control of the plant, and that appropriate site actions have been proceduralized, should this event be exempted from counting as an unplanned power change? In addition, can this exemption be
applied to future, similar marine life impingements at Calvert Cliffs, where the site carries out the approved actions designed to counter act these conditions, without submittal of future FAQs?

In summary, an error was made in application of the NEI 99-02R4, Section F.1.3.4 guidance.

Response The downpower that is described in this FAQ does count. The facility has not developed a specific procedure to proactively monitor for environmental conditions that would lead to jelly fish intrusion, to direct proactive actions to take before the intrusion, and actions to take to mitigate an actual intrusion that are appropriate for the station and incorporate lessons learned: e.g.: staging equipment, assigning additional personnel or watches, implementing finer mesh screen use, use of hose spray to ward off jelly fish. Development and use of such a procedure in the future, may provide the basis for a future FAQ allowing excluding a downpower >20% for this PI.

No change to PI guidance is needed.

ID 420

Posting Date 01/17/2007

Question **Appendix D Oyster Creek**

Page 17 line 42 through page 18 line 5:

Anticipated power changes greater than 20% in response to expected environmental problems (such as accumulation of marine debris, biological contaminants, or frazil icing) which are proceduralized but cannot be predicted greater than 72 hours in advance may not need to be counted unless they are reactive to the sudden discovery of off-normal conditions. However, unique environmental conditions, which have not been previously experienced and could not have been anticipated and mitigated by procedure or plant modification, may not count, even if they are reactive. The licensee is expected to take reasonable steps to prevent intrusion of marine or other biological growth from causing power reductions. Intrusion events that can be anticipated as a part of a maintenance activity or as part of a predictable cyclic behavior would normally be counted unless the down power was planned 72 hours in advance. The circumstances of each situation are different and should be identified to the NRC in a FAQ so that a determination can be made concerning whether the power change should be counted.

Response The downpower that is described in this FAQ does count. The facility has not developed a specific procedure to proactively monitor for environmental conditions that would lead to sea grass intrusion, to direct proactive actions to take before the intrusion, and actions to take to mitigate an actual intrusion that are appropriate for the station and incorporate lessons learned. Development and use of a such a procedure in the future, instead of standing orders, may provide the basis for a future FAQ allowing excluding a downpower >20%
for this PI.

No change to PI guidance is needed.

ID 409

Posting Date 04/20/2006

Question **Appendix D (FitzPatrick)**

Frazil icing is a condition that is known to occur in northern climates, under certain environmental conditions involving clear nights, open water, and low air temperatures. Under these conditions the surface of the water will experience a super-cooling effect. The super-cooling allows the formation of small crystals of ice, frazil ice. Strong winds also play a part in the formation of frazil ice in lakes. The strong winds mix the super-cooled water and the entrained frazil crystals, which have little buoyancy, to the depths of the lake. The submerged frazil crystals can then form slushy irregular masses below the surface. The crystals will also adhere to any submerged surface regardless of shape that is less than 32°F.

In order to prevent the adherence of frazil ice crystals to the intake structure bars and ensure maintenance of the ultimate heat sink, the bars of the intake structure are continuously heated. Surveillance tests conducted before and after the event confirmed the operability of the intake structure deicing heaters. While heating assists in preventing formation of frazil ice crystals directly on the bars of the intake structure, the irregular slushy masses discussed above can be drawn to the intake structure in quantities that reduce flow to the intake canal. If the flow to the intake canal is restricted in this manner, then the circulating (lake) water flow must be reduced, to allow frazil ice formations to clear. This water flow reduction necessitates a reduction of reactor power.

The plant put procedural controls in place to monitor the potential for frazil ice formation during periods of high susceptibility. A surveillance test requires evaluating the potential for frazil ice formation during the winter months, when intake temperature is less than 33°F. In support of the surveillance test, the Chemistry Department developed a test procedure for assessing the potential for frazil ice formation. An abnormal operating procedure was developed to mitigate the consequences of an event should frazil icing reduce the flow through the intake structure. During the overnight hours between March 2, and March 3 the environmental conditions were conducive to the formation of frazil ice. Chemistry notified Operations that the potential for frazil icing was very high. Operators were briefed on this condition, the very high potential for frazil ice formation, and the need to closely monitor intake level.

When indications showed a lowering intake canal level with no other abnormalities indicated, operations entered the appropriate abnormal operating procedure and reduced power from 100% to approximately 30% so that circulating water pumps could be secured, thereby reducing flow through the intake structure heated bars, to slow the formation or accumulation of frazil ice and allow melting and break-up of the ice already formed.

As noted above NEI 99-02 Revision 3, in discussing downpowers that are initiated in response to environmental conditions states The circumstances of each situation are different and should be identified to the NRC in a FAQ so that a determination can be made concerning whether the power change should be counted.

Does the transient meet the conditions for the environmental exception to reporting Unplanned Power changes of greater than 20% RTP?

Response Yes, the downpower was caused by environmental conditions, beyond the control of the licensee, which could not be predicted greater than 72 hours in advance. Procedures, specific to frazil ice, were in place to address this expected condition. In lieu of additional FAQ submittals, this response may be applied by the licensee to future similar instances of frazil ice formation.

ID 399

Posting Date 07/21/2005

Question As defined in NEI 99-02, ***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 that 20% of full power to resolve. 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 condition, and prepare, review, and approve the necessary work orders, procedures, and necessary safety reviews, to effect a 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 planning that is performed between the discovery of the condition and the initiation of the power change.

Nine Mile Point Nuclear Station (NMPNS) Unit 1 performed a >20% downpower that commenced on 6/15/04 to swap power supplies on condensate pumps in order to exit a High Pressure Coolant Injection (HPCI) LCO action. The timeline leading up to the downpower is as follows:

- 6/7/04. Condensate Pump 13 is removed from service for planned maintenance to repair gland packing problems. Condensate Pump 13 is part of HPCI train #12. A 15 day LCO is entered for the HPCI train being inoperable.

- 6/10/04. During maintenance, it was determined that the existing pump was unusable. A contingency plan was implemented to replace the existing pump with an old rebuilt pump. A second contingency plan was started by plant personnel to swap out pump power supplies to make Condensate Pump 12 act as a

HPCI pump. This would allow the station to exit the LCO and complete pump repairs on a normal schedule. Swapping out power supplies required pump 12 to be removed from service which would require a planned downpower to 45% rated.

- 6/11/04. A Temporary Design Change Package was initiated to swap the HPCI power supplies.

- 6/13/04. The first contingency for installing a rebuilt pump was unsuccessful when the pump failed post-maintenance testing due to high running amps. The station then concentrated on implementing the second contingency plan.

- 6/15/04. The down-power to perform the second contingency plan began. The LCO was exited on 6/17/04.

The resident inspection staff questioned the off-normal condition that caused the power change. They considered the rebuilt pump PMT failure on 6/13/04 as the off-normal condition that resulted in the power change. Since the time from the PMT failure to the downpower was less that 72 hours, the resident inspection staff considered the downpower unplanned.

In evaluating this event for reporting under the NRC ROP PI process, the Licensee concluded that the down-power was planned. The basis for this position is as follows:

The initial off-normal condition was the degraded gland packing on the Condensate pump. This condition necessitated removal of the pump from service to implement repairs. The pump was removed from service and the appropriate Technical Specification LCO was entered on 6/7/04. It was this off-normal condition that ultimately led to the down-power that occurred on 6/15/04. Since the down-power was more that 72 hours after the corrective maintenance evolution was initiated, it was classified as planned.

Should the power change described above be counted in the ROP Performance Indicator for Unplanned Power Changes per 7,000 Critical?

Response No. The licensee started a second contingency plan to be used in the event that the first contingency plan was unsuccessful. To complete this second plan would require a down-power of greater than 20 percent. When the first contingency plan was unsuccessful, the second plan was implemented. The time between starting the second plan and performing the down-power was greater than 72 hours. Therefore the down-power was "planned."

ID 395

Posting Date 05/19/2005

Question On September 4, 2004, Oconee Unit 1 was shutdown to inspect selected sections of Heater Drain piping. Although this inspection was driven from an August 2004 pipe failure at the Mahima Nuclear Plant in Japan, detailed planning for the Unit 1 shutdown did not begin until September 2, less than 72 hours prior to the outage. However, meetings and discussions had been held days earlier which recognized the potential need to bring Unit 1 off line for the piping inspections. Since this shutdown was pro-active and not driven by an equipment failure, Duke dispatching requested the shutdown occur September 4 (a holiday weekend) instead of September 11 which was initially proposed by the site. The NEI 99-02 criteria for reporting power changes of greater than 20% is for discovered off-normal conditions that require a power change of greater than 20% to resolve. Is the power change described above considered an unplanned power change for performance indicator reporting?

Response No. Since the power reduction was requested for an earlier date by the load dispatcher, it does not count.

ID 389

Posting Date 05/19/2005

Question On June 23, 2004, condenser waterbox level and temperature readings on the Unit 1 and 2 main condensers indicated partial blockage of the waterbox intake debris filters. The cause was an influx of gracilaria, which is a marine grass found in the river water that is the circulating water intake supply to the plant. Subsequent backwashes of the debris filters were successful at restoring waterbox level and temperature readings to the normal band, except for the 2B-South waterbox, which is one of four waterboxes of the Unit 2 main condenser. An extended backwash was unsuccessful in restoring its readings back to normal.
Debris is removed prior to entering the circulating water intake bay by traveling screens with spray nozzles. The 2B-South debris filter is directly downstream from the 2D traveling screen. Investigation of this event found that the spray nozzles for the 2D traveling screen had more fouling than the other spray nozzles. The 2D traveling screen was able to adequately remove normal debris loading, but was not as effective as the other spray nozzles in removing the debris during the large influx of gracilaria.

A decision was made on June 24, 2004 to reduce power to about 53% and isolate the 2B-South waterbox to clean its debris filter. The decision to reduce power within 24 hours was based on several factors, such as reduced condenser efficiency, the potential for additional debris filter clogging, and a reduction in reactor water chemistry due to elevated condensate demineralizer resin temperatures. It was also based on input from work management, operations, and the load dispatcher. The 2B-South waterbox was successfully cleaned during the downpower and reactor power was restored to normal operating conditions.

This was an anticipated power change in response to expected conditions. Operating experience has shown that the plant is susceptible to large influxes of gracilaria when the salinity level in the river water is elevated. For example, gracilaria problems were correlated with high salinity levels in 2002, which led to high vulnerability conditions. In addition, during another influx of gracilaria, a downpower was required in August, 2001 to clean the 1A-South debris filter. In response to experience over the past 5 years with gracilaria and other intake canal debris, modifications are being implemented at the river water intake diversion structure, which is the first barrier for intake debris, to improve the debris removal capability.

In response to the influx of gracilaria, the plant implemented compensatory actions for a "High Vulnerability" condition in the intake canal. These actions include manning the diversion structure round-the-clock for manual debris removal, increasing screen wash pressure, and staging fire hoses at the traveling screens, if needed, to assist in removing debris. During the June 23 event, all four waterboxes on Unit 1 and three of four waterboxes on Unit 2 were managed within normal operating levels.

The power change was proceduralized. The plant operating procedure for circulating water directs a power reduction to isolate a waterbox and clean the debris filter if an abnormally high differential pressure exists after debris filter flushing has been completed.

The influx of gracilaria was not predictable greater than 72 hours in advance. Although the biology staff has found that high salinity levels in the river water make the conditions for a gracilaria release favorable, it is not possible to predict when an excessive influx will occur. The compensatory actions taken for a high vulnerability condition have usually been effective in preventing debris filter clogging.

Should this event be counted as an unplanned power change?

Response No. The increased accumulation of gracilaria in the river water was anticipated because of the high salinity levels in the river, but the timing of the graciliaria release into the intake canal could not be predicted greater than 72 hours in advance. In addition, the actions to be taken in response to the high salinity levels in the river water were proceduralized.

ID 383

Posting Date 04/28/2005

Question NEI 99-02 specifically requests an FAQ for this condition: Anticipated power changes greater than 20% in response to expected problems (such as accumulation of marine debris and biological contaminants in certain seasons) which are proceduralized but cannot be predicted greater than 72 hours in advance may not need to be counted if they are not reactive to the sudden discovery of off-normal conditions. The circumstances of each situation are different and should be identified to the NRC in an FAQ so that a determination can be made concerning whether the power change should be counted.

Event Description: On August 31, 2004, Unit 2 experienced a trip of the 2D Circulating Water Intake Pump (CWIP). This caused a reduction in condenser vacuum, which was mitigated by a 21% power reduction. The CWIP tripped due to a high differential pressure on the traveling screen, (i.e., a moving screen upstream of the pump intake that removes debris and marine growth.) Increased accumulation of debris and marine growth on the traveling screens is an expected condition during extreme lunar tides, as was the case on August 31. Although the timing and potential vulnerability of the lunar low tide was known, it was not possible to predict if, or when, an excessive influx of marine growth or debris would occur.

The plant was in a "high vulnerability" condition, meaning that conditions in the intake canal were more likely to challenge the traveling screens and CWIPs. The marine growth is a particular nuisance in the summer months during periods of lower tides. The increased canal bottom temperature during these periods causes organic debris to decay at a higher rate and tends to produce more suspended solids in the intake water. Plant operating experience includes several instances when traveling screens have experienced high differential pressures and CWIP trips. For example, LER 2-1999-006, "Automatic Reactor Shutdown Due to Condenser Low Vacuum Main Turbine Trip" documents a similar event. Mitigating actions have been taken, such as canal dredging; however, these changes must be compatible with state environmental water quality regulations. Therefore, changes to reduce traveling screen clogging, such as increasing the mesh sizing on traveling screens, are limited in their effectiveness.

On August 30, 2004, Unit 1 traveling screens received high differential pressure alarms. As a result, both units' traveling screens were placed in the "hand fast" position. The procedure for intake canal blockages includes steps for high vulnerability conditions, such as ensuring the traveling screens are operating in "hand fast" speed and reducing reactor power for a sustained high differential pressure. Both units' screens remained in this alignment throughout the event; however, the increase in the 2D screen differential pressure was too rapid to counteract with mitigating actions to prevent the pump trip.

Response This event does not need to be counted as an unplanned power change because the high vulnerability condition in the intake canal was being monitored, the response to the high vulnerability intake canal condition was proceduralized, and the rapid accumulation of debris was not predictable greater than 72 hours in advance.

ID 366

Posting Date 06/16/2004

Question During a scheduled refueling outage, the rotor was replaced on the 'C' low pressure turbine. During initial startup on October 27, 2003, with the plant stable at 17.7% reactor power, high vibrations were detected on the bearings associated with the replaced rotor. The turbine was tripped and shutdown, a troubleshooting team formed and a repair plan developed. In order to collect vibration data required to identify the optimum location for the placement of balancing weights, the repair plan called for the starting and phasing of the main turbine. With reactor power at 22.2%, the main generator breaker was closed at 18:32. After the collection of vibration data, the turbine was tripped at 20:37 and reactor power reduced to 1.1%. When the performance indicator data for the 4th quarter of 2003 was submitted, this reduction in power of 21.1% was not included in the Unplanned Power Changes per 7,000 Critical Hours Performance Indicator.

The NEI 99-02 criteria for reporting power changes of greater than 20% is for discovered off-normal conditions that require a power change of greater than 20% to resolve. Frequently, high vibrations and/or rubbing occur during startup following rotor replacement. As an expected condition rather than an off-normal condition, the associated reduction in power should not count as an unplanned power change.

Is the power change described above considered an unplanned power change for performance indicator reporting?

Response Yes, the power change is considered an unplanned power change for performance indicator reporting. Although not discussed in the proposed FAQ, during the May 27, 2004, ROP public meeting, the licensee stated that the plan was to gather vibration data at 30% reactor power. However, during the power ascension the turbine was tripped at 22.2% reactor power due to vibrations and power was reduced to 1.1%. The repair plan did not include procedural guidance to trip the turbine or reduce power due to turbine vibrations.

ID 365

Posting Date 05/27/2004

Question Frazil icing is a condition that is known to occur in northern climates, under certain environmental conditions involving clear nights, open water, and low air temperatures. Under these conditions the surface of the water will experience a super-cooling effect. The super-cooling allows the formation of small crystals of ice, frazil ice. Strong winds also play a part in the formation of frazil ice in lakes. The strong winds mix the super-cooled water and the entrained frazil crystals, which have little buoyancy, to the depths of the lake. The submerged frazil crystals can then form slushy irregular masses below the surface. The crystals will also adhere to any submerged surface regardless of shape that is less than 32°F.

In order to prevent the adherence of frazil ice crystals to the intake structure bars and ensure maintenance of the ultimate heat sink, the bars of the intake structure are continuously heated. Surveillance tests conducted before and after the event confirmed the operability of the intake structure deicing heaters. While heating assists in preventing formation of frazil ice crystals directly on the bars of the intake structure, the irregular slushy masses discussed above can be drawn to the intake structure in quantities that reduce flow to the intake canal. If the flow to the intake canal is restricted in this manner, then the circulating (lake) water flow must be reduced, to allow frazil ice formations to clear. This water flow reduction necessitates a reduction of reactor power.

The plant had previously put procedural controls in place to monitor the potential for frazil ice formation during periods of high susceptibility. A surveillance test requires evaluating the potential for frazil ice formation during the winter months, when intake temperature is less than 33°F. In support of the surveillance test, the Chemistry Department developed a test procedure for assessing the potential for frazil ice formation. An abnormal operating procedure was developed to mitigate the consequences of an event should frazil icing reduce the flow through the intake structure. During the overnight hours between February 14, and February 15, 2004 the environmental conditions were conducive to the formation of frazil ice. Chemistry notified Operations that the potential for frazil icing was very high. Operators were briefed on this condition, the very high potential for frazil ice formation, and the need to closely monitor intake level.

When indications showed a lowering intake canal level with no other abnormalities indicated, operations reduced power from 100% to approximately 30% per procedure so that circulating water pumps could be secured, thereby reducing flow through the intake structure heated bars, to slow the formation or accumulation of frazil ice and allow melting of the ice already formed.

NEI 99-02, in discussing downpowers that are initiated in response to environmental conditions states The circumstances of each situation are different and should be identified to the NRC in a FAQ so that a determination can be made concerning whether the power change should be counted.

Does the transient meet the conditions for the environmental exception to reporting Unplanned Power changes of greater than 20% RTP?

Response Yes, the downpower was caused by environmental conditions, beyond the control of the licensee, which could not be predicted greater than 72 hours in advance. Procedures were in place to address this expected condition.

ID 360

Posting Date 03/25/2004

Question 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.

On September 20, 2003, both units 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 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.

Should these shutdowns be counted as unplanned power reductions?

Response No. The shutdowns were initiated to address the impact of an unexpected external event that threatened equipment in the switchyard and as such do not need to be included as an unplanned power change. However, it is expected that the licensee would update procedures training, etc., to reflect the expected response in the event of similar meteorological conditions (i.e., high winds with minimal rain).

If these conditions are experienced in the future, they should be considered an expected problem, and any power change greater than 20% should be counted unless the actions to take in response to the condition are proceduralized, cannot be predicted greater than 72 hours in advance, and are not reactive to the sudden discovery of an off-normal condition.

ID 343

Posting Date 05/01/2003

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 criterion 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."

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 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.

ID 334

Posting Date 01/23/2003

Question The indicator counts changes in reactor power, greater than 20%, before 72 hours have elapsed following the discovery of an off-normal condition. The unit 2 experienced a power change greater than 20% in 2002 that was not included in the indicator. Discussion of the event follows. In February 2002, Unit 2 was returning to service after a scheduled refueling outage. During plant heat-up, a steam generator stop valve was drifting off the open detents while at normal operating pressure and temperature. This was a documented, long-standing condition for these types of valves during reactor start-ups, and identified in the corrective action program at 1600 hours on February 25, 2002. Preliminary evaluation of the condition concluded, based upon previous experience with these valves, that when power was increased, the valve would remain on the detents with lower steam pressure. The decision was made to continue with reactor start-up and the unit was placed online. It was recognized by plant personnel that should the condition not correct itself as anticipated, a downpower would be required to effect repairs to the valve. Additionally, during this period, the valve was monitored by plant personnel and a problem solving team was formed to establish contingency plans should the condition not correct itself. On February 28, with reactor power at 28%, the stop valve was still drifting off the open detents. The decision was made to remove the generator from service and reduce reactor power to 2% to adjust the valve packing assembly. That decision was based on further evaluation by the problem solving team of the possible causes for the valve drifting off the open detents. At 2033 hours on February 28, Unit 2 commenced the power reduction to 2 % reactor power. When the unit was returned to service after the packing adjustment, the valve remained on the open detents. The event was not counted as an unplanned power change since 76.5 hours had elapsed from the discovery (as documented in the corrective action program) of the valve drifting off the open detents to the commencement of the power reduction. The resident inspection staff questions the off-normal condition that caused the power change. Since no plans were made to remove the unit from service for repairs but to continue the start-up with the expectation that the condition would correct itself at higher power levels based on previous experience, the decision to downpower the unit to adjust the packing assembly when the condition did not correct itself constituted a different off-normal condition. Should the power change described above be counted in the Unplanned Power Changes per 7,000 Critical Hours Performance Indicator?

Response No, this indicator captures changes in reactor power that are identified following the discovery of an off-normal condition. Although the identified condition had occurred previously in plant history, and had corrected itself after power ascension, the management team recognized that this may not always occur. As discussed above, during this period the valve was monitored by plant personnel and a problem solving team was formed to evaluate options and establish contingency plans should the condition not correct itself. Once it was identified that the condition would not correct itself, a power reduction was completed to affect repairs. The power reduction was commenced greater than 72 hours after the condition was identified. This is consistent with the guidance of NEI 99-02, Rev. 2.

ID 329

Posting Date 12/12/2002

Question NEI 99-02 states that unplanned power changes include runbacks and power oscillations greater than 20% of full power. Under what circumstances does a power oscillation that results in an unplanned power decrease of greater than 20% followed by an unplanned power increase of 20% count as one PI event versus two PI events? For example: During a maintenance activity an operator mistakenly opens the wrong breaker which supplies power to the recirculation pump controller. Recirculation flow decreases resulting in a power decrease of greater than 20% of full power. The operator, hearing an audible alarm, suspects the alarm may have been caused by the activity and closes the breaker resulting in a power increase of greater than 20% full power.

Response Both transients in the example should be counted. There were two errors: (1) opening the wrong breaker and (2) reclosing the breaker without establishing the correct plant conditions for restarting the pump. If the pump had been restored per approved procedures only the first transient would be counted.

ID 320

Posting Date 09/26/2002

Question NEI 99-02, Rev 2, states that anticipated power changes greater than 20% in response to expected problems (such as accumulation of marine debris and biological contaminants in certain seasons) which are proceduralized but cannot be predicted greater than 72 hours in advance may not need to be counted if they are not reactive to the sudden discovery of off-normal conditions. The circumstances of each situation are different and should be identified to the NRC in a FAQ so that a determination can be made concerning whether the power change should be counted.

NEI 99-02, Rev 2, does not discuss whether the power changes associated with these FAQs should be counted while awaiting disposition. Is it satisfactory to state in the comment field that a FAQ has been submitted, and not to include the power changes in the PI calculation?

Response Yes. The comment field should be annotated to state that a FAQ has been submitted. The licensee and the NRC should work expeditiously and cooperatively, sharing concerns, questions, and data, in order that the issue can be resolved quickly. However, if the issue is not resolved by the time the quarterly report is due, and the licensee is confident that this exclusion applies, it is not necessary to include these power changes in the submitted data. Conversely, if the licensee is not confident that this exclusion applies, the unplanned power change(s) should be counted. In either case, the report can be amended, if required, at a later date.

ID 319

Posting Date 09/26/2002

Question At approximately 2243 hours on September 24, 2001 the number 2 Station Power Transformer in the Switchyard experienced an electrical fault on one of its associated surge arresters. The failure of this surge arrester resulted in the loss of both the number 2 and 4 main station power transformers and station power transformers 12, 14, 22 and 23. As a result, each unit lost three (Unit 1 lost 11B, 12B, 13B) of the six condenser circulating pumps. Additionally, unit 1 lost power to its circulating water traveling screens, as well as the sensing instrumentation for the differential pressure across the traveling screens. Upon loss of power to the sensor, the screen delta p indication in the Control Room shows screen delta p as being in the acceptable range, regardless of actual screen delta p. With only three of six circulating water pumps operating per unit, both units reduced electrical load to maintain main condenser vacuum. Following the completion of the power reduction, unit 1 personnel restored electrical power to the Unit 1 circulating water bus and the circulating water traveling screens. This occurred approximately 1 hour after the electrical fault. Because of the loss of power to the traveling screens, detritus buildup (detritus levels were between 1400 and 1500 Kg/10E6 cubic meters) caused a high differential pressure on the remaining screens. Shortly after the power was restored to the traveling screens, one (13A) of the three remaining circulating water pumps tripped due to high differential pressure across its associated traveling screen. Because of the loss of power to the sensing instrumentation, this condition was not detected prior to restoring the power. As a result of this additional loss of a circulating water pump and the resultant decrease in condenser vacuum, Unit 1 licensed control room operators initiated a manual trip in accordance with the guidance provided in the abnormal operating procedure at 2351, on September 24. This event was similar to previous loss of station power transformer events that occurred in June and July of 2001. In all three of the events, each unit lost three circulators, and one of the two units lost all six traveling screens (in June and July Unit 2 lost the traveling screens), their controls, indications, and the screen wash pumps. In addition, all three events resulted in a power reduction for both units. In both the June and July events, it took longer (1.75 to 6.25 hours) to restore power to the circulators than it did in the September event. The June and July events did not result in the loss of an additional circulator after power was restored because the detritus levels were lower (in the 400s). Therefore, a plant scram was avoided.

Unit 2 circulating water traveling screens were unaffected by the loss of the 2 SPT, therefore the power reduction was sufficient to maintain main condenser vacuum. Does this event meet the criterion in NEI 99-02 that states "Off-normal conditions that begin with one or more power reductions and end with an unplanned reactor trip are counted in the unplanned reactor scram indicator only." Or are the causes of the downpower and the scram sufficiently different that an unplanned power change and an unplanned scram must both be counted.

Response The causes of the downpower and the scram are different. The loss of the station power transformer caused the downpower. The operators failure to anticipate the effects of power restoration led to the loss of the fourth circulator and the scram. Therefore both an unplanned power change and an unplanned scram should be counted.

ID 311

Posting Date 05/22/2002

Question Question:Plant surveillance procedure 3-OSP-090.2, *Main Electrical Generator Hydrogen Leakage Calculation* is performed on a weekly basis. Data is gathered on the weekend by operations. Calculations and tracking are performed by the System Engineer each Monday morning. During the past 17 months, hydrogen leakage on the Unit 3 main generator ranged about 800 to 1300 cu ft/day. This leakage was due primarily to a known bad hydrogen seal on the north end of the generator. This hydrogen was being safely discharged through the seal oil vapor extractor vent. Repair of this leak was planned for the upcoming refueling outage.

Hydrogen consumption by the Unit 3 main generator during the weekend of 07/07/01 increased significantly. The calculated consumption per 3-OSP-090.2 was 1665 cubic feet per day. This is in excess of the typical Westinghouse generator leakage and a sizeable increase of the trend for Unit 3. On 07/11/01 the system

engineer initiated Condition Report (CR01-1364), and a concerted effort began to identify the source of the leak.

During the week of 07/11/01, the Engineering Systems Manager and the System Engineer briefed the Plant Manger on the leakage. During this meeting the possibility of a unit shutdown to effect repairs was recognized and discussed. Since no administrative limit on hydrogen leakage had been previously established, the Plant Manager established criteria for unit shutdown. The criteria was:

(1) Leakage not attributed to the seal becoming greater than 2000 cu ft/day (approx. 3000 cu ft/day total) AND there was evidence of hydrogen pooling in any area around the generator in excess of 50% LEL,

(2) an unisolable leak that could not be repaired on-line

(3) a leak that was rapidly degrading.

The decision was made to pursue on-line repairs, as long as conditions permitted and to shutdown if on-line repairs could not be performed.

From 07/11/01 through 07/28/01 extensive system checking was performed by Engineering and Maintenance personnel. All valves and devices were inspected sniffed and snooped. Additionally, accessible piping was checked hand over hand. The known leak via the seal oil system was re-quantified and ruled out as the source of the new leakage. During this period, several minor leaks were identified and isolated or repaired.

The Main Generator leakage data gathered on 07/28/01 showed leakage on Unit 3 had increased to 2091 cu ft/day. Air movers were installed to draw off hydrogen gases from areas around the generator. The generator skirt access plates, doors, etc. on the turbine deck were removed/opened to sample that space and prevent hydrogen pooling (the turbine building is an open air design). No evidence of hydrogen pooling was found. System inspections continued and a cap was installed down stream of valve 3-100-23-1 to isolate a minor leak there. Scaffolding was ordered built to access the belly of the generator so that the penetrations could be inspected.

On Saturday, 08/04/01 the hydrogen leakage data showed a leak rate of 3015 cu ft/day. The hydrogen dryer was isolated. No evidence of hydrogen pooling was found.

On Monday 08/06/01 the hydrogen leakage data showed a leak rate of 2840 cu ft/day, only a slight decrease. The Plant Manager ordered daily calculations and contingency plans for shutdown repairs if the leak was found to be unisolable. Scaffolding was in place under the south end of the generator and an extensive inspection of the generator system was performed, but no additional leaks were found. The presence of hydrogen was measured in that vicinity at 8% LEL, but no source could be pinpointed.

On Tuesday 08/07/01, operations began methodical monitoring of the leak rate by taking data readings every 6 hours. Additional scaffolding was erected beneath the center section of the generator to allow leakage checks of the hydrogen system piping penetrations. Thermographic images were taken of the area under the generator, but no evidence of leaks were found.

On Wednesday 08/08/01, the leak rate was calculated to be 3001 cu ft/day, the scaffolding extension for the full length of the generator was completed. New high sensitivity hydrogen detection equipment was received and put to work. Engineering and Maintenance continued testing for leaks and evidence of pooling. The Isophase ducts were sampled but no hydrogen found. Each generator penetration was snooped and sniffed. The length of each pressurized hydrogen line, paying particular attention to welds and valves, was sniffed and snooped. Some additional minor leaks were found.

Engineering personnel then found a large leak on the generator lead box. Cracking was evident between the bottom flange and vertical member weld on the southwest corner. Investigation by plant personnel determined that a fillet weld at the base of the collar of the main lead box assembly was cracked. The crack appeared to be several inches in length and seemed to go around the lower southwest corner of the box. To ensure safety, additional air movers were installed to dissipate the hydrogen gas.

Engineering personnel were directed by plant management to develop two specific repair methods:

(A) a temporary repair method to be worked on-line and

(B) (as a parallel effort) a repair method to be performed off-line.

Plan A, the on-line repair method, proposed using strong backs and sealing material, mechanically wedged or clamped against the crack and then filled with Fermanite. Plan B, the off-line repair method, proposed a weld overlay. Additional scaffolding was erected to safely reach the lead box to support either activity.

On Thursday 08/09/01, the leak rate was calculated to be 4421 cu ft/day. Upon closer examination of the crack, engineering determined that Plan A, the on-line repair method, was not viable. Plan B, which used welding, was judged the only effective repair method. Plan B required the generator to be purged of hydrogen and depressurized maintaining a CO2 cover gas.

On Friday 08/10/01 at about 2:30PM, Unit 3 was brought to mode 2 in an orderly fashion and the generator purged with CO2. The unit was brought down to mode 2 at a rate of about 10% per hour, using the normal operating procedure, 3-GOP-103, "Power Operation to Hot Standby. " The "Fast Load Reduction Procedure, " 3-ONOP-100, was never entered. The weld was repaired using the weld overlay procedure outlined in CR01-1364 Interim Disposition #1.

The main generator hydrogen system is described in Section 10.1 of the UFSAR. The UFSAR does not reference any allowable leak rates and there are no Technical Specifications with regard to hydrogen leakage. There are no

adverse effects on the Turkey Point FSAR and Technical Specifications. The concern for hydrogen leakage is in regard to the potential for adverse personnel and industrial safety. Measures (forced ventilation) were taken to maintain safety; therefore, shutdown for repairs was a conservative and prudent action. The decision to shutdown was not based on operability or safety concerns, but rather on establishing the necessary conditions to facilitate repairs.

In accordance with NEI-99-02, 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 Unit 3, was initially identified on July 11, 2001 (30 days prior to the actual shutdown). Moreover, the possibility of the need to shutdown for repairs was recognized just days later and limits were established to trigger that action (a plan established). 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?

Response 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.

ID 306

Posting Date 04/25/2002

Question This FAQ is submitted based on the statement in NEI 99-02 Rev 1, page 17, lines 28 - 33: "Anticipated power changes greater than 20% in response to expected problems (such as accumulation of marine debris and biological contaminants in certain seasons) which are proceduralized but cannot be predicted greater that 72 hours in advance may not need to be counted if they are not reactive to the sudden discovery of off-normal conditions. The circumstances of each situation are different and should be identified to the NRC in a FAQ so that a determination can be made concerning whether the power change should be counted."

The water conditions of Lake Ontario have improved over the years. One of these improvements has been the increased clarity of the water. This increased clarity allows the sun light to penetrate much deeper in all areas of the lake, thus encouraging aquatic growth, such as lake grass. The spring and summer of 2001 have been storm-free on most of Lake Ontario causing little disturbance and turnover of the lake water.

On July 26, 2001, a significant change in the weather and lake environment caused the station engineers monitoring the condenser efficiency to check the condenser parameters. Due to the influx of lake grass, the delta-T across potions of the main condenser had increased, but remained within environmental release limits. Due to micro-fouling (zebra mussels, silt) in the past, the station is sensitive to lake conditions, however, prior to this event, the station had not experienced condenser fouling due to lake grass. In addition, the need to check condenser efficiency with no adverse indication is not proceduralized.

The delta-T across the affected condenser side improved over the next couple of days as the weather and the lake conditions returned to more normal and the lake grass washed itself from the condenser. However, a down power was needed to clean the main condenser. A decision was made to clean the main condenser when the electric grid loading allowed for it. Discussion with load control dispatchers determined that July 28, 2001, would be the most opportune and economic time to reduce load. The main condenser was cleaned that Saturday morning. At no time between discovery and condenser cleaning did any condenser parameter require a load adjustment other than to improve efficiency as a result of the lake grass influx. Is this greater than 20% power change considered an unplanned power change?

Response No The influx of lake grass had not caused condenser fouling in the past and was therefore an unanticipated event. The licensee is expected to take reasonable steps to prevent intrusions of lake grass from causing power reductions in the future

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ID 305

Posting Date 03/21/2002

Question Conditions arise that would require unit shutdown, however an NOED is granted that allows continued operation before power is reduced greater than 20%. Should the event be reported as an unplanned change in reactor power under the Unplanned Power Changes per 7,000 Critical Hours performance indicator?

Response No, the condition should not be counted as an unplanned power change because no actual change in power occurred on the units involved. A comment should be made that the NRC had granted an NOED during the quarter, which, if not granted, may have resulted in an unplanned power change.

ID 304

Posting Date 03/21/2002

Question **Appendix D Quad Cities**

1) At Quad Cities, load reductions in excess of 20% during hot weather are sometimes necessary if the limits of the NPDES Permit limit would be exceeded. Actual initiation of a power change is not predictable 72 hrs in advance, as actions are not taken until temperatures actually reach predefined levels. Would these power changes be counted?

2) Power reductions are sometimes necessary during summer hot weather and/or lowered river level conditions

when conducting standard condenser flow reversal evolutions. The load reduction timing is not predictable 72 hrs in advance as the accumulation of Mississippi River debris/silt drives the actual initiation of each evolution. The main condenser system design allows for cleaning by flow reversal, which is procedurally controlled to assure sufficient vacuum is maintained. It is sometimes necessary, due to high inlet temperatures, to reduce power more than 20% to meet procedural requirements during the flow reversal evolution. These conditions are similar to those previously described in FAQ 158. Would these power changes be counted for this indicator?

Response 1) No.
2) No. Power changes in excess of 20% for the purposes of condenser flow reversal are not counted as an unplanned power change.

ID 300

Posting Date 01/25/2002

Question On 4/19/01 at 1917 hours, a DC bus ground was traced to the breaker for a heater drain pump at BVPS Unit 2. This was verified via a troubleshooting plan at 1152 hours on 4/21/01. The Unit 2 NSS had contacted Conversion Economics and stated that BVPS-2 desired a window to perform a power reduction to approximately 40% in order to perform a breaker swap-out on the "A" Heater Drain Pump due to a DC ground. The window could be Saturday (4/21/01) or Sunday (4/22/01) or the following weekend, and that BVPS-2 could "load follow" in place of another FE plant since the system demand was projected to be low over these weekends. At 1323 hours on 4/21/01, it was decided by Conversion Economics that BVPS-2 would begin to load follow at 2200 hours on 4/21/01 to an output of approximately 40%. Return to full power was set to begin at 0700 hours on 4/22/01. Based on the above, this reduction was considered to be "load following", and therefore, the reduction was NOT counted against this PI value in April 2001. A load reduction within the 72 hours following identification of the specific equipment problem was not required, nor specifically requested by the plant. The date and time of the load reduction was left to the discretion of the load dispatcher. The NRC Resident Inspector questioned whether this event should have been counted in the PI for unplanned power changes.

QUESTION: The plant has an equipment malfunction and initiates a call to the system load dispatcher requesting a window to perform a power reduction to facilitate repairs. The plant informs the load dispatcher that the window does not need to be within 72 hours of the equipment problem. However, the load dispatcher subsequently responds with a load reduction window that occurs within 72 hours of the equipment problem. Does this qualify the load reduction as being "directed by the load dispatcher" and therefore not reportable under this PI?

Response No. The power change was not under "normal operating conditions due to load demand and economic reasons," nor was it "for grid stability or nuclear plant safety concerns arising from external events outside the control of the nuclear unit." It was "due to equipment failures that are under the control of the nuclear unit." Because the power was reduced in less than 72 hours, the downpower counts. (See NEI 99-02 Rev 1 page 17 lines 37 to 41. Rev 2 page 20 lines 37 to 41)

ID 295

Posting Date 12/13/2001

Question **Appendix D - Point Beach Units 1 and 2**

On June 27th, Point Beach Unit 2 was manually scrammed, in accordance with Abnormal Operating Procedure AOP 13A, "Circulating Water System Malfunction," and power was reduced on Point Beach Unit 1 by greater than 20% (from 100% to 79%) due to reduced water level in the pump bay attributable to an influx of small forage fish (alewives). The large influx of fish created a high differential water level across the traveling screens and ultimately failure of shear pins for the screen drive system, leading to a rapid drop in bay level. The plant knows when the alewife spawning and hatching seasons occur and the effects of Lake Michigan temperature fluctuations on the route of alewife schools. It was aware of the presence of large schools at other Lake Michigan plants this spring and discussed those events and the potential of them occurring at Point Beach at the morning staff meetings. During the thirty years of plant operation, there have been a few instances where a large number of fish entered the plant circ water system. High alewife populations coupled with seasonal variations, lake conditions and wind conditions created the situation that resulted in the down power on June 27th. Point Beach staff believe that these are uncontrollable environmental conditions. Plant procedures are in place which direct actions when the water level in the pump bay decreases. However, it is not possible to predict the exact time of an influx of schooling fish nor the massive population of fish that arrived in the pump bay. Page 17 of NEI 99-02 Revision 1 states, "Anticipated power changes greater than 20% in response to expected problems (such as accumulation of marine debris and biological contaminants in certain seasons) which are proceduralized but cannot be predicted greater than 72 hours in advance may not need to be counted if they are not reactive to the sudden discovery of off-normal conditions." Would this situation count as an unplanned power change?

Response No. The influx of alewives was expected as evidenced by the discussion of events at other plants on Lake Michigan but was not predictable greater than 72 hours in advance due to the variables involved. Large schools of alewives are a result of environmental and aquatic conditions that occur in certain seasons. The response to the drop in bay level is proceduralized.

ID 294

Posting Date 12/13/2001

Question This spring the above water portion of the circulating water intake structure was removed. This action was required by two federal agencies due to the issue of the intake structure attracting, inadvertently trapping and leading to the demise of double crested cormorants (a protected migratory bird species). Anticipating the possibility of fouling, contingency work orders were created on April 3 before the intake demolition started for cleaning of the main condenser water boxes and condensate coolers. These activities anticipated the necessity for reductions in power by greater than 20% and prescribed plant operating criteria that would necessitate initiation of these cleaning activities in response to accumulation of marine debris. However, the exact dates when these power reductions and cleaning activities would occur could not be predicted greater than 72 hours in advance.
Power was reduced by greater than 20% for cleaning attributable to the accumulation of marine debris due to the ongoing intake structure activities on May 19th and May 25th for Unit 2 and Unit 1, respectively. In both cases, the rapid deterioration in the monitored plant parameters dictated power reductions and cleaning in less than 72 hours from the onset of the conditions.

In addition, a Tech Spec surveillance required main turbine stop and governor valve with turbine trip test, requiring a reduction in power to about 65%, had been scheduled approximately 12 months in advance to occur at a later date. Since Unit 2 required a load reduction to 50% due to marine fouling for water box cleaning, the Tech Spec surveillance was moved up to also take place during that power reduction.

Would any of these power changes in excess of 20% be counted for this indicator?

Response No. As discussed on p. 17 of NEI 99-02 Revision 1, if the power reductions were anticipated in response to expected problems (such as accumulation of marine debris and biological contaminants in certain season), a part of a contingency plan and not reactive to the sudden discovery of off normal conditions, they would not count. The planned maintenance power reduction to 65% would still be considered planned since it was planned greater than 72 hours in advance of its occurrence.

ID 277

Posting Date 07/12/2001

Question In February 2000, a leak was identified in main generator hydrogen cooler No. 34. At that time the leak rate was considered low enough for continued plant operation in accordance with Main Generator Gas System Operating Procedure (SOP-TG-001). Development of an Action Plan and outage schedule was initiated, daily trending of the hydrogen leakage rate was initiated, and plans for repair formulated. By the end of February 2000, an outage schedule was developed, Work Requests planned, material identified and orders placed. The schedule and work package was set aside for use if it became necessary to effect repairs prior to Refueling Outage 11 (scheduled for April 2001). In October 2000, the hydrogen leak rate increased (exceeded approximately 500 cu ft per day) and in accordance with the procedure additional monitoring via a special log was initiated. The approved Action Plan recommended that hydrogen coolers No. 33 and 34 be replaced with available spares. The leak continued to increase and after a maintenance shutdown October 25, the leakage increased to 843 cu ft per day by November 1. By the beginning of December the leak had increased to approximately 1200 cu ft per day and on December 18, the hydrogen leak rate increased to 2054 cu-ft per day. After assessing the condition, plant management decided to shut down the plant and perform the repairs as detailed in the outage schedule based on holiday resource scheduling. On December 19, the plant was shut down prior to reaching the procedural limitation of 4000 cu-ft per day which would have required an operability determination. This limitation is also less than the leakage specification specified by the vendor for continued operation. The 4000 cu-ft per day was considered a threshold for re-evaluation of the condition as required by the procedure. Repairs made and the unit returned to service close to the original outage schedule. This forced outage was evaluated for determining if it was applicable under the classification rules for an unplanned outage. In accordance with the guidelines of NEI-99-02, if the outage was planned more than 72 hours in advance, the outage could be classified as planned. Since the off-normal condition (leak) was identified in February and planning developed, although not all details completed, the shutdown met the criteria of identifying and planning 72 hours prior to the shutdown, and it was classified as a "planned" shutdown. The additional clarification in NEI-99-02, under FAQ No. 6 reinforced that determination. The shutdown was planned and per the examples in NEI-99-02, the time period between discovery of the off-normal condition exceeded 72 hours allowing assessment of plant conditions, preparation and review in anticipation of an orderly power reduction and shutdown. Does this event qualify as a unplanned shutdown?

Response No, the degraded condition was identified in February 2000, and an Action Plan was developed to address the condition, including a outage schedule, Work Request, material identification and procurement. Therefore, the degraded condition was identified and planning had been performed more than 72 hours prior to the initiation of plant shutdown. 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. The December leak rate did not exceed procedural limits requiring assessment of operability and plant shutdown and did not require a rapid response.

ID 274

Posting Date 05/31/2001

Question **Appendix D: Diablo Canyon**

The response to PI FAQ #158 states "Anticipatory power changes greater than 20% in response to expected problems (such as accumulation of marine debris and biological contaminants in certain seasons) which are proceduralized but cannot be predicted greater than 72 hours in advance may not need to be counted if they are not reactive to the sudden discovery of off-normal conditions."

Due to its location on the Pacific coast, Diablo Canyon is subject to kelp/debris intrusion at the circulating water intake structure under extreme storm conditions. If the rate of debris intrusion is sufficiently high, the traveling screens at the intake of the main condenser circulating water pumps (CWPs) become overwhelmed. This results in high differential pressure across the screens and necessitates a shutdown of the affected CWP(s) to prevent damage to the screens.To minimize the challenge to the plant should a shutdown of the CWP(s) be necessary in order to protect the circulating water screens, the following operating strategy has been adopted:·

-- If a storm of sufficient intensity is predicted, reactor power is procedurally curtailed to 50% in anticipation of the potential need to shut down one of the two operating CWPs. Although the plant could remain at 100% power, this anticipatory action is taken to avoid a reactor trip in the event that intake conditions necessitate securing a CWP. One CWP is fully capable of supporting plant operation at 50% power.·

-- If one CWP must be secured based on adverse traveling screen/condenser differential pressure, the procedure directs operators to immediately reduce power to less than 25% in anticipation of the potential need to secure the remaining CWP. Although plant operation at 50% power could continue indefinitely with one CWP, this anticipatory action is taken to avoid a reactor trip in the event that intake conditions necessitate securing the remaining CWP. Reactor shutdown below 25% power is within the capability of the control rods, being driven in at the maximum rate, in conjunction with operation of the atmospheric dump valves.

-- Should traveling screen differential pressure remain high and cavitation of the remaining CWP is imminent/occurring, the CWP is shutdown and a controlled reactor shutdown is initiated. Based on anticipatory actions taken as described above, it is expected that a reactor trip would be avoided under these circumstances.

How should each of the above power reductions (i.e., 100% to 50%, 50% to 25%, and 25% to reactor shutdown) count under the Unplanned Power Changes PI?

Response Anticipatory power reductions, from 100% to 50% and from 50% to less than 25%, that result from high swells and ocean debris are proceduralized and cannot be predicted 72 hours in advance. Neither of these anticipatory power reductions would count under the Unplanned Power Changes PI. However, a power shutdown from less than 25% that is initiated on loss of the main condenser (i.e., shutdown of the only running CWP) would count as an unplanned power change since such a reduction is forced and can therefore not be considered anticipatory.

ID 270

Posting Date 05/31/2001

Question If a plant chooses to correct a deficiency less than 72 hours following discovery (a steam leak or other condition) and reduces plant power to limit radiation exposure (ALARA) and this reduction in power (>20%) is not required by the license bases would this reduction be counted?

Response If the ALARA program determines that a power reduction of >20% is appropriate to conduct the maintenance/ repair, and the downpower is conducted in less than 72 hours from discovery, the downpower would count.

ID 244

Posting Date 01/10/2001

Question FAQ 6 describes a situation where degraded equipment conditions are monitored and plans are made for repairs. The monitoring continues beyond 72 hours from the problem identification until an administratively established limit is achieved. FAQ 6 indicates this would not be counted in the unplanned power change indicator. Similarly we have a situation of known potential degradation, however, it involves multiple equipment components. Specifically cooling tower components that may require power reductions of >20% power to repair the degraded condition(s). There is a monitoring program established that identifies off-normal conditions as well as establishing administrative limits for the components at which time a plant shutdown should be initiated. If the time period between discovery of an off-normal condition (identification of specific degraded component) and the power reduction exceeds 72 hours until the administratively established limit is reached, does this count as an unplanned power change

Response No. Provided the time period between the discovery of an off-normal condition of the specific component (that would require a power reduction upon reaching the administrative limits) and the power reduction exceeds 72 hours for each degradation occurrence.

ID 237

Posting Date 01/10/2001

Question You have a slow leak on a feedwater pump and a work request is initiated and placed on the 12 week schedule, then after 72 hours passes the leakage increases, but the work package is still applicable. You immediately decrease power to fix the pump. Is this considered an unplanned power change since you had a work package written and there was greater than 72 hours?

Response The event would count as an Unplanned Power Change. Power changes caused by or in response to off-normal events during the course of a pre-planned activity, count as unplanned power changes when a determination is made that the off-normal events necessitated a course of action that was outside contingency planning in place for the pre-planned activities. In these instances, the off-normal events cause, in effect, an exiting of the preplanned course of action and any power changes that occur following the exit of the plan are counted toward the performance indicator. Minor modifications to a planned activity in response to events are not considered unplanned power changes and are not counted toward the performance indicator.

ID 231

Posting Date 10/31/2000

Question This FAQ raises a question regarding the proper interpretation of the wording of this PI. NEI 99-02 states the purpose of this PI as: This indicator monitors the number of unplanned power changes (excluding scrams) that could have, under other plant conditions, challenged safety functions. Our plant planned a sequence of power changes and equipment manipulations to deal with a secondary chemistry problem. The plan was ready >72 hours in advance, and a written schedule existed. During execution of the plan, an additional equipment problem was discovered, but plant management chose to continue with the planned sequence of power changes, and to address the emergent equipment issue later in the planned outage. Had it occurred by itself, the equipment problem may have required a power change in excess of 20%. However, the problem did not cause departure from the already planned and scheduled activities, and did not cause urgent response from Operations staff to mitigate the equipment problem. There were no reactor safety implications. Consistent with the intent of the PI, we believe this event should not be counted against this PI.
However, part of the PI definition on page 18 of NEI 99-02 states that Unplanned changes in reactor power are changes in reactor power that are initiated in 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% full power to resolve. This wording could be viewed in two ways:

* This was a newly emergent off-normal condition that, by procedure, would have required the plant to reduce power if the condition were not fixed, it should be counted whether or not the power reduction was already planned and scheduled.

Or

* The emergent condition was not what initially caused the planned reduction in power, but was simply a secondary reason to proceed with the existing plan, the condition did not result in a change in power level greater than 20%.

Should the sequence of power changes be counted as an unplanned power change?

Response No. This sequence of power changes would not count.

ID 228

Posting Date 10/31/2000

Question The licensee reduced power on both units to support grid stability in response to a fault on off?site transmission line 15616. Each of the licensees two operating units are supplied from two 345 kilovolt (kV) lines. Line 15616, which supplies Unit 1 , was lost as a result of a static line failure. The power reduction was requested by the system load dispatcher in accordance with System Planning Operating Guide (SPOG) 1-3-F-1, Station Operating Guidelines, Revision 1, to allow disabling the Unit 1 turbine generator trip scheme while line 15616 was out of service. With line 15616 out of service, a fault on the second line supplying Unit 1 (line 15501 from) would cause a Unit 1 turbine trip. The turbine trip would then cause a reactor trip (if reactor power is greater than the P?8 interlock setpoint of 32.1%). The turbine trip is intended to prevent overloading remaining grid circuits, causing the grid to become unstable. It is not a Reactor Protection System function. Reducing power and disabling the Unit 1 turbine trip scheme would prevent Unit 1 from tripping if line 15501 was faulted or lost. There were no on?site problems associated with the loss of the transmission line. The first paragraph of SPOG 1?3?F?1 states that it is not necessary to take any corrective measures for stability for the outage of any single line provided that the protection system is normal. However, it may be desirable to disable the unit trip scheme(s) during single line outages. The power reductions requested by the load dispatcher (just over 20%) met the procedurally recommended output limitations for the station with line 15616 out of service with the stability trip scheme disabled.
Does this situation count?

Response No. In the situation described, the power reduction would not count. The exception from counting unplanned power changes when directed by the load dispatcher is intended to exclude power changes directed by the load dispatcher under normal operating conditions due to load demand and economic reasons, and for grid stability or nuclear plant safety concerns arising from external events outside the control of the nuclear unit. However, power reductions due to equipment failures that are under the control of the nuclear unit are included in this indicator.

ID 227

Posting Date 10/31/2000

Question Regarding the Unplanned power change PI, I have the following questions:
1. Is the 20% full power intended to be 20% of 100% power, or 20% of the maximum allowed power for a particular unit, say 97% [(.2)(.97)= 19%]

2. If an unplanned transient occurs which is greater than 20%, the operators stabilize the plant briefly and then cause a transient greater than 20% in the opposite direction, does that count as 2 hits against the PI?

3. For calculating the change in power, should secondary power data be used, nuclear instruments or which ever is more accurate?

Response 1. It is intended to be 20% of 100%.

2. In general, yes, however the specific scenario needs to be evaluated.

3. Licensees should use the power indication that is used to control the plant at the time of the transient.

ID 166

Posting Date 05/02/2000

Question Concerning Unplanned Power Changes per 7,000 Critical Hours, does the 72 hour period apply to situations where power reductions are required to conduct expected rod pattern adjustments? A specific example involves a reactor start-up and power ascension following a scram. It is expected that the subsequent startup will probably require a rod pattern adjustment after achieving 100% power. To conduct the adjustment after achieving 100% power would require a power reduction potentially greater than 20%. If this situation occurs in less than a 72 hour period (time frame from the scram to the > 20% power reduction following return to power operation) does this count as an unplanned power change?

Response This indicator monitors changes in reactor power that are initiated following the discovery of an off-normal condition. The example described would not be counted in the unplanned power changes indicator provided the condition is expected.

ID 158

Posting Date 04/01/2000

Question Power changes (reductions) in excess of 20%, while not routinely initiated, are not uncommon during summer hot weather conditions when conducting the standard condenser backwashing evolution for our once though, salt water cooled plant. While it is known that backwashing will be performed multiple times a week during warm weather months (and less frequently during colder months), the specific timing of any individual backwash is not predictable 72 hours in advance as the accumulation of marine debris and the growth rate of biological contaminants drives the actual initiation of each evolution. The main condenser system was specifically designed to allow periodic cleaning by backwash which is procedurally controlled to assure sufficient vacuum is maintained. It is sometimes necessary, due to high inlet temperatures, to reduce power more than 20% to meet procedural requirements during the backwash evolution. Similarly load reductions during very hot weather are sometimes necessary if condenser discharge temperatures approach our NPDES Permit limit. Actual initiation of a power change is not predictable 72 hours in advance as actions are not taken until temperatures actually reach predefined levels. Would power changes in excess of 20% driven by either of these causes be counted for this indicator?

Response No. If they were anticipated and planned evolutions and not reactive to the sudden discovery of off normal conditions they would not count. The circumstances of each situation are different and should be identified to the NRC so that a determination can be made concerning whether a power change is counted.

ID 157

Posting Date 04/01/2000

Question Power was reduced on three consecutive days for condenser cleaning, in accordance with established contingency plans for zebra mussel fouling of the main condenser. Should these power reductions count as unplanned power changes, since the 72-hour planning window discussed in NEI 99-02 was not met for each individual reduction?

Response See response for FAQ 158.

ID 156

Posting Date 04/01/2000

Question For a situation where an unplanned runback (greater than 20%) is properly terminated by a trip (since the runback was unable to reduce power rapidly enough), should the event be counted as both an Unplanned Power Change and an Unplanned Scram?

Response No.

ID 6

Posting Date 11/11/1999

Question Relative to power reductions greater than 20%, the difference between planned versus unplanned maintenance seems to be the 72 hour timeframe. In that context, we may have a situation whereby a main steam relief valve tailpipe temperature sensor is indicating a leak. The temperature is monitored and plans are made for repairs. Because the valve is located inside primary containment (inerted with nitrogen for fire protection reasons) a range of contingencies is prepared, including the replacement of the relief valve. The monitoring continues (days/weeks beyond 72 hours from problem identification) until an administratively established limit for tailpipe temperature is achieved -- at which time a plant shutdown is initiated (power reduction greater than 20%). Would this reduction be counted as an unplanned power reduction greater than 20%?

A similar situation could exist for reactor coolant leakage monitoring. We have two types of leakage -- equipment leakage (identified) and floor leakage (unidentified) inside primary containment. The leakage is monitored twice per shift. At some point, indications suggest that a recirculation pump (inside containment) seal is degrading. The indications are flow to the seal and an increase in floor leakage (unidentified). Past experience and the indications conclude the floor leakage is due to recirculation pump seal degradation. Plans are made to replace or repair the seal if administratively established limits are met or exceeded (not Tech Spec). This would require a plant shutdown. The indications are monitored. The indications continue (days/weeks beyond 72 hours from problem identification) until the administrative limit is achieved. A plant shutdown (power reduction greater than 20%). Would this be counted as an unplanned power reduction greater than 20%?

Response The cases described would not be counted in the unplanned power changes indicator. In both of the cases described, the time period between discovery of an off-normal condition (i.e., main steam relief valve leakage and possible recirculation pump seal degradation) exceeded 72 hours. This allowed for assessment of plant conditions, preparation and review in anticipation of an orderly power reduction and shutdown.

ID 3

Posting Date 11/11/1999

Question Does the 20% power change rule apply to an uncontrolled excursion or are any uncontrolled excursions counted? Our specific example is:

Unit 1 experienced an uncontrolled power excursion from 100% to 100.3% due to a high level feed water heater dump valve failure.

Response The performance indicator counts any unplanned changes in reactor power greater than 20% of full power. In your example, the excursion does not exceed 20% and would thus not be counted under this performance indicator.

ID 2

Posting Date 11/11/1999

Question If a licensee plans to reduce from 100% to 85% (15% reduction) but due to equipment malfunction (boron dilution) overshoots and reduces to 70%. Since 15% was already planned, is the overall transient considered (100-70 = 30% and counted as a "hit"), or is it only for transients beyond that planned (85-70 = 15% and not counted as a "hit")?

Response The Unplanned Power Changes Performance Indicator addresses changes in reactor power that are not an expected part of a planned evolution or test. In the proposed example, the unplanned portion of the power evolution resulted in a 15% change in power and would not count toward the performance indicator.

ID 1

Posting Date 11/11/1999

Question If a reduction from 100% to 70% is planned, and an additional 25% must occur if the situation is worse than expected, can a licensee preplan (at the time of preplanning the 30% reduction) a "second contingency step planning" for the additional 25%.

Response The 72 hour planning period is used as a mark to indicate that necessary planning has occurred to address the proposed power change. This planning may include contingency power changes that would not be counted toward the performance indicator.

Mitigating Systems

MS01 Emergency AC Power System Unavailability

ID 405

Posting Date 11/17/2005

Question **(Appendix D, Browns Ferry 2 and 3**

Browns Ferry Unit 1 is being recovered from an extended shutdown. Recovery efforts include replacement of cables to the Division I and Division II Emergency AC (EAC) power. The cables are being replaced in order to provide qualified cables (including requisite documentation) to meet current Environmental Qualification, Post Accident Monitoring, Voltage Drop/Ampacity/Short Circuit requirements, Appendix R, Electrical Separation and to address breakage as identified by electrical calculations.

The Division I and Division II EAC for Units 1 and 2 each contain 2 Emergency Diesel Generators and 2 4160v Shutdown Boards with each Emergency Diesel Generator and Shutdown Board supplying approximately 50% of the emergency power required for each Division EAC. The Emergency Diesel Generators and Shutdown Board are paired as A & B in Division I and C & D in Division II.

To replace these cables, Emergency Diesel Generators A, B, and D and 4160v Shutdown Boards A, B and D will be removed from service one train at a time. The work is planned such that when A Emergency Diesel Generator and 4160v Shutdown Board A are out of service, the B, C, and D Emergency Diesel Generators and B, C, and D 4160v Shutdown Boards will remain available. Also when the B or D train is out of service the other three trains will remain available.

The work to replace the cables on any one of the trains can be done within the Tech Spec AOT of 14 days for the Emergency Diesel Generator.

A quantitative risk assessment has been performed on the configuration as required by NEI 99-02 in order to qualify for the exemption of unavailable hours. This risk assessment was done in 1997 in conjunction with the license amendment which extended the AOT from 7 to 14 days.

Browns Ferry personnel have taken great efforts to minimize any impacts of Unit 1 recovery on the operating units (Units 2 and 3). This is the second instance in which Browns Ferry has requested an exemption of unavailable hours (see discussion on FAQ 381 below) accrued as a result of Unit 1 recovery activities. As a result of this FAQ, Browns Ferry personnel have reviewed upcoming activities and, at this time, do not anticipate any other planned activities for which another exemption would be required. However, the recovery of Unit 1 is a large and complex project. It is possible that future activities might occur with unanticipated effects that would necessitate another request for exemption.

It should be noted that this exemption request (and FAQ 381) is not an overhaul exemption as discussed in the Clarifying Notes subsection of Section 2.2 of NEI 99-02, but a Plant Specific exception as described in Appendix D. The justification of this FAQ (and the previous FAQ) is that the

unavailable hours resulting from restart of an idled unit is a plant-specific situation that was not anticipated during the formulation of the guidance document and that the hours, if counted, would not provide an accurate picture of the performance of the systems as intended by the performance indicator.

NEI 99-02 limits planned overhaul maintenance exemptions to once per train per operating cycle. There is no similar limit to exemptions for Appendix D issues. It is TVAs intent to minimize these requests and as stated before, our current review has not identified any foreseeable circumstances requiring another request of this type, although it cannot be completely ruled out due to the scope and complexity of the project.

Response The effect of the Browns Ferry Nuclear (BFN) Unit 1 Emergency AC (EAC) power restoration activities on Unit 2 and Unit 3 system unavailabilities is a unique condition that had not been anticipated during the development of the PI guidance document. The unavailability of the Unit 2 and Unit 3 systems due to the Unit 1 EAC restoration work does not truly reflect the performance of the Unit 2 and Unit 3 systems. For this unique, one time only activity, the planned BFN Unit 1 EAC restoration may be treated similar to Planned Overhaul Maintenance. That is, if additional time is needed beyond the original schedule duration to repair equipment problems discovered during the restoration activities, the additional hours would count toward the indicator. In addition, other activities may be performed with the restoration activity as long as the outage duration is bounded by the restoration activities. If the restoration activities are complete, and the outage continues due to non restoration activities, the additional hours would count toward the indicator.

ID 398

Posting Date 07/21/2005

Question **(APPENDIX D)**

The Oconee Nuclear Station emergency power is provided by the Keowee Hydro units (KHUs) located within the Oconee Owner Controlled Area. The Keowee hydroelectric station has been in service since 1971, with the last major overhaul performed in 1985. Duke Energy (Duke) is performing significant upgrades and overhaul maintenance to each KHU to ensure future reliability. This work includes replacement of the governor, exciters, and batteries, and weld repair on the turbine blades and discharge ring along with draft tube concrete repair. This FAQ seeks an exemption from counting the planned overhaul maintenance hours for the one-time KHU outages.

Was there NRC approval through an NOED, Technical Specification change, or other means?

An amendment was approved by the NRC to temporarily extend Technical Specification (TS) 3.8.1 Required Action Completion Times to allow significant maintenance and upgrades to be performed. Even though each KHU is being upgraded one at a time, the tasks of isolating and un-isolating the unit being upgraded makes both KHUs inoperable. The approval allows Duke to temporarily extend the 60 hour Completion Time for restoring one Keowee Hydro Unit (KHU) when
both are inoperable by 120 cumulative hours over two dual KHU outages. For example, 60 hour + 40 and 60 hours + 80 for a total of 240 hours is allowed during each KHU (KHU1 & KHU2) Refurbishment Outage. KHU 1 has already completed its extended outage using 206 of the 240 allowed hours in the dual KHU outage. The KHU 2 will be performed in January - February 2005 and is expected to use a similar number of hours spread over two dual KHU outages. Even though one KHU is being upgraded at a time, the tasks of isolating and un-isolating the unit being upgraded makes both KHUs inoperable. During the time period when both KHUs are inoperable, both TS 3.8.1 Required Actions C.2.2.5 and H.2 will be entered. Entry into H.2 is relevant to the underground. Only the underground unavailable hours are reported for PI.

Was there a quantitative risk-assessment of the overhaul activity?

A quantitative risk analysis was performed. The analysis showed that the planned configuration was acceptable per Regulatory Guide 1.177 and 1.174. The cumulative core damage probability (CCDP) for each extended KHU outage was calculated to be 4.4E-07. A subset of the extended single unit outage is the two dual KHU outages (which makes the underground path unavailable for the period of time mentioned above.)

What is the expected improvement in plant performance as a result of the overhaul and what is the net change in risk as a result of the overhaul activity?

The net change in risk as a result of the overhaul activity is reduced because of the expected decrease in future Emergency Power unavailability as a result of the overhaul, and the contingency measures to be utilized during the overhaul. During Duke's December 16, 2003, meeting with NRC, the Staff indicated that even though the revised cumulative CDP was in the E-07 range, their guidelines required defense-in-depth measures to be considered in order to approve the LAR. Duke presented defense-in-depth measures credited to offset the additional risks associated with the dual KHU outages during that meeting and in a December 18, 2003 letter. These defense-in-depth measures, which address grid-related events, switchyard-centered events, and weather-related events, are as follows:

For grid-related events

- A 100 kV dedicated line separated from the grid
- A Lee Combustion Turbine (LCT) already running and energizing the standby buses via the 100 kV dedicated line
- Two additional LCTs available, either of which can provide the necessary power
- One of the two additional LCTs running and available to be connected to the 100 kV dedicated line during the dual KHU outage
- A Jocassee Hydro Unit capable of providing power via a dedicated line separated from the grid
- Up to three additional Jocassee hydro units, any of which can provide necessary power and be connected to the dedicated line
- Standby Shutdown Facility (SSF) remains available as an alternate shutdown method the SSF will be removed from service for its scheduled monthly maintenance, but not during the dual unit outage

For switchyard centered events

- 100 kV line not connected to switchyard
- Power from Jocassee can be recovered quickly
- SSF remains available as an alternate shutdown method

For weather-related events that take out switchyard or power lines coming into switchyard - from a qualitative standpoint:

- Power lines come in from different directions so it is not likely that Oconee would lose power from all the lines at the same time
- The likelihood of having a weather event that takes out all power lines is low
- SSF remains available as an alternate shutdown method

For this one-time plant specific situation, can the planned overhaul hours for the emergency power support system be excluded from the computation of monitored system unavailability?

Response Yes. The licensee satisfied the conditions described in NEI 99-02, Revision 3, pages 26 and 27, and the planned overhaul hours may be excluded from the SSU calculation.

ID 374

Posting Date 11/18/2004

Question Appendix D FAQ: Mitigating Systems Safety System Unavailability, Emergency AC Power

During a monthly surveillance test of Emergency Diesel Generator 3 (EDG3), an alarm was received in the control room for an abnormal condition. The jacket water cooling supply to EDG3 had experienced a small leak (i.e., less than 1 gpm) at a coupling connection that resulted in a low level condition and subsequent control room alarm. The Low Jacket Water Pressure Alarm, which annunciates locally and in the control room, indicated low pump suction pressure. This was due to low level in the diesel generator jacket water expansion tank. An Auxiliary Operator (AO) stationed at EDG3 responded to the alarm by opening the manual supply valve to provide makeup water to the expansion tank. EDG3 continued to function normally and the surveillance test was completed satisfactorily. Review of data determined that improper tightening of the coupling was performed after the monthly EDG run on December 8, which led to an unacceptable leak if the EDG was required to run. The coupling was properly repaired and tested, and declared to be available and operable on January 6. The condition existed for approximately 28 days.

Although the recovery action was conducted outside of the main control room, it was a simple evolution directed by a procedure step, with a high probability of success. This operator response is similar to the response described in Appendix D FAQ 301. In addition, this operator action would be successful during a postulated loss of offsite power event, except for a 23 hour period when the demineralized water supply level was too low to support gravity feed. The engineering analysis determined that a level of 21 5 of demineralized water supply level was necessary to support gravity feed to the expansion tank. Another 9 (4,740 gallons) was added to this level to allow for the leak and nominal usage and makeup over the 24 hour mission time. Using this analysis, any time the demineralized water level fell below 22 2, the EDG was considered to be unavailable. A human reliability analysis calculated the probability of an AO failing to add water to the expansion tank from receipt of the low pressure alarm to be 4.7 E-3. In other words, there would be a greater than 99.5% probability of successful task completion within twenty minutes of receiving the annunciator. Vendor analysis determined that, with the existing leak rate, the EDG would remain undamaged for twenty minutes.

The human reliability analysis considered that the low jacket water pressure would be annunciated in the control room, the annunciator procedure provided specific direction for filling the expansion tank, the action is reinforced through operator training, and sufficient time would be available to perform the simple action. In its calculation of the probability of operator recovery, the analysis also considered that another indicator, a low-level expansion tank alarm was out-of-service during this time period. However, although the low expansion tank alarm was out of service, it results in low pump suction pressure which did annunciate.
NEI 99-02 Appendix D lists several issues that may be addressed for exceptions to allow credit for operator compensatory actions to mitigate the effects of unavailability of monitored systems.

1. The capability to recognize the need for compensatory actions Low pump suction pressure annunciates in the control room.
2. The availability of trained personnel to perform the compensatory action This is an uncomplicated action, but operators are trained on it. An auxiliary operator simply has to open one manual valve as directed by the annunciator procedure.
3. The means of communications between the control room and the local operator Communications can be accomplished either via the plant PA system or a portable radio.
4. The availability of compensatory equipment No compensatory equipment is necessary.
5. The availability of a procedure for compensatory actions There is an annunciator procedure in the diesel generator room that would direct the auxiliary operator to open the manual valve.
6. The frequency with which the compensatory actions are performed This action is performed infrequently, but it was demonstrated to be successful during the surveillance test.
7. The probability of successful completion of compensatory actions within the required time The human reliability analysis determined that there was a 99.5% probability of successful completion of compensatory action within the required time.

In summary, over a 28-day period, jacket water cooling for EDG3 was degraded, but functional for approximately 27 days, and was totally unavailable for 23 hours. This is based on a review of Operator logs, plant trending computer points, and flow calculations. During the 27-day degraded period, a simple manual action directed by procedure and performed by an operator would have been used to ensure that jacket water was available.

Should fault exposure hours be reported for the 27 days when the Emergency Diesel Generator 3 jacket water was considered to be degraded but functional?

Response Yes. In general, credit for operator actions to restore monitored systems is limited to those situations described in NEI 99 02, page 27, lines 14 through 23, and page 31, lines 8 through 16. (Note that for equipment malfunctions, restoration actions must be performed in the control room.) Exceptions to these requirements may be approved on a plant specific basis as described in Appendix D, page D 2, lines 19 through 31. The most important issue that differentiates a monitored system from a support system is that NRC approval through an NOED, a technical specification change, or some other means is mandatory for a monitored system (because a monitored system must meet a higher standard than a support system).

ID 367

Posting Date 07/22/2004

Question This FAQ seeks clarification of the guidance in NEI 99-02 regarding fault exposure. Specifically, NEI 99-02, page 30, lines 3-6 describe fault exposure (T) in terms of failure and the failures known time of occurrence and known time of discovery. Lines 13-20 provide T/2 fault exposure guidance where the time of failure is uncertain and only the time of discovery is known. This clarification will be used to determine whether a situation is T or T/2.

Emergency diesel generator A (EDG A) failed a monthly surveillance on September 29, 2003. A fuel oil line connection on the diesel failed during the surveillance; the surveillance was halted and the diesel declared

inoperable. Based upon guidance in NEI 99-02 and FAQ 318, the plant reported in the 3Q03 performance indicator submittal T/2 fault exposure hours based upon the time from the last successful surveillance (September 2, 2003) until EDG A failed on September 29, 2003. This is due largely to the guidance that notes *Fault expo Fault exposure hours for this case must be estimated. The value used to estimate the fault exposure hours for this case is: one half the time since the last successful test or operation that proved the system was capable of performing its safety function*." Is this interpretation of the guidance correct?

Additional Details:

A root cause determined that plant maintenance introduced a latent condition on May 16, 2003 during maintenance on the diesel that lead to EDG A failure during the September 29 surveillance. The root cause established the failure mechanism was fatigue. A time of failure after the introduction of the latent maintenance condition cannot be predicted with certainty because of the complexity of the fatigue phenomenon e.g., fatigue failure is a non-linear function of time; it is also cumulative. The fatigue failure was further complicated by multiple starts and stops of the diesel during monthly surveillances. (From the time the tubing was installed in May 2003, EDG A ran for almost 29 hours over a period of about 4 months and 5 successful surveillances.)

Response For this specific situation, use of T/2 is acceptable. Engineering judgment in conjunction with analytical techniques was unable to determine the time when the train would have been unavailable with enough certainty for use in the performance indicator.

ID 363

Posting Date 04/22/2004

Question Appendix D

NEI 99-02 Rev 2 recognizes that some provisions are intentionally restrictive to ensure that the NRC is informed of plant conditions. On page D-2 lines 19 through 31 guidance is given to allow exceptions to allow credit for operator compensatory actions to mitigate the effects of unavailability of monitored systems.

During a surveillance test on December 9, 2003, South Texas Project Unit 2 SDG-22 experienced a catastrophic failure and STP Nuclear Operating Company (STPNOC) could not complete the repairs in the current 14 day AOT. As a result SPTNOC submitted a series of Technical Specification amendment request to allow a one-time-only increase of the Allowed Outage Time to a total of 113 days. These amendments were approved by the NRC and resulted in the continued operation of STP from December 9, 2003 until March 31, 2004. This one-time-only extended allowed outage time will result in 2,712 hours of unavailability on SDG 22 and a Performance Indicator value of 4.5% (White) for Emergency AC Power. If the Technical Specification one-time change had not been granted, STP would have incurred less than 336 hours of unavailability on SDG 22 and would have remained in the Green band (1.6%). For Emergency AC Power, the NEI 99-02R2 NRC Performance Indicator Green/White threshold is set at 2.5%, while the White/Yellow threshold is set at 10%.

STP Unit 2 received an allowable outage time (AOT) extension in an approved license amendment request, predicated upon a combination of alternative systems and operator compensatory actions for the unavailable system. The NRC evaluated, and documented the acceptability of these alternative methods; the NRCs SER confirms that the licensee did indeed provide an acceptable interim compliance configuration in accordance with their new license amendment. See Event Details and Supporting Information below for more information.

License amendments do redefine a plants licensing basis. If alternative methods are proposed, submitted, reviewed, approved, and inspected, then the NRC has publicly endorsed the alternative methods as providing acceptable compliance. As long as the licensee maintains the newly licensed configuration and compensatory measures, the unavailable hours should not accrue unless the newly licensed configuration was no longer maintained. NEI 99-02 Rev 2 allows for an exemption of unavailability hours based on operator compensatory actions

Since the unavailability incurred by SDG 22 was approved by a license amendment to the STP Unit 2 Technical Specifications that provided compensatory measures and an approved credited backup power supply to Train "B", and since counting all hours incurred would significantly mask future degrading performance, should the unavailable hours be counted only from the time of discovery until the compensatory measures were in place?

Response Yes, the unavailable hours should be counted only from the time the diesel became inoperable until the time that the compensatory measures and non-class diesel generators were in place and remained in place. This is based upon the following factors:

- The condition was approved by a change to the plant Technical Specifications.
- The Technical Specification change credited a backup non-class power supply for SDG 22 in addition to the other two Standby Diesel Generators at the Unit.
- There are control room alarms to alert the Control Room operator of the need for the compensatory measures.
- Dedicated operators are stationed in the area to complete the recovery action.
- The operators have procedures and training has been accomplished for the recovery action.
- There are at least four means of communication between the Control Room and the local operators.
- All necessary equipment for recovery action is pre-staged and has been tested.
- Indication of successful recovery actions is available locally and in the Control Room.
- The non-class diesel generators are inspected weekly and operated monthly on a load bank to verify their availability.
- The probability of successful completion of compensatory actions were evaluated by sensitivity studies as part of the amendment request and accepted by the NRC SER.

ID 335

Posting Date 03/20/2003

Question The overhaul of the EDG fuel priming pump was planned corrective maintenance and was scheduled as part of the overall overhaul activities for the EDG. Post maintenance testing revealed that parts installed in the fuel oil priming pump during the overhaul did not result in optimal performance. Although the pump operation would not have prevented the fuel oil priming pump from fulfilling its required safety function, the decision was made to rework the pump to recover pump performance. The rework resulted in extending the overhaul past its originally scheduled time. Does the maintenance rework count as planned overhaul maintenance?

Response The corrective maintenance activity extended the overhaul beyond the planned overhaul hours. Those additional hours count toward the indicator. NEI 99-02 will be changed at the next revision to make this clear.

ID 325

Posting Date 12/12/2002

Question Treatment of Planned Overhaul Maintenance in the Clarifying Notes section of the Mitigating Systems Cornerstone, Safety System Unavailability, states that plants that perform on-line planned overhaul maintenance (i.e., within approved Technical Specification allowed Outage Time) do not have to include planned overhaul hours in the unavailable hours for this performance indicator under the conditions noted. This section further states that the planned overhaul maintenance may be applied once per train per operating cycle. EDG(s) at our plant are on an 18 month overhaul frequency per T.S.4.6.A.3.a, while the plant operating cycles are typically a month or two longer. Thus, the EDG 18 month overhaul will occur twice in some cycles. If major overhauls, performed in accordance with the plants technical specification frequency, result in more than one major overhaul being performed within the same operating cycle, can both of these overhauls be excluded from counting as planned unavailable hours?

Response It depends on the quantitative risk assessment that was performed to justify the exclusion. If the assessment specifically addressed the use of the Technical Specification AOT twice per operating cycle, then both overhauls may be excluded from the PI. If, however, the licensees assessment assumed that only one AOT would be used per operating cycle, or if the licensee submitted a request to the NRC for an extended AOT and did not specify the number of times the AOT would be used per cycle, then the exemption may be used only once. However, the licensee has the option to perform a risk analysis that assumes the use of two AOTs per cycle. If that analysis meets the requirements of NEI 99-02 Rev. 2, page 28 line 15, through page 29 line 2, then the licensee may exclude the overhaul hours for the two overhauls.

ID 324

Posting Date 10/31/2002

Question The station programmatically maintains and manages risk associated with overhaul maintenance performed within Technical Specification Allowed Outage Times (AOTs). The program implements Regulatory Guide 1.177 and/or NUMARC 93-01 requirements for risk management during the maintenance activities. All work to be accomplished during a planned overhaul is scheduled in advance and includes maintenance activities that are required to improve equipment reliability and availability. The station considers overhaul maintenance as those overhaul activities associated with the major component as well as pre-planned corrective and preventive maintenance on critical subcomponents. For example, the EDG preventive maintenance program requires hydrostatic testing of the lube oil cooler every 12 years and the subsequent repair or replacement of the cooler as necessary. The purpose of the hydrostatic test is to preemptively reveal defects to preclude a run-time failure by applying far more pressure to the lube oil cooler than would be experienced during normal operation. This test was a scheduled item during a planned EDG overhaul, and the lube oil cooler did not pass the hydrostatic test. The lube oil cooler replacement was not included as a scheduled contingency item, nor was a replacement cooler on-site. However, replacement coolers of this type were known to be readily obtainable. The original overhaul duration was extended by the time needed for procurement and installation of a replacement lube oil cooler. Do the additional hours count as planned overhaul maintenance hours?

Response No. The hours must be included in the indicator. When problems are discovered that are due to a licensee performance deficiency, and resolution of that problem results in additional hours beyond those scheduled for the overhaul, the additional hours must be counted. In this case, the licensees RT examination of the lube oil cooler to determine its susceptibility to failure during the planned hydrostatic test was faulty. That examination led them to erroneously conclude that their cooler was of a more robust design than it actually was and that it was not susceptible to failure. This deficiency resulted in an unplanned extension to the planned overhaul.

ID 322

Posting Date 10/31/2002

Question **Appendix D Surry**

NEI 99-02, Revision 1, in the Clarifying Notes for the Mitigating Systems Cornerstone, allows a licensee to not count planned unavailable hours under certain conditions when testing a monitored system.

At our two-unit PWR station, three EDGs provide emergency AC power. There is one dedicated diesel for each unit and one swing diesel available for either unit. During the monthly surveillance testing required by Technical Specifications, there is an approximate four-hour period when the EDG is run for the operational portion of the test and is inoperable but available. In 2001, surveillance-testing procedures were revised to take credit for restoration actions that would enable not counting the hours as unavailable.

The restoration actions for the two dedicated diesels during the approximate four-hour period consist of implementing a contingency actions attachment to the test procedure. This process verifies system alignment and places the EDG on its emergency bus. The steps allow the dedicated control room operator to change the emergency generator auto-exercise selector from exercise to auto, verify or place the emergency supply switch in auto, depress the emergency generator fast start reset button and adjust the engine speed and voltage as necessary. The process steps are, individually and collectively, simple and done by a dedicated operator. The last step requires the governor speed droop control to be adjusted to zero. However, the speed droop adjustment is not required for the EDG to satisfy its safety function. This step is performed to relieve the dedicated operator and does not challenge operation or control of the EDG.

Question (1); can credit be taken during the restoration actions that require only one dedicated control room operator (no other assigned duties) resulting in not counting the unavailable hours during this portion of the testing of the dedicated EDGs? The restoration actions for the swing diesel also consist of implementing a contingency actions attachment to the test procedure with a few minor differences. Three additional steps determine which emergency bus the swing EDG needs to be aligned to before placing the swing EDG on that emergency bus. The rest of the actions are identical to the dedicated EDG explanation described above.

Question (2); can credit be taken for these restoration actions that require only one dedicated control room operator (no other assigned duties) resulting in not counting the unavailable hours during this portion of the testing of the swing EDG?

Response Question 1: No. A review of the restoration actions specified in the licensees surveillance procedure was performed to determine if the restoration actions were uncomplicated (a single or a few simple actions) and not requiring diagnosis or repair as discussed in NEI 99-02, revision 2. Although some of the individual restoration actions met the above criteria, the procedure involved eight or more actions, two of which did not meet the above criteria. Specifically, the two actions involve the diagnosis and reaction to particular plant parameters. For an approximate three minute period, while loads are sequenced onto the emergency bus, engine speed must be adjusted to maintain bus frequency and bus voltage must be adjusted to maintain voltage within specified limits. Therefore, unavailable hours should be counted during the testing of the dedicated EDGs.

Question 2: No. The answer to question 1 also applies to the swing EDG. The restoration actions for the swing EDG are further complicated by the potential need to remove the EDG from one units emergency bus and subsequently place the swing EDG onto the other units emergency bus. These additional restoration actions,

coupled with the restoration actions required for the dedicated EDGs, exceed those actions constituting a single or a few simple actions. Therefore unavailable hours should be counted during the testing of the swing EDG.

ID 318

Posting Date 09/26/2002

Question In August 2001, Our plant had just completed the monthly EDG load-run surveillance and had passed the plants load and duration test specification. The EDG was being secured from the test in accordance with the surveillance. Generator real load (kW) was initially reduced, when it was discovered that generator reactive load (KVAR) would not respond to remote or local control inputs. Operations then tripped the generator output breaker and secured the EDG and declared it out of service. Initial trouble shooting of the voltage regulator was performed and the engine was run the next day with similar response to load control. At this point the engine was removed from service for repair of the generator. The root cause evaluation determined that the generator had two shorted coils. The cause of the shorted coils was degradation of winding laminations over time due to poor winding processes at a repair vendors facility for work performed in 1993. This degradation ultimately resulted in contact between a generator winding and uninsulated wedge block bolting internal to the generator while the engine was being secured following successfully satisfying the monthly surveillance.

In applying fault exposure hours to this scenario we believe that by meeting the plants load and duration test specification, during the surveillance, NEI 99-02, Revision 1, page 38 line 30 criterion for successful start and load-run was met. Because the failure occurred during the unload and shutdown portion of the surveillance (the failures time of occurrence is known), fault exposure is not applicable. The time that the engine was out of service for the initial voltage regulator trouble shooting, the second attempt to run the engine and hours associated with the generator repair are counted as unplanned unavailable hours.

Have we correctly interpreted NEI 99-02 guidance that fault exposure hours would not be reported in this situation?

Response No. While the diesel had officially passed the surveillance test, the plant was still getting information from the surveillance test during the diesel shutdown. T/2 fault exposure should be taken from the last successful test of the diesel, i.e., the last monthly test before this occurrence.

ID 317

Posting Date 08/22/2002

Question Florida Power Corporation's (FPC) Crystal River Unit 3 (CR-3) seeks to apply the NEI 99-02, Revision 2, Safety System Unavailability (SSU) T/2 Fault Exposure Hour treatment for T/2 Fault Exposure Hours incurred prior to January 1, 2002.

Specifically, FPC seeks approval to remove 345 T/2 Fault Exposure Hours incurred in a single increment against Emergency Diesel Generator EGDG-1B from the calculation of Emergency AC SSU PI. These hours DID NOT result in the associated SSU Performance Indicator (PI) exceeding the green-white threshold. In accordance with the guidance of NEI 99-02, Revision 2, these hours would be reported in the Comment section of the PI data file.

Continuing to carry these Emergency AC SSU T/2 Fault Exposure Hours until the Fault Exposure Hour reset criteria are met is inconsistent with the current philosophy for treatment of T/2 Fault Exposure Hours. This situation will result in the SSU PIs for various plants being non-comparable depending on when any T/2 Fault Exposure Hours were discovered. This could easily occur at a multi-unit site. Further, if a plant discovered different events which contributed T/2 Fault Exposure Hours attributable to a period before January 1, 2002, and another after, the PI would be internally inconsistent.

Response This situation does not meet the requirements for resetting fault exposure hours, in that the green white threshold was not exceeded.

ID 314

Posting Date 08/22/2002

Question **Appendix D Oconee**

The Oconee Nuclear Station has a unique source of emergency AC power. In lieu of Emergency Diesel Generators, Oconee emergency power is provided by one of two identical Keowee Hydro units located within the Oconee Owner Controlled Area. These extremely reliable units are each capable of supplying ample power for the plant loads for all three Oconee units. Additionally, they are also used for commercial generation using an overhead line to the Oconee switchyard.

Train separation at Oconee is initially established at the three (3) 4160 volt load buses in each unit. These buses are all fed from one of two main feeder buses in each unit, that are both in turn supplied from a single

underground power cable from a Keowee unit. This underground path is preferred and is preferentially selected on a loss of offsite power and an Engineered Safeguards signal. If the Keowee unit aligned to the underground path trips, the ONS loads will be automatically transferred to the remaining adjacent Keowee unit. As an additional source of power, the main feeder buses can also be fed from the Keowee overhead power line via the Oconee switchyard.

The PRA calculations indicate the Underground Path is significantly more important than the Overhead Path, which is susceptible to external events and therefore can be discounted. From the PRA results, it is recommended that safety system unavailability reporting for the MS01 performance indicator be based on the Underground path. PRA calculations support the following thresholds based upon the delta CDF for unavailability of the Underground Path.

The Green/White threshold value is consistent with the Maintenance Rule limit for unavailability of the Underground Path. Also, historical unavailability of the Underground Path would place ONS mid-way in the green band, which is consistent with average industry performance for the MS01 indicator. The White/Yellow threshold of 4.0% provides an appropriate white band as compared to the threshold of 5.0% indicated in NEI 99-02 for a system with two trains of Emergency AC equipment. The Yellow/Red threshold of 10% is conservative and is consistent with NEI 99-02 for a system with two trains of Emergency AC equipment. Monitoring the underground path only, are 2.0%, 4.0% and 10.0%, acceptable threshold values for the ONS Emergency Power performance indicator?

Response Yes.

ID 285

Posting Date 09/12/2001

Question NEI 99-02 Revision 1, Page 1, INTRODUCTION, line 22 states: "Performance indicators are used to assess licensee performance in each cornerstone." Consider the situation where a certified vendor supplied a safety related sub-component for a standby diesel generator. This sub-component was refurbished, tested and certified by the Vendor with missing parts. The missing parts eventually manifested themselves as a sub-component failure that lead to a main component operability test failure. The Vendor issued a Part 21 Notification for the condition after notified by the Licensee of the test failure. (The licensee conducted a successful post maintenance surveillance and two subsequent successful monthly surveillances before the test failure. Thus there was fault exposure and unplanned maintenance unavailability incurred.)
If a licensee is required to take a component out of service for evaluation and corrective actions related to a Part 21 Notification or if a Part 21 Notification is issued in response to a licensee identified condition (i.e. Report # 10CFR21-0081), should the licensee have to count the fault exposure and unplanned unavailability hours incurred?

Response Yes. The PI measures unavailability of the equipment, not responsibility for unavailability.

ID 283

Posting Date 08/16/2001

Question (This FAQ is a replacement for FAQ 276. FAQ 276 has been withdrawn)

Appendix D: Susquehanna

Analysis has shown that when RHR is operated in the Suppression Pool Cooling (SPC) Mode, the potential for a waterhammer in the RHR piping exists for design basis accident conditions of LOCA with simultaneous LOOP. SPC is used during normal plant operation to control suppression pool temperature within Tech Spec requirements, and for quarterly Tech Spec surveillance testing. We do not enter an LCO when SPC mode is used for routine suppression pool temperature control or surveillance testing because, as stated in the FSAR, the systems response to design basis LOCA/LOOP events while in SPC configuration determined that a usage factor of 10% is acceptable. The probability of the event of concern is 6.4 E-10.If the specified design basis accident scenario occurs while the RHR system is in SPC mode, there is a potential for collateral equipment damage that could subsequently affect the ability of the system to perform the safety function. If the time RHR is run in SPC mode must be counted as unavailability, then our station RHR system indicator will be forever white due to the number of hours of normal SPC run time (approximately 300 hours per year). This would tend to mask any other problems, which would not be visible until the indicator turned yellow at 5.0%. Should our station count unavailability for the time when RHR is operated in SPC mode for temperature control or surveillance testing?

Response No, as long as the plant is being operated in accordance with technical specifications and the updated FSAR.

ID 272

Posting Date 05/31/2001

Question NEI 99-02, Revision 0, page 48, line 1 (Clarifying Notes) states:
"When determining fault exposure hours for the failure of an EDG to load-run following a successful start, the last successful operation or test is the previous successful load-run (not just a successful start). To be considered a successful load-run operation or test, an EDG load-run attempt must have followed a successful start and satisfied one of the following criteria:

a load run of any duration that resulted from a real (e.g., not a test) manual or automatic start signal

a load-run test that successfully satisfied the plant's load and duration test specifications

other operation (e.g., special tests) in which the emergency diesel generator was run for at least one hour with at least 50% of design load

When an EDG fails to satisfy the 12/18/24- month 24-hour duration surveillance test, the faulted hours are computed based on the last known satisfactory load test of the diesel generator as defined in the three bullets above."

The following sentence states:

"For example, if the EDG is shutdown during a surveillance test because of a failure that would prevent the EDG from satisfying the surveillance criteria, the fault exposure unavailable hours would be computed based upon the time of the last surveillance test that would have exposed the discovered fault."

If a 24-hour duration surveillance test revealed a failure due to a cause that pre-existed during the entire 12/18/24 month operating cycle, then it is not clear whether fault exposure should be calculated based on the guidance in the three listed criteria, or the three listed criteria are totally disregarded if the failure was not revealed until the 24-hour duration surveillance test. This is particularly unclear for a condition that could have been revealed during any test (e.g., any monthly 1-hour load-run surveillance), but actually happened during the 24-hour duration surveillance test.

Response The key to interpreting this section of the guideline is determining the cause of the surveillance failure. If the cause is known (and the time of failure cannot be ascertained) the fault exposure time would be calculated as half the time since the last test which could have revealed the failure. This could be any of the load run tests described in the section, provided it was capable of identifying the failure.

ID 258

Posting Date 03/02/2001

Question Turkey Point's Unit 3 Emergency Diesel Generators EDGs) are air-cooled, using very large radiators (eight assemblies, each weighing 300-400 pounds) which form one end of the EDG building. After 12 years of operation the radiators began to exhibit signs of leakage, and the plant decided to replace them. Replacing all eight radiator assemblies is a labor-intensiveactivity, that requires that sections of the missile shield grating be removed, heat deflecting cowling be cut away, and support structures be built above and around the existing radiators to facilitate the fitup process. This activity could not have been completed within the standard 72 hour allowed outage time (AOT). Last year Turkey Point requested, and received, a license amendment for an extended AOT, specifically for the replacement of these radiators. NEI 99-02 allows for the exclusion of planned overhaul maintenance hours from the EAC performance indicator, but does not define overhaul maintenance. Does an activity as extensive as replacing the majority of the cooling system, for which an extended AOT was granted, qualify as overhaul maintenance?

Response In this specific case, yes, for three reasons: (1) that activity involves disassembly and reassembly of major portions of the EDG system en toto, tantamount to an overhaul; (2) the activity is infrequent, i.e., the same as the vendor's recommendation for overhaul of the engine alone (every 12 years); and (3) the NRC specifically granted an AOT extension for thisactivity supported by a quantitative analysis

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ID 257

Posting Date 03/02/2001

Question The Emergency AC Power System monitored function for the indicator is, "The ability of the emergency generators to provide AC power to the class 1E buses upon a loss of off-site power." However, on page 26 of NEI 99-02, Rev 0 under testing where simple operator action is allowed for restoration, it states "The intent of this paragraph 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."
For purposes of this indicator are we to assume a simultaneous loss of off-site power and also accident conditions? This may make a difference on the diesel generator response, operator restoration actions and ultimately whether or not we count unavailability during our surveillance test runs.

Response Yes, you should assume a simultaneous loss of off-site power and also accident conditions if they are specified in your design and licensing bases.

ID 218

Posting Date 10/01/2000

Question The station UFSAR states that operator actions are required to restore the EDG room ventilation system following: 1) a fire protection system actuation 2) a HELB occurring outside of the EDG rooms. The restoration actions (manually open several sets of dampers) are directed by an operating procedure. During certain fire protection system surveillances, the EDG room ventilation system dampers are closed to the same configuration as when a HELB or fire protection system actuation occurs. No other actions are taken that would otherwise affect EDG start and load capability. The steps necessary to return the ventilation subsystem to available are specified in an operating procedure and the guidance is accessible for the personnel performing the steps. Operations personnel are briefed on the status of the DG and its room ventilation subsystem as part of the prejob briefing for the performance of the surveillance. The individual specifically involved with restoring the ventilation is briefed on the time restraints and dedicated to the testing. Since the UFSAR credits the operator actions required to restore the system to its normal operating configuration following a fire protection actuation or HELB, the actions taken to restore ventilation during testing would be similar to those credited in the UFSAR. Can the EDG be considered available during the period the room vent fan is unavailable due to the fire protection surveillances?

Response No. The situation described is more complex than the few simple operator actions that current guidance allows to be excluded. Note: This response is consistent with FAQ 150 and should be applied to data covering 2Q2000 and forward.

ID 201

Posting Date 07/12/2000

Question (This FAQ is a replacement for FAQ 169. FAQ 169 has been withdrawn)

Are Technical Specification required monthly Emergency Diesel Generator surveillance tests counted as unavailability for this PI? Actions to restore the EDGs during surveillance testing could be considered complex. However, it seems unreasonable to count these required surveillance tests as unavailability, considering the fact that the EDG is powering the Engineered Safeguards bus in parallel with the grid for the majority of the test.

Response Yes, Technical Specification required monthly Emergency Diesel Generator surveillance tests are counted as unavailability for the SSU PI unless the test configuration is automatically overridden by a valid starting signal, or the function can be promptly restored either by an operator in the control room or by a dedicated operator stationed locally for that purpose. See NEI 99-02 Revision 0, page 26, lines 31 through 40.

ID 194

Posting Date 07/12/2000

Question Our site has two units, each of which has two trains of EAC with separate buses, for a total of four buses. There are four diesels on the site, and each diesel can be aligned to either unit, but are train specific. We are only required to have one diesel per train, for a total of 2 for the site, but PSA suggests that aligning each of the four diesels to its own bus is the preferred option. When one diesel is out for maintenance, we can align the other diesel in that train to both buses in the train, one bus in each unit. Technical Specifications do not limit the amount of time the plant can be in this configuration. SBO and Appendix R requirements do not impose any additional requirements on the number of diesels required per train nor do they add any additional requirements on the availability of a specific diesel unit.

We are counting unavailability for NRC indicators as follows: If an EAC bus does not have a diesel aligned to it in standby, then hours are counted for unavailability against that train. If a diesel is aligned in test to a bus, that is also counted as unavailability for that train because we cannot immediately restore the diesel nor does the diesel automatically start and supply the bus on a loss of power. If a diesel is aligned in test to both units, then it is counted as unavailability for both units. However, when a diesel is out of service for maintenance, it is not counted as unavailability if the alternate same-train diesel is aligned in standby to both buses in that train. We consider the extra diesel in each train as a maintenance train according to the rules in the NRC/NEI 99-02 guidance. Are we correct in the interpretation of these rules?

Response Based on the information provided, your interpretation of how to count diesel unavailable hours is correct. This configuration would be reported as a two-train system.

ID 169

Posting Date 07/12/2000

Question FAQ 169 has been withdrawn and replaced by FAQ 201.

Response .

ID 171

Posting Date 05/02/2000

Question Do hours associated with EDG improvements (e.g., cooling improvement modifications) have to be counted as unavailable hours if done for EDG improvement and in accordance with the Tech Spec AOT(our AOT is 14 days and is partly risk informed).

Response Yes.

ID 170

Posting Date 05/02/2000

Question We have not been counting technical specification required Emergency AC System surveillance testing as unavailability for the WANO performance indicators. The testing configuration is not automatically overridden by a valid starting signal and the function cannot be immediately restored, either by an operator in the control room or by a dedicated operator stationed locally for that purpose.Does historical data submitted Jan 21, 2000 for Emergency AC System safety system unavailability PI have to be corrected to take into account the additional unavailability?

Response No, the historical data does not have to be revised. However, data submitted for first quarter 2000 must comply with NEI 99-02.

ID 151

Posting Date 04/01/2000

Question Section 2.2, Mitigating Systems Cornerstone, Safety System Unavailability, Clarifying Notes, Hours Train Required states the Emergency AC power system value is estimated by the number of hours in the reporting period because emergency generators are normally expected to be available for service during both plant operations and shutdown. Considering only one train of Emergency AC power systems may be required in certain operational modes (e.g. when defueled), should actual required hours be determine for each train in place of using the default period hours? In certain operational modes it appears inconsistent to use period hours for hours required, yet not report the unavailable hours if a train is removed from service and Technical Specifications are still satisfied.

Response For the situation described it is acceptable to report the default value that is period hours.

ID 150

Posting Date 04/01/2000

Question Prior to performing surveillance testing, a Diesel Generator may be placed in an unavailable condition to allow for moisture checks. This may require opening all cylinder petcocks (test valves) and engaging the engine barring device. WANO guidance allows for not reporting unavailable hours provided the testing configuration can be quickly overridden within a few minutes by the control room or having operators stationed locally for that specific purpose. Does this condition require reporting unavailable hours to the NRC?

Response Yes. The situation described is more complex than the few simple operator actions that current guidance allows to be excluded.

Mitigating Systems

MS01 MS02 MS03 MS04 Mitigating Systems

ID 406

Posting Date 01/26/2006

Question **Appendix D (Catawba)**

Catawba
Nuclear Station (CNS) plans to refurbish the A and B trains of the Nuclear
Service Water System (NSWS) supply header piping. This refurbishment will
occur with both Unit 1 and Unit 2 at 100% power operation. CNS has submitted a
Technical Specification (TS) change for NRC approval to provide for a
completion time sufficient to accommodate the overhaul hours associated with
the refurbishment project.

The proposed TS changes will allow
the A and B Nuclear Service Water System (NSWS) headers for each unit to be
taken out of service for up to 14 days each for system upgrades. This will be
a one time evolution for each header. System upgrades include activities associated
with cleaning, inspection, and coating of NSWS piping welds, and necessary
system repairs, replacement, or modifications. It has been estimated that the work required in taking
the system out of service and draining the affected portions, will take
approximately 1 day. The affected sections of piping will be cleaned which
should take approximately 3 - 4 days. After cleaning, this evolution will
include inspection and evaluation of the NSWS piping. The inspection results
will be evaluated for repairs and/or coatings for the welds. After inspection,
the welds in the affected piping will be coated and allowed to cure. This
portion should take approximately 6 - 7 days. Upon completion, Operations will
be required to fill the NSWS, and perform any necessary post maintenance
testing which should take approximately 2 days. Therefore, the total time
should run from 12 - 14 days.

CNS desires to apply the overhaul
hour exemption to the NSWS supply pipe refurbishment project. The NSWS Improvement plan is divided into
three distinct
phases. The phase one of the plan specifically targets the stabilization of
the welds in the NSWS supply headers. Phase one includes activities
associated with cleaning, inspection, and coating of NSWS piping welds, and
necessary system repairs, replacement, or modifications. Civil engineering evaluations of the longitudinal and
circumferential welds in the supply headers have determined that the first
priority area for the initial phase should be main buried 42 inch supply
headers. These activities are being done to preclude any further degradation
of the affected welds. This will allow the second and third phases of the NSWS
Improvement Plan to commence with a predictable and reliable schedule.

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. 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

in accordance with the NEI guidance.

QUANTITATIVE RISK ASSESSMENT

Duke Power has used a risk-informed approach to determine the risk significance of taking a loop of NSWS out of service for up to 11 days beyond its current TS limit of 72 hours. The acceptance guidelines given in the EPRI PSA Applications Guide were used as a gauge to determine the significance of the short-term risk increase from the outage extension.

The current PRA model was used to perform the risk evaluation for taking a train of NSWS out of service beyond its TS limit. The requested NSWS outage does not create any new core damage sequences not currently evaluated by the existing PRA model. The core damage frequency contribution from the proposed outage extension is judged to be acceptable for a one-time, or rare, evolution. The estimated increase in the core damage probability for Catawba for each NSWS loop outage ranges from 2.7E-06 for a 2-day extension up to 1.5E-05 for an 11-day extension. Based on the expected increase in overall system reliability of the NSWS, an overall increase in the safety of both Catawba units is expected.

EXPECTED IMPROVEMENT IN PLANT PERFORMANCE

The increase in the overall reliability of the NSWS along with the decreased unavailability in the future because of the pipe repair project will result in an overall increase in the safety of both Catawba units.

NET CHANGE IN RISK AS A RESULT OF THE OVERHAUL ACTIVITY

Increased NSWS train unavailability as a result of this overhaul does involve an increase in the probability or consequences of an accident previously evaluated during the time frame the NSWS header is out of service for pump refurbishment. Considering the small time frame of the NSWS trains outage with the expected increase in reliability, expected decrease in future NSWS unavailability as a result of the refurbishment project, and the contingency measures to be utilized during the refurbishment project, net change in risk as a result of the overhaul activity is reduced.

Response For this plant specific situation, the hours for the nuclear service water support system refurbishment may be excluded from the computation of monitored system unavailability. Factors considered for this approval included an NRC approved Technical Specification change, results of a quantitative risk-assessment of the activity, the expected improvement in plant performance as a result of the work, and the net change in risk as a result of the work.

ID 373

Posting Date 11/18/2004

Question If the emergency AC power system or the residual heat removal system is not required to be available for service (e.g., the plant is in "no mode" or Technical Specifications do not require the system to be operable), is it appropriate to include this time in the "hours train required" portion of the safety system performance indicator calculation?

NEI 99-02, Revision 2, starting on line 25 of page 33, discusses the term "hours train required" as used in safety system unavailability performance indicators. For the emergency AC power system and residual heat removal system, the guidance allows the "hours train required" to be estimated by the number of hours in the reporting period because the emergency generators are normally expected to be available for service during both plant operations and shutdown, and because the residual heat removal system is required to be available for decay heat removal at all times.

Response The guidance on page 33 of NEI 99 02 states that the hours a train of either the emergency ac power system or the residual heat removal (RHR) system is required to be available may be estimated by the number of hours in the reporting period. This was based on the assumption that the emergency power system and the RHR system are required to be available at all times. However, in some situations, including some that have become more common recently (e.g. when a plant is defueled or while performing on line maintenance), the emergency ac power system, the RHR system, or both, may not be required to be available. However, the number of hours that a plant is in such conditions is generally very small in comparison to the number of hours in three years. Therefore it is acceptable for licensees to use the period hours as an estimate of the required hours to simplify data collection.

ID 361

Posting Date 04/22/2004

Question Appendix D
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

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.

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 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).

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.

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.

QUANTITATIVE RISK ASSESSMENT

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.

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:

- A train EDGs were protected throughout the evolution.
- The Unit 2 transformer yard was protected throughout the evolution.
- The A train equipment supported by RN was protected.
- No maintenance or testing on operable offsite power sources.
- All testing and maintenance on the operable train rescheduled to other time periods.
- No work or testing that could affect the SSF or SSF Diesel Generator.
- No work or testing that could affect the Turbine-Driven AFW Pump on Unit 2.

EXPECTED IMPROVEMENT IN PLANT PERFORMANCE

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.

NET CHANGE IN RISK AS A RESULT OF THE OVERHAUL ACTIVITY

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 For this case, the refurbishment of the nuclear service water system pumps on a specified interval , an exemption of the overhaul hours does not apply. Page 29 of NEI 99-02 , Revision 2 states that "(the) overhaul exemption does not normally apply to support systems except under unique plant-specific situations and on a case-by-case basis" and that "(t)he circumstances of each situation are different and should be identified to the NRC so that a determination can be made. FAQs 254, 315 and 337 resulted in exemptions for support system overhauls based on unique plant situations. For the Catawba service water piping replacements, information was provided that detailed the extensive nature of the work resulting in a significant amount of time that the support system would be unavailable, the need for Technical Specification changes, the affect on the monitored systems performance indicators (and impact due to the NRC Action Matrix),and the enhanced system performance expected for long term operations. For the Grand Gulf safety system water pump replacements, the work was performed to upgrade the pump material and the new pumps were expected to last the life of the plant. Several factors, including the information provided by the licensee (discussed above) and the items listed in NEI 99-02 (page 29 , lines 22 through 25), were taken into consideration. It is noted that since each case is unique, the list of factors to consider (in NEI 99-02) is not all inclusive.

The decision to not allow the exclusion of support system overhaul hours is based on several factors including that the work is a minor" overhaul type activity that is performed periodically to maintain reliable operation of the system and the hours cascaded into the four monitored systems have little impact on the margin to a threshold. As stated in FAQ 254, "...(the licensee understood) that there was a desire to eliminate exclusion of monitored systems unavailability hours caused by minor ' overhaul' type activities on supporting systems.

Mitigating Systems

MS01-MS04 Safety System Unavailability

ID 337

Posting Date 03/20/2003

Question **Appendix D - Catawba**

Catawba Nuclear Station plans to replace the Nuclear Service Water System (NSWS) A train header piping in January, 2003. This planned piping replacement is scheduled to occur when Unit 1 and 2 are at power operation and take approximately 141 hours to complete. A proposed tech spec amendment was submitted on 9/12/02 requesting a temporary change to certain tech specs that would allow the 'A' NSWS header for each unit to be taken out of service for seven days (168 hours) for pipe replacement. Duke requested NRC approval of the proposed amendment by 12/1/02; therefore, a tech spec with allowable outage time sufficient to accommodate the overhaul hours will be approved prior to support systems being taken out of service. Although the NSWS is not an NEI 99-02 system, 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 PIs affected by unavailability of the NSWS are Emergency AC, High Pressure Safety Injection, Residual Heat Removal, and Auxiliary Feedwater. If the hours that this overhaul of the NSWS made its supported systems unavailable cannot be excluded, it would result in reporting approximately 141 hours unavailability on 'A' train of each of the four monitored systems. This FAQ seeks approval to exclude the unavailability that will be incurred during this planned overhaul maintenance of the NSWS. 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."

QUANTITATIVE RISK ASSESSMENT

Duke Power has used a risk-informed approach to determine the risk significance of taking the 'A' loop of NSWS out of service for up to four days beyond 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 extension. The requested NSWS outage extension does not create any new core damage sequences not currently evaluated by the existing PRA model. The frequency of some previously analyzed sequences do, however, increase due to the longer maintenance unavailability of the 'A' NSWS loop. An evaluation of the Large Early Release Frequency (LERF) implications of the proposed 'A' loop NSWS outage extension concluded that they are insignificant. An evaluation was performed utilizing PRA for extending the NSWS technical specification time limit from 72 hours to 168 hours. The core damage frequency (CDF) contribution from the proposed outage extension is judged to be acceptable for a one-time, or rare, evolution. The resulting increase in the annualized core damage risk is 2.6E-06, a low-to-moderate increase in the CDF for consideration of temporary changes to the licensing basis and is acceptable based on consideration of the non-quantifiable factors involved in the contingency measures to be implemented during the overhaul. Therefore, because this is a temporary and not a permanent change, the time averaged risk increase is acceptable. Based on the expected increase in overall system reliability of the NSWS and the expected decrease in NSWS unavailability in the future as a result of the overhaul, an overall increase in the safety of both Catawba units is expect

EXPECTED IMPROVEMENT IN PLANT PERFORMANCE

The structural integrity of this section of NSWS piping is not in question at this time. The concern is that over time the pipe will degrade and eventually leak. The pipe replacement will enhance system integrity for long term operation and allow for detailed inspection and testing of the section of pipe removed. The removal of this section of pipe will allow for detailed analysis of how the degradation is occurring and provide information for managing the aging of this system. The proposed NSWS pipe replacement modification is expected to increase overall system reliability, thereby minimizing future system unavailability.

NET CHANGE IN RISK AS A RESULT OF THE OVERHAUL ACTIVITY

Increased NSWS train unavailability as a result of this overhaul does involve a one time increase in the probability or consequences of an accident previously evaluated during the time frame the NSWS header is out of service for pipe replacement. Considering the small time frame of the 'A' 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 to be utilized during the overhaul, net change in risk as a result of the overhaul activity is reduced.

Response For this plant specific situation, planned overhaul hours for the nuclear service water support system may be excluded from the computation of monitored system unavailabilities. 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.

ID 316

Posting Date 08/22/2002

Question As part of plant tour by an on-shift senior reactor operator, two covers were found to be missing for a piece of guard pipe used as a barrier over the main steam supply line to a Turbine Driven Auxiliary Feedwater pump. This guard pipe was designed to be used as a secondary barrier to prevent the spread of steam in the event of a steam supply line break to ensure environmental qualification of other plant equipment in the area. The covers provide access for inspection of the inner pipe and supports and are only needed for the postulated design basis rupture of that specific section of steam pipe.

The deficiency was easily corrected by replacement of the covers. The time of occurrence is associated with original plant construction and accordingly the deficiency has existed for a number of years.

Engineering reviews are still being performed and the impact on equipment qualification is still indeterminate. Can the fault exposure period for a construction/modification deficiency, as described above, that existed for a long period of time and that could not be identified by normal surveillance tests be addressed in the same fashion as a design deficiency hours described in NEI 99-02, Revision 2, Page 33, Lines 8 through 23?

Response Yes. While not specifically the result of a design deficiency, this construction caused equipment failure was not capable of being discovered during normal surveillance tests and has a long fault exposure periods thus meeting the same criteria as an excluded design deficiency. Its significance, like that of design deficiency, is more amenable to evaluation through the NRCs inspection process and thus should also be excluded from the unavailability indicators.

ID 315

Posting Date 08/22/2002

Question **Appendix D - Grand Gulf**

This question seeks an exemption from counting planned overhaul maintenance hours for a support system outage at the Grand Gulf Nuclear Station (GGNS).

At GGNS, the Safety System Water (SSW) system provides Ultimate Heat Sink supply for the ECCS systems, through three divisions:

* SSW A supplies Division 1 Emergency Diesel, Residual Heat Removal (RHR) A and Low Pressure Core Spray.

* SSW B supplies RHR B, RHR C and Division 2 Emergency Diesel.

* SSW C supplies High Pressure Core Spray (HPCS) and Division 3 Emergency Diesel.

The Emergency Diesels, RHR and HPCS are all Mitigating Systems and are monitored systems as defined in NEI 99-02. SSW is a support system as defined in NEI 99-02 and is monitored to the extent that it affects the monitored Mitigating Systems.

In 1994, periodic testing of the SSW pumps identified that shaft column fasteners had washers that had deteriorated to the point that the deep draft pump column had grown in length, allowing the impeller to rub on the bottom of the pump casing. The root cause determined that the washers had deteriorated due to galvanic corrosion set up by incompatible material between the pump shaft and the fasteners which was compounded by the poor water quality in the system. These fasteners were replaced on line in 1995 with like-for-like replacement of old materials while new pumps were designed and fabricated.

The 5-Year Business Planning process established 2002 for SSW A and B pump replacements and 2003 for the SSW C replacement. Work planning and business considerations determined that SSW A and SSW B pumps would be replaced in January and February 2002. Work planning also determined that the pumps could to be replaced on line within the Tech Spec LCO time (72 hours). Work duration was estimated to be 40 hours for each pump.

A quantitative risk analysis was performed. Due to the complexity and uniqueness of the work, the SSW outages were planned separately from the system outages they support. That is, no parallel Emergency Diesel or RHR outage work was to be scheduled with the SSW outages. The analysis showed that the planned configuration was acceptable from a Regulatory Guide 1.177 and 1.174 standpoint. For example, the incremental conditional core damage probability, ICCDP, is less than 1E-7, and the delta CDF (core damage frequency) is less than 2E-7/yr for this maintenance

SSW A and B pumps were changed in the first quarter 2002. Approximately 63 unavailable hours were incurred

in the work. As a result of pump change-out, the reliability of the SSW system will be improved as the upgrade in pump material will reduce the amount of fastener deterioration to a negligible level. The new pumps are expected to last the life of the plant and should reduce any future out of service time and inspection requirements due to the improved materials compatibility.

Based upon the above description, should the planned overhaul maintenance hours for the SSW system pump A and B replacements be counted in determining the PI values for Emergency Diesels, RHR and HPCS?

Response This activity qualifies as a unique plant specific situation as described in NEI 99-02 section for the Treatment of Planned Overhaul Maintenance. For this plant specific situation, the planned overhaul hours for the SSW system pump A and B replacements may be excluded from the computation of monitored system unavailabilities.

ID 312

Posting Date 06/12/2002

Question NEI 99-02, "Regulatory Assessment Performance Indicator Guidelines," under section 2.2 Mitigating Systems Cornerstone, provides the following guidance:
- The purpose of the safety system unavailability indicator is to monitor the readiness of important safety systems to perform their safety functions in response to off-normal events or accidents.

- Off-normal events or accidents are events specified in a plants design and licensing bases. These events are specified in a plants safety analysis report, however other event/analysis should be considered (e.g., Appendix R analysis)

- Hours required are the number of hours a monitored safety system is required to be available to satisfactorily perform its intended safety function.

- A train consists of a group of components that together provide the monitored functions of the system and as explained in the enclosures for specific reactor types. Fulfilling the design bases of the system may require one of more trains of a system to operate simultaneously.

- The specific reactor type enclosures provide figures that show typical system configurations indicating the components for which train unavailability is monitored. A statement is made that plant specific design differences may require other components to be included.

Plant specific design for the auxiliary feedwater, component cooling water, and essential service water systems provide Appendix R alternate shutdown capability to achieve safe shutdown from the unaffected unit through system cross ties. Our Technical Specifications (TSs) incorporate this Appendix R alternate shutdown capability. The focus of the TSs is on the availability of equipment to support the opposite unit when the opposite unit is operating.

Should the availability of Appendix R alternate shutdown capability be monitored and reported for safety system unavailability indicators?

Response No. Appendix R alternate shutdown capability is not monitored under these performance indicators.

ID 307

Posting Date 05/22/2002

Question For a single-train support system with redundant active components, does unavailability of one of the redundant active components require one of the trains of the monitored system to be considered unavailable?
Station Specifics: The component cooling (CC) water system provides a support function for the Residual Heat Removal (RHR) system. The RHR system provides both normal shutdown decay heat removal and decay heat removal during the containment sump recirculation phase of a design basis LOCA.

The CC system consists of a single loop with two 100% (redundant) pumps installed in parallel. Each pump is powered from a separate diesel backed bus. Under all license basis conditions (i.e. Chapter 14 analyses), a single pump is capable of providing 100% of the flow necessary to meet the design bases of the plant.

Similarly, multiple CC to Service Water (SW) heat exchangers are arranged in parallel, any one of which is fully capable of removing the accident design bases heat loads.

The station license considers the possibility of a temporary total loss of CC function due to a single passive failure during the long-term sump recirculation phase of an accident, and finds this acceptable since decay heat removal from containment is available via containment fan coil units. Does unavailability of a single pump and/or heat exchanger in the CC system constitute unavailability of a train of RHR, even though there is no intersystem train dependency?

Response No. Due to the redundant active components provided by the CC system design, the decay heat removal function of RHR is assured even when a single failure of a CC component has occurred. There is no intersystem train dependency with this design.

ID 302

Posting Date 02/28/2002

Question **Appendix D Hope Creek**

A 1 inch relief valve with an incorrect lift setpoint (120 psig instead of 150 psig) was installed in the Safety Auxiliaries Cooling System (SACS) (SACS performs the component cooling water function). With both pumps (A and C) in the train running, the relief valve lifted, resulting in loss of approximately 12-13 gpm of inventory. Normally, this amount of water loss could easily be made up by the demineralized water makeup system, which is capable of making up at the rate of 50 gpm.

During a loss of offsite power, the demineralized water makeup system is not available. When the SACS tank reaches the low-low level, the failure is indicated by the SACS LOOP TROUBLE alarm and a digital point, which displays and alarms on the plant computer, indicates that SACS EXPANSION TANK LEVEL is the issue. The low-low level alarm is an indication of system leakage; this information is provided in the procedure. As a result, no diagnosis is required; Control Room personnel are only required to provide a source of makeup water to ensure continued availability of SACS. The alarm response procedure refers the operator to the procedure for SACS Malfunction, which includes the instructions to perform emergency makeup from service water (verify a valve position and open three other valves from the control room), if required. Due to the amount of time (4.5 hours using the NRC assumptions, 5.9 hours using the utilities) between receipt of the alarm and the time that the expansion tank would become unavailable; it is likely that some diagnosis into the cause of the problem would occur; however, the use of emergency makeup from service water is available and does not require diagnosis. Should the time that the relief valve with the incorrect setpoint was installed be counted as fault exposure time for the supported systems?

Response No. NEI 99-02 states that analysis or sound engineering judgment may be used to determine the effect of support system unavailability on the monitored system. The following items should be considered when analysis or judgment is used to assess the effect of support system unavailability on the monitored system: were the risk/safety significant functions lost, is the condition recognizable, are recovery actions virtually certain to be successful, and is the analysis commensurate with the risk/safety significance of the issue.
The function would have remained available during all postulated accidents that did not include a Loss of Offsite Power. During a Loss of Offsite Power, the normal makeup water function would have been lost. This condition would have resulted in a low-low SACS tank level, which is alarmed in the Control Room as a SACS LOOP TROUBLE alarm, along with a digital point, which displays and alarms on the plant computer, indicating that SACS EXPANSION TANK LEVEL is the issue. At this point, the Operators would have time to respond to the alarm to prevent the loss of function. If the loss of function could not be prevented, the Operators could open 3 valves from the Control Room. Opening these 3 valves would restore SACS function by providing Service Water. This evolution is simple, does not require diagnosis, is proceduralized and trained on, and can be accomplished from the Control Room. In addition, other success paths were available. Some of these success paths included the need to perform diagnosis. However, in this case, there was sufficient time to perform this diagnosis and take the appropriate actions. It is virtually certain that at least one of the available success paths could have been performed in time to maintain the availability of SACS.

Therefore, because no risk/safety significant functions were lost, the condition would have been recognizable, the recovery actions are virtually certain to be successful, and an operability determination commensurate with the risk/safety significance of the issue was developed, no unavailability needs to be counted as a result of this incident.

ID 301

Posting Date 01/25/2002

Question **(This FAQ is a replacement for FAQ 293. FAQ 293 has been withdrawn)**

Appendix D - Quad Cities Station

On May 1, 2001, approximately 12 hours after initiation of the 24-hour surveillance test of the Unit 2 Emergency Diesel Generator (EDG), an alarm was received in the control room for low level in the diesel generator fuel oil day tank. The test was stopped and the situation was investigated. The investigation found that a solenoid valve in the fuel oil transfer line from the fuel oil transfer pump to the day tank had failed to open when required. The solenoid valve assembly was removed and the valve was overhauled. The solenoid valve assembly was reinstalled and the test was run again.

Approximately 12 hours into the second test, the alarm was received in the control room again for low level in the diesel generator fuel oil day tank. The test was continued, and the situation was investigated. Again, it was found that the solenoid valve in the fuel oil transfer line had failed to open. The operator, stationed locally at the EDG, opened a drain valve in the fuel oil transfer line and the solenoid valve then opened. The test was completed without further incident. The solenoid valve was subsequently replaced with a new solenoid valve rated for a larger wattage. The test was performed one final time without any problems.

The manual actions required to provide fuel oil to the EDG day tank in the event of failure of the fuel oil transfer system have the following attributes. They are noted in the UFSAR, they are included in station procedures, they are included in the training program, they are accomplished utilizing pre-staged equipment, there is no troubleshooting or diagnosis required, the initiating condition is annunciated in the control room, and they have been time validated against the time available. Additionally, although the safety function of the EDG system is risk-significant, the failure of one EDG is not.

Should unavailability time be reported for the failure of the Emergency Diesel Generator (EDG) fuel oil transfer system (FOT) solenoid valve?

Response No. Unavailable hours need not be reported for this situation. The actions are called out in the UFSAR, they are proceduralized, operators are trained regularly on the procedure, the necessary equipment is staged, no trouble shooting or diagnosis is necessary, there is a control room alarm to alert the operators to the need for action, and the actions have been demonstrated to be able to be accomplished within the necessary time constraints. Therefore, operator recovery actions are considered to be virtually certain of success.
When making this determination, the following factors, as appropriate, were considered:

1. NRC approval through an NOED, Technical Specification change, or other means
2. risk-significance of the support function(s)
3. Capability to recognize the support system unavailability
4. availability of personnel to perform the recovery actions
5. means o f communication between the control room and the local operators
6. frequency with which the recovery actions are performed
7. probability of successful completion of recovery actions
8. soundness of engineering analysis

ID 293

Posting Date 01/25/2002

Question FAQ 293 has been withdrawn and replaced by FAQ 301. The question and response text of FAQ 301 remains the same as the text previously held by 293. FAQ 301 reflects a change in applicability of the FAQ. The FAQ now applies to Quad Cities station solely.

Response

ID 297

Posting Date 12/13/2001

Question NEI 99-02 Reference: NEI 99-02 Rev. 1 on page 33 lines 25 through 28 states "Unavailable hours are also reported for the unavailability of support systems that maintain required environmental conditions in rooms in which monitored safety system components are located, if the absence of those conditions is determined to have rendered a train unavailable for service at a time it was required to be available."

Background information: Reference NRC Unresolved Item (URI) 50-454/455-00-14-01 for Byron Station from NRC Inspection Report 50-454/455-00-14, "Review of the licensees reporting of unavailability time for the emergency alternating current power system," which in part addressed the following. During review of performance indicator data for the emergency AC power system, the inspectors identified that the licensee had not included unavailability time for the 2B diesel generator (DG) on May 18, 2000, when the 2B DG ventilation fan was out-of-service (OOS) for maintenance to calibrate a differential pressure switch. The inspectors noted that the ventilation system was not able to perform its support function for the DG with the fan OOS and that DG room ventilation was necessary for sustained DG operation to ensure operability. Although the DG was declared inoperable and the appropriate Technical Specification limiting condition for operation was entered during this maintenance activity, the licensee did not consider the DG to be unavailable.

Discussion: Is the following interpretation of NEI 99-02 (revision 0 and revision 1) correct?

The phrase "...if the absence of those conditions is determined to have rendered a train unavailable..." implies that there must be an absence of those environmental conditions. The absence of those conditions would lead to a determination that the train would be considered unavailable. Byron Technical Requirements Manual (TRM) section 3.7.d (previously addressed as Byron Technical Specification 3/4.7.12) specifies the required environmental conditions required whenever the equipment in a room is required to be operable by specifying ambient temperature limits. The basis for these limits is that the area temperature limitations ensure that safety-related equipment will not be subjected to temperatures in excess of their environmental qualification temperatures. Exposure to excessive temperatures may degrade equipment and can cause a loss of its operability. Removing a room cooler or supporting ventilation system from service does not necessarily result in exceeding area temperature limits. As long as the required environmental conditions continue to be maintained there has not been an "absence of those conditions" and the monitored equipment would be considered available.

Response No, the interpretation is not correct. An evaluation must be performed to demonstrate that the monitored system is capable of performing its intended safety function under all conditions.

ID 292

Posting Date 12/13/2001

Question When reporting safety system unavailable time there are periodic evolutions that, although they may not be simple actions to restore a safety system, result in the safety system being unavailable for no more than several minutes. Is this level of tracking unavailable time required?

Response No. Evolutions or surveillance tests that result in less than 15 minutes of unavailability per train at a time should not be counted in unavailability data. The intent is to minimize unnecessary burden of data collection, documentation, and verification. Licensees should compile a list of surveillances/evolutions that meet this criterion and have it available for inspector review.

ID 291

Posting Date 11/15/2001

Question **Appendix D - Cook Nuclear Station**

Safety System Unavailability (SSU) indicators for Cook Units 1 and 2 are not calculated due to insufficient reported data. The SSU indicators and performance thresholds require 12 quarters of operational data to calculate unavailability and determine safety system performance. Cook Unit 1 returned to service December 18, 2000, after a 39-month forced outage and Unit 2 on June 25, 2000, after a 33-month forced outage. SSU indicator data has been reported for both units since the second quarter of the year 2000. Historical data was not reported since unavailability was not monitored during the extended outages. Cook Nuclear Plant (CNP) wants the SSU indicators to reflect actual safety system performance and have the indicators calculated with submitted data vice waiting until April 2003 for 12 quarters of data to be collected. What actions can be taken to have calculated SSU indicators and appropriately account for the effects of a T/2 fault exposure?

Response Submit a change report "zero-summing" the time prior to the 2Q2000 to provide for an indicator calculation. If a T/2 fault exposure occurs prior to obtaining 12 quarters of operational data, then the time would be reported in the comment field but not calculated for the SSU indicator. The inspection and SDP process would then evaluate the T/2 fault exposure.

ID 289

Posting Date 11/15/2001

Question A temporary cover was installed over the air intake damper to the emergency diesel generator ventilation system outside air intake damper.
1 Since manual action is required to remove the cover and permit the emergency diesel generator room ventilation system to perform its intended function, should unavailable hours be counted during the time the temporary cover was installed?

2. Do the criteria for determining unavailability, as described in NEI 99-02, Revision 1, page 24, lines 24-33, apply to this situation?

Response 1. Yes, the unavailable hours should be counted because the operator recovery actions were not determined to be virtually certain to be successful under accident conditions.

2. No. The guidance in NEI 99-02 Revision 1, page 24, lines 24 through 33 only apply to test configurations and this was not a test configuration.

ID 290

Posting Date 10/31/2001

Question Should surveillance testing of the safety system auto actuation system (e.g. Solid State Protection System testing, Engineered Safety Feature testing, Logic System Functional Testing) be considered as unavailable time for all the affected safety systems? During certain surveillance testing an entire train of safety systems may have the automatic feature inhibited.

Response Yes. Restoration action involves diagnosis using Emergency Operating Procedures to restore design basis functions.

ID 278

Posting Date 07/12/2001

Question **Appendix D: Prairie Island**

At Prairie Island, the three safeguards Cooling Water (service water) pumps were declared inoperable for lack of qualified source of lineshaft bearing water. This required entry into Technical Specifications 3.0.c (motherhood). The plant requested and received a Notice of Enforcement Discretion (NOED) that allowed continued operation of both units until installation of a temporary modification to provide a qualified bearing water supply to two of the three pumps was complete (14 days). Compensatory measures were implemented to ensure continued availability of water to the lineshaft bearings.

The Cooling Water System is required to mitigate design basis transients and accidents, maintain safe shutdown after external events (e.g. seismic event), and maintain safe shutdown after a fire (Appendix R).The only events for which the Cooling Water System function could have been compromised are the loss of off-site power (LOOP)

and a design basis earthquake (DBE). These two events are limiting because they both involve the loss of off-site power. If off-site power continues to power the non-safeguards buses, then the Cooling Water System function is not lost.

Our Risk Assessment determined that the initiating event frequency for a DBE during the 14 day NOED period was so low that it was not a concern. Therefore, this discussion will focus on the LOOP event. The bearing water supply was not fully qualified for LOOP because the power to the automatic backwash for strainers in the system was not safeguards. The concern was that system strainers would plug eventually. However, for this initiating event, function is not lost immediately it takes time for the strainers to plug. The time it takes is a function of river water quality. Based on an estimate of worst-case river water quality, there are 4 to 7 hours before function would be lost (strainers plug). In fact, testing around the period of the event, showed river water quality was such that the strainers did not plug after 48 hours. Given the time available there is high probability that operators could complete recovery actions before function was lost. A specific probabilistic risk assessment of the local operator actions determined that the probability of failure was less than 1%.

The NOED was requested to preclude a two unit shutdown. As part of the request for the NOED, compensatory measures to assure that the Cooling Water System function is maintained were proposed. In summary, the compensatory measures were to:

* use a hose (pressure-rated) to connect a safety related source of Cooling Water to the lineshaft bearing supply piping for a Cooling Water Pump

* post a dedicated operator locally in the screenhouse near the Cooling Water Pumps

* pre-stage equipment and tools in the screenhouse

* place identification tags at the connection locations

* train the dedicated operator(s) on the procedure for connecting the hose.

The need to implement the compensatory measures would have been identified to the Control Room operator by a loss of bearing flow alarm. As stated earlier, this condition is not expected to occur until a filter becomes plugged 4 to 7 hours after the loss of off site power. The Control Room operator would notify the dedicated operator to perform the procedure. The walkdown of the procedure determined that bearing flow could be established in less than 10 minutes. The pump is capable of operating for approximately one hour without bearing flow. When bearing flow is established, the Control Room alarm will clear, thereby giving the Control Room operator confirmation that the procedure has been performed. The procedure also required an independent verification of the bearing flow restoration within one hour of receiving the loss of bearing water flow alarm.

The Cooling Water System is a support system and its unavailability affects: High Pressure Safety Injection, Auxiliary Feedwater, Residual Heat Removal, and Unit 1 Emergency AC (Unit 2 Emergency AC is cooled independent of Cooling Water). Using NEI 99-02 criteria, Prairie Island included the time that the Cooling Water Pumps were declared inoperable, approximately 300 hours, as unplanned unavailability in our PI data report. This resulted in two White Indicators (one on each unit), two other systems (one per unit) on the Green/White threshold, and two systems (again, one per unit) close to the Green/White threshold. However, the cause for these Performance Indicators changing from Green to White is a direct result of the lack of qualified bearing water to the Cooling Water pumps. The lack of qualified bearing water was evaluated through the SDP and resulted in a White finding. A root cause evaluation was performed and corrective actions identified. Since the change in the performance Indicators from Green to White was a direct result of the unqualified bearing water, no additional corrective action is planned.

This event does not fit into the guidance given in NEI 99-02. In Rev. 0, page 26, the Clarifying Notes address testing and Control Room operator actions. In Rev. 1, page 28, the Clarifying Notes only allow operator actions taken in the Control Room. We have also reviewed Catawbas FAQ 254. However, their situation addressed maintenance activity results not operator action.

Initially, unavailable hours were recorded from the time of discovery until completion of a Temporary Modification that provided a qualified bearing water supply. This resulted in counting approximately 300 unavailable hours per pump. Since the compensatory actions would have maintained the Cooling Water System function, should the unavailable hours be counted only from the time of discovery until the compensatory measures were in place?

Response Yes, the unavailable hours should be counted only from the time of discovery until the time that the compensatory measures were in place and remained in place. The actions required to restore the Cooling Water System function were simple and had a high probability of success. This is based upon the following factors:
* A probabilistic risk assessment of the local operator actions calculated less than a 1% probability of failure.

* There is control room alarm to alert the Control Room operator of the need for the compensatory measures.

* There are at least two means of communication between the Control Room and the local operator.

* Recovery action for each pump was simple - connect a hose to two fittings and position two valves.

* Time to complete the recovery action was estimated to be about 10 minutes, based on walk-throughs. Failure to successfully complete the recovery action was not expected to preclude the ability to make additional attempts at recovery.

* A dedicated operator was stationed in the area to complete the recovery action.

* The operator had a procedure and training for accomplishing the recovery action.

* All necessary equipment for recovery action was pre-staged and the fittings and valves were readily accessible.

* Indication of successful recovery actions was available locally and in the Control Room.

Note: This FAQ is specific to the plant and the circumstances, which included NRC approval of compensatory measures and an SDP review. Other licensees should not unilaterally apply this FAQ result, but should submit a plant specific FAQ.

ID 271

Posting Date 05/31/2001

Question Page 4 of NEI 99-02 states: "The guidance provided in Revision 0 to NEI 99-02 is to be applied on a forward fit basis...", however there is also a provision to reset fault exposure hours (page 29) that requires 4 quarters have elapsed since discovery. If reset of fault exposure is applied to historical data submitted under the "best effort" collection method (i.e. grandfathered data previously collected under INPO 98-005 guidelines), does this constitute a backfit of the NEI 99-02 guidance? Additionally, if the reset of fault exposure hours does constitute a backfit, would the station then be required to revise all of the historical data to conform with all 99-02 requirements?

Response If the conditions have been met to reset fault exposure hours, in accordance with NEI 99-02, for fault exposure hours experienced during the historical data period, the hours can be reset without having to revise the remaining historical data to conform with all 99-02 requirements. However, because the green/white threshold was not crossed, the fault exposure hours cannot be removed.

ID 265

Posting Date 05/02/2001

Question NEI 99-02 states "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. Credit for a dedicated local operator can be taken only if (s)he is positioned at the proper location throughout the duration of the test for the purpose of restoration of the train should a valid demand occur". Station Results and Test personnel are qualified to perform valve lineups and are in the control room and/or stationed locally during testing. Do the R&T personnel with the written test procedure meet the guidance of NEI 99-02 for being able to restore equipment to service when needed and thus not counting the testing time as planned unavailable hours?

Response Yes, provided the plant personnel are qualified and designated to perform the restoration function and are not performing any restoration steps for which they are not qualified. The Station considers the restoration steps of the test procedures to be the "written procedure" for the required "restoration actions". The qualified R&T personnel (rather than a dedicated operator) with the test procedures allow the Station to take credit for restoration actions that are virtually certain to be successful during accident conditions while performing tests and thus this time should not count towards Planned Unavailable Hours.

ID 261

Posting Date 04/04/2001

Question Concerning removal of fault unavailable hours NEI 99-02 states: "Fault exposure hours associated with a single item may be removed after 4 quarters have elapsed from discovery"
In the case we are considering, the hours were discovered in the third calendar quarter. When do the four elapsed quarters begin? At the start of the fourth calendar quarter? and end at the conclusion of next years third quarter?

If the period of calculation of the indicator value was only four calendar quarters beginning the quarter after they occurred, and the fault unavailable hours are reported in the quarter in which they occurred, whats the point in removing them after they are no longer a factor in the calculation of the indicator?

"Fault exposure hours are removed by submitting a change report that provides a revision to the reported hours for the affected quarter(s). The change report should include a comment to document this action."

Response The fault exposure hours should be reported for third quarter data and may be removed with the submittal of the next years third quarter data provided the criteria for removing fault exposure hours are met.
All safety system unavailability performance indicators calculate train unavailability for 12 quarters. Therefore, the situation you describe would not exist.

ID 254

Posting Date 02/08/2001

Question **Appendix D Catawba**

A recently issued FAQ for the NRC Performance Indicators Program revised the positions taken for unavailability associated with planned overhaul hours. FAQ 178 was withdrawn from NEI 99-02 and replaced with FAQ 219. The new FAQ, effective for fourth quarter reporting, adds two clarifying questions and answers to the previous FAQ 178. These two additional items are:

Q. What is considered to be a major component for overhaul purposes?

A. A major component is a prime mover - a diesel engine or, for fluid systems, the pump or its motor or turbine driver or heat exchangers.

Q. Does the limitation on exemption of planned unavailable hours due to overhaul maintenance of "once per train per operating cycle" extend to support systems for a monitored system?

A. For this indicator, only planned overhaul maintenance of the four monitored systems (not to include support systems) may be considered for the exemption of planned unavailable hours.

At Catawba Nuclear Station, periodic testing indicated that crud and rust accumulation in the Nuclear Service Water System (NSWS) headers and piping was reducing water flow. To restore the water flow and the prevent further deterioration of the headers and piping, a refurbishment project was planned to clean the system, replace part of the piping, and rearrange certain piping access to the headers to avoid water stagnation. Since the NSWS is a shared system between both Catawba units, it was decided that the optimum time to perform this work would be while Unit 1 was in a refueling outage and Unit 2 was at power. This project included both "A" and "B" redundant trains of the system and was sequenced independently during the recent Catawba Nuclear Station Unit 1 End of Cycle 12 (1EOC12) refueling outage. Approximately 8,000 feet of piping was cleaned that included 4,260 feet of 42 inch, 760 feet of 30 inch, 330 feet of 24 inch, 660 feet of 18 inch, 1,935 feet of 10 inch, and 100 feet of 8 inch. Due to the extensive nature of the work performed, each train of NSWS was unavailable for approximately ten days.

Applicable technical specifications were revised through the standard NRC approval process (reference Amendment No. 189 to FOL NPF-35 and Amendment No. 182 to FOL NPF-52 approved October 4, 2000) to allow this project to be performed. These amendments allowed specific systems, including mitigating systems monitored under the NRC performance indicator program, to be inoperable beyond the normal technical specification allowable outage times (AOT) of 72 hours for up to a total of 288 hours on a one-time basis. A significant part of the justification for the license amendment request was a discussion of the risk assessment of the proposed change and the NRC concluded in the SER that the results and insights of the risk analysis supported the proposed temporary AOT extensions.

The NSWS itself is not a monitored system under the performance indicators; however, 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 contained in the Mitigating Systems Cornerstone and include: Emergency AC Power System Unavailability, High Pressure Safety Injection System Unavailability, Auxiliary Feedwater System Unavailability, and Residual Heat Removal System Unavailability. If the hours that this overhaul of the NSWS made its supported systems unavailable cannot be excluded from reporting under the performance indicators, it will result in Catawba Unit 2 reporting two white indicators for the 4Q2000 data. These two white indicators for Emergency AC Power System Unavailability and Residual Heat Removal System Unavailability would result in a degraded cornerstone situation as defined in the NRC Action Matrix. Additionally, since these indicators are twelve quarter averages, carrying these hours for the next three years would result in decreased margin to the white/yellow threshold and greatly increase the consequences of additional unavailable hours that might occur during that period of time.

Based on input from NRC and NEI individuals who participated in discussions related to FAQ 219, Duke Energy understands that there was a desire to eliminate exclusion of monitored systems unavailable hours caused by minor "overhaul" type activities on supporting systems. However, it seems unreasonable to require reporting of unavailable hours for situations such as this when the overhaul activities are extensive enough to have required NRC review and approval of a change in technical specifications to allow the increased AOT.

Should this situation be counted?

Response For this plant specific situation, the planned overhaul hours for the nuclear service water support system may be excluded from the computation of monitored system unavailabilities.
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.

ID 252

Posting Date 02/08/2001

Question How should "t over 2" Fault Exposure time be counted for an installed spare?

Response If a failure is discovered in equipment that is or has been credited as an installed spare, the appropriate way to estimate fault exposure hours is to count from the date of failure back to one half the time since the last successful operation and include only those hours during that period when the equipment was required to be available.

ID 247

Posting Date 02/08/2001

Question NEI 99-02 Revision 0 defines criteria for determining availability during surveillance testing. This definition can be found on page 26. It allows operator action to be credited for the declaration of availability. NEI 99-02 also defines criteria for determining fault exposure. This definition can be found on pages 28 & 29. Line 5, page 29 references operator action. It states, "Malfunctions or operating errors that do not prevent a train from being restored to normal operation within 10 minutes, from the control room, and that do not require corrective maintenance, or a significant problem diagnosis, are not counted as failures." In addition, page 29, line 13, states, "A train is available if it is capable of performing its safety function."
If the fault can be corrected quickly (much less than 10 minutes) by a single operator action that is contained in a written procedure, is uncomplicated, and does not require diagnosis or repair, but the operator action cannot be shown to satisfy auto-start time design assumptions (e.g., HPCI injection within 45 seconds), should fault exposure hours be assigned to a failure?

Response Operator actions to recover from an equipment malfunction or an operating error can be credited if the function can be promptly restored from the control room by a qualified operator taking an uncomplicated action (a single action or a few simple actions) without diagnosis or repair (i.e., the restoration actions are virtually certain to be successful during accident conditions). (Note that under stressful, chaotic conditions, otherwise simple multiple actions may not be accomplished with the virtual certainty called for by the guidance. For example, some manual operations of systems designed to operate automatically, such as manual control of the HPCI turbine to establish and control injection flow, are not virtually certain to be successful.) NEI 99-02 will be revised to reflect this FAQ response.

ID 241

Posting Date 01/10/2001

Question NEI 99-02 Revision 0, states the following regarding Planned Unavailable Hours:
"Testing, unless the test configuration is automatically overridden by a valid staring signal or the function can be promptly restored either by an operator in the control room or a dedicated operator stationed locally for that purpose. Restoration actions must be contained in a written procedure, must be uncomplicated (a simple action or a few simple actions) and must not require diagnosis or repair. Credit for a dedicated operator can be taken only if (s)he is positioned at the proper location throughout the duration of the test for the purpose of restoration of the train should a valid demand occur. The intent of this paragraph is to allow licensees to take credit for restoration action that are virtually certain to be successful (i.e. probability nearly equal to 1) during accident condition

The question is whether normal surveillance test restoration steps (normally used to re-align the system after the surveillance testing is complete) are adequate to satisfy the requirements for a "written procedure."

Example: The Low Pressure Injection (LPI) surveillance procedure (SP) has the LPI pump discharge aligned to the "recirculation line" and flowing to the Borated Water Storage Tank. Closing one motor operated valve (MOV), if an accident were to take place, would isolate this flow path. The MOV would be closed from the control room. The restoration actions for the SP have closure of this valve as part of the normal plant restoration. In this case, CR-3 engineering personnel believe that the restoration instructions in the surveillance procedure are adequate to meet the intent of a "written procedure" identified in the above paragraph from NEI 99-02.

Response Yes, normal surveillance test restoration steps are adequate to satisfy the requirements for a written procedure. A separate restoration procedure need not be prepared.

ID 239

Posting Date 01/10/2001

Question **This FAQ is a replacement for FAQ 190. FAQ 190 has been withdrawn.**

The guidance in NEI 99-02 states that fault exposure hours may be removed after certain criteria are met. One criterion is that supplemental inspection activities by the NRC have been completed and all open items have been closed out. If a licensee has fault exposure hours that meet all other stated criteria (>336 hours, corrective actions completed, and four quarters have elapsed) but the indicator is still green, does the baseline inspection count in place of the supplemental inspection? Also, please clarify the intent of the phrase after 4 quarters have elapsed from discovery.

Response 1. No. Fault exposure hours may be removed only if the indicator is outside the green band so that supplemental inspection is necessary (and all other stated criteria are met). The intent of this provision was to allow the removal a large number of fault exposure hours due to a single event or condition so that a licensee would not be outside the green band for an extended time period. There are two reasons for this: (1) after the stated criteria are met, the PI is no longer considered to be indicative of current performance; and (2) unavailable hours accumulated later would put the licensee further into the white band but would not trigger any further NRC action, since the white band is 1.5 to 2 times as wide as the green band. For these reasons, the hours may be removed to reset the indicator so that further fault exposure hours could trigger further NRC response.
2. The intent of the phrase after 4 quarters have elapsed from discovery was that the indicator would be non-green for 4 quarters minimum, regardless of when the corrective actions were completed and the supplemental inspection closed out. The quarter in which the fault exposure hours is identified would be the first non-white quarter, and 12 months (four quarters) later, assuming all required conditions are met, the hours could be removed from the calculation for that quarter.

ID 190

Posting Date 01/10/2001

Question FAQ 190 has been withdrawn and replaced by FAQ 239.

Response

ID 224

Posting Date 10/31/2000

Question Our Standby Service Water System (SSW) is designated as a Support System for each of the four mitigating systems. The system has two trains and each train has two 50% capacity pumps. At the mitigating system interface, the SSW support system either has both trains of SSW supplied to the cooling load or one SSW train exclusively supplying the cooling load. A train with one pump in service will supply the required SSW loads except the RHR train. The RHR train is normally valved out of service and is manually lined up to support a design basis accident condition some time after the automatic initiation sequence is completed. We consider all mitigating systems within a train, except RHR in that train, available with one SSW pump out of service. However, RHR, with the SSW from the other train available, is considered available. Have we calculated the availability correctly?

Response Yes. The mitigating systems that can be supplied by a single SSW train with one SSW pump in service are available.

ID 219

Posting Date 10/01/2000

Question (This FAQ is a replacement for FAQ 178. FAQ 178 has been withdrawn)

FAQ on Planned Overhaul Hours

The concept of not counting major on-line overhaul hours against the SSU performance indicator is sound. It allays a prevalent concern that a licensee could end up with a white indicator, and potentially a degraded cornerstone, primarily due to performing on-line maintenance that is considered in PSA analyses and bounded by the Tech. Spec. AOT, and has been determined to be a good business practice [to reduce outage length, etc.]. To ensure consistency of reporting and inspector oversight, the following issues should be addressed:

1. What defines overhaul versus non-overhaul maintenance?

2. What is considered to be a major component for overhaul purposes?

3. Is application of planned overhaul hours limited to systems for which a risk informed AOT extension has been approved?

4. Is there a limit to the number of planned overhaul outages a licensee can report on a given system / train?

5. Can an overhaul be performed in two segments in separate AOTs during an operating cycle?

6. If an overhaul maintenance interval is scheduled to take 120 hours, but the actual unavailable interval is greater [say 140 hours] but still bounded by T.S. AOT, can the entire interval be designated as planned overhaul hours, or is only the scheduled interval appropriate?

7. Can additional non-overhaul maintenance be performed during a planned overhaul maintenance interval?

8. Can Major rebuild tasks necessitated by an unexpected component failure be counted as overhaul maintenance? [Example: RHR pump wipes a motor bearing during surveillance run. It is decided to pull PM activities ahead to replace the motor with a spare.]

9. Does the limitation on exemption of planned unavailable hours due to overhaul maintenance of once per train per operating cycle extend to support systems for a monitored system?

Response 1. NOTE: This answer applies to how unavailable hours are counted for PI purposes. It does not establish or recommend any changes in regulatory requirements or licensee maintenance actions. This FAQ is a clarification and applies to data submittals covering 4Q2000 data and beyond.Overhaul maintenance comprises those activities that are undertaken voluntarily and performed in accordance with an established preventive maintenance program to improve equipment reliability and availability. Overhauls include disassembly of major components and may include replacement of parts as necessary, cleaning, adjustment, lubrication as necessary, and reassembly.

2. A major component is a prime mover - a diesel engine or, for fluid systems, the pump or its motor or turbine driver or heat exchangers.

3. No. Any AOT sufficient to accommodate the overhaul hours may be considered. However, to qualify for the exemption of unavailable hours, licensees must have in place a quantitative risk assessment. This assessment must demonstrate that the planned configuration meets either the requirements for a risk-informed TS change described in Regulatory Guide 1.177, or the requirements for normal work controls described in NUMARC 93-01, Section 11.3.7.2. In addition, all other requirements described in the response to this FAQ must be met. Otherwise the unavailable hours must be counted. The Safety System Unavailability indicator excludes maintenance-out-of-service hours on a train that is not required to be operable per technical specifications (TS). This normally occurs during reactor shutdowns. Online maintenance hours for systems that do not have installed spare trains would normally be included in the indicator. However, some licensees have been granted extensions of certain TS allowed outage times (AOTs) to perform online maintenance activities that have, in the past, been performed while shut down. Acceptance guidelines for such TS changes are given in Sections 2.2.4 and 2.2.5 of Regulatory Guide 1.174 and Section 2.4 of Regulatory Guide 1.177. These guidelines include demonstration that the change has only a small quantitative impact on plant risk (less than 5x10-7 incremental conditional core damage probability). It is appropriate and equitable, for licensees who have demonstrated that the increased risk to the plant is small, to exclude unavailable hours for those activities for which the extended AOTs were granted. However, in keeping with the NRCs increased emphasis on risk-informed regulation, it is not appropriate to exclude unavailable hours for licensees who have not demonstrated that the increase in risk is small. In addition, 10 CFR 50.65(a)(4), which goes into effect on November 28, 2000, requires licensees to assess and manage the increase in risk that may result from proposed maintenance activities. Guidance on a quantitative approach to assess the risk impact of maintenance activities is contained in the latest revision of Section 11.3.7.2 (dated February 22, 2000) of NUMARC 93-01, Revision 2. That section allows the use of normal work controls for plant configurations in which the incremental core damage probability is less than 10-6. Licensees must demonstrate that their proposed action complies with either the requirements for a risk-informed TS change or the requirements for normal work controls described in NUMARC 93-01.

4. Yes. Once per train per operating cycle.

5. Yes, provided that no more than two segments be used and the total time to perform the overhaul does not exceed one AOT period.

6. If the unavailability is caused by activities designated as planned overhaul maintenance, the hours should not be counted in the unavailability indicator. If the additional unavailability is caused by a failure that would prevent the fulfillment of a safety function, the additional hours would be non-overhaul hours and/or potential fault exposure hours, and would count toward the indicator. (Also, see footnote 3 page 26 Rev 0.)

7. Yes, as long as the outage duration is bounded by overhaul activities, other activities may be performed. If the overhaul activities are complete, and the outage continues due to non-overhaul activities, the additional hours would be non-overhaul hours and would count toward the indicator.

8. No.

9. For this indicator, only planned overhaul maintenance of the four monitored systems (not to include support systems) may be considered for the exemption of planned unavailable hours.

ID 178

Posting Date 10/01/2000

Question FAQ 178 has been withdrawn and replaced by FAQ 219.

Response

ID 199

Posting Date 07/12/2000

Question SSES has 5 diesel generators, 4 are required to support operation of both units and the fifth is an installed spare capable of substituting for any one of the other 4. We perform diesel generator overhauls with the units on line by swapping in the spare for the overhauled diesel to maintain the required number of 4. No unavailable time is charged during the overhaul. However, following the overhaul we perform post maintenance testing and are in a 72-hour LCO until the overhauled diesel is declared operable. We have previously counted this post maintenance testing time as unavailable.

In light of the new FAQ's approved on 5/24...particularly as FAQ 178 on Planned Overhaul hours would apply to our unique design...is it the intent of this PI to include the post maintenance testing time following a planned overhaul as unavailable hours?

Response Not if the diesel passes the test and the requirements of the paragraph that starts on line 31 of page 26 of NEI 99-02 are met. If the diesel fails the test, the entire test time would be counted as unavailable time, or any portions of the test that do not meet the requirements of the cited paragraph would be counted as unavailable time.

ID 192

Posting Date 06/14/2000

Question Does the response to FAQ #88 mean that engineering judgement is equivalent to and can be used in lieu of component failure analysis, circuit analysis, or event investigation?

Response The intent of the use of the term with certainty is to ensure that an appropriate analysis and review to determine the time of failure is completed, documented in your corrective action program, and reviewed by management. The use of component failure analysis, circuit analysis, or event investigations are acceptable. Engineering judgement may be used in conjuction with analytical techniques to determine the time of failure.

ID 191

Posting Date 06/14/2000

Question Our station has several areas containing a variety of safety system components from multiple safety systems and both trains (motor operated valves, instrumentation, pumps, etc.). Examples are the auxiliary building general area, pipe chases, penetration rooms, etc. These general areas are cooled by what we refer to as area coolers and there is an A train and a B train cooler for each area, both fed from opposite divisions of class 1E power and separate trains of cooling water. Additionally, these fans have 100% capacity (each) to maintain the required temperature for the area; i.e., these could be viewed as installed spares. As far as support systems to the fan, with one train of area cooling out of service, it would require a loss of 2 off-site power supplies coincident with the specific train of diesel generator power and cooling to render the remaining train of area cooling unavailable.

Based on the guidelines given in NEI 99-02, R0, section 2.2, "Support System Unavailability", we interpret this to mean that if we remove one train of area cooling, it would not constitute any safety system unavailability.

Is this a correct interpretation?

Response Yes. In this case, as described above, the removal of one train of area cooling would not constitute safety system unavailability if the other fan maintains environmental conditions. See NEI 99-02, page 33, lines 25 through 28.

ID 187

Posting Date 06/14/2000

Question Under "Support System Unavailability" of NEI-99-02 the statement is made that: "for monitored fluid systems with components cooled by a support system, where both the monitored and support system pumps are powered by a class 1E (i.e. safety grade or equivalent) electric power source, cooling water supplied by a pump powered by a normal (non-class 1E--i.e., non-safety-grade) electric power source may be substituted for cooling water supplied by a class 1E electric power source, provided that redundancy requirements to accommodate single failure criteria for electric power and cooling water are met. Specifically, unavailable hours must be reported when both trains of a monitored system are being cooled by water supplied by a single cooling water pump or by cooling water pumps powered by a single class 1E power (safety-grade) source". We are defining our system boundary for the reported system to include the breaker/ switchgear providing power to the reported system's pumps/valves, etc. The main switchgear/breakers are installed in the safety switchgear panels that are cooled by a common area cooling system. This cooling system is safety grade, as cooling is required following a design basis accident from a safety grade source. The cooling system has two fan coil units, using safety chilled water in each coil, a train A (&powered by train A 1E power) and a train B unit (powered by safety grade train B 1E power). Therefore cooling for the portions of the reported systems installed in the safety Switchgear panel is provided by redundant, class 1E powered, safety grade unit coolers (train A and B).

The coolers discharge to a common plenum, which in turn cools the separate switchgear rooms. Each cooler (train A and B) has 100% capacity for cooling all (train A, B, and AB) switchgear. At our site there are currently no technical specification associated with these coolers, although we have imposed a 72 hour limitation for removing one cooler (in either train) from service in our technical requirements manual (TRM), as well as a one hour shutdown action statement if both coolers (trains) are inoperable. However, since no technical specifications exist, we do not cascade inoperability or unavailability of the unit coolers into the switchgear themselves, one reason being since the cooling duct system is common to all switchgear it is impractical to cascade. In light of the above quoted statement in the NEI document, are we required to report unavailability hours in one or more trains of the reported systems, cascaded from removal of one train of the switchgear cooling system from service (i.e.

removal of one of the two, redundant, fan coil units from service).

Response No. In this case, as described above, the removal of one train of area cooling would not constitute safety system unavailability if the other fan maintains environmental conditions. See NEI 99-02, page 33, lines 25 through 28.

ID 181

Posting Date 05/24/2000

Question Can Improved Technical Specification criteria be used to reevaluate system unavailability incurred in prior years under the previous technical specifications?
If the actual plant conditions at that time met the requirements of the current Improved Technical Specifications, can credit for functionality be taken for that past period?

Response No. The conditions and requirements in place at the time should be used to determine system unavailability.

ID 179

Posting Date 05/24/2000

Question NEI 99-02 allows historical data submitted data to be revised to reflect current guidance if desired. Draft D of NEI 99-02 allowed the submittal of WANO data as reported to WANO. Can major overhaul maintenance unavailable hours be removed from the historical data submitted without additional modifications to the WANO data? Or do other aspects of Revision 0 that are different from WANO reporting have to be considered concurrent with removal of the major overhaul maintenance unavailable hours? For example, in the EAC PI, if it was desired to remove from previously submitted data the overhaul maintenance unavailable hours per revision 0 would I also need to research and modify (if necessary) the historical data to account for limitations of operator action usage that are expected in NRC PI reporting, yet different from WANO reporting?

Response Revision 0 of NEI 99-02 may be used on a PI by PI basis for data submitted prior to 2Q2000 provided that a best effort is made to apply all the guidance in Revision 0 that applies to the PI. For the example stated in the question, the overhaul hours may be removed provided other guidance in NEI 99-02 Revision 0 related to fault exposure, credit for operator actions, etc. is also applied on a best effort basis.

ID 175

Posting Date 05/02/2000

Question NEI 99-02 describes the requirements for including testing as planned unavailable hours for safety system unavailability. In this, credit is allowed for a dedicated local operator only if they are positioned at the proper location throughout the duration of the test for the purpose of restoration of the train should a valid demand occur. If the operator dedicated to conducting the test is in the proper location, and has no other duties other than to conduct the test and to restore from the test in the event of a valid demand, then does that operator meet the requirements of this paragraph, or does an additional operator need to be stationed for the sole purpose of restoration. Note that the operator conducting the test has no other duties when a valid demand is received than to restore the system, and the written guidance for restoration is embedded in the test procedure and in his possession during the testing.

Response The operator performing the test meets the requirements, provided the additional conditions for exclusion of testing hours, identified on page 26 of NEI 99-02, are met.

ID 168

Posting Date 05/02/2000

Question Assume a recirculation spray pump tested poorly and had only previously been tested 2 years ago. Per the NEI 99-02 FAQ I believe I am to go back and revise the fault exposure hours for these quarters. Should I zero out any other unavailability for those months, since the accumulation of unavailability could be greater than the hours required?

Response Remove the double count by removing the planned and unplanned hours which overlap with the fault exposure hours. Put an explanation in the comment field. If you later remove the fault exposure hours, restore the hours which had been removed.

ID 167

Posting Date 05/02/2000

Question Does planned preventive maintenance (PM) or corrective maintenance (CM) on support systems have to be taken as Planned Unavailable Hours for the supported system? Page 22, lines 9 - 33 infers that any PM or CM must be credited as Planned Unavailable hours.

One example is a site where there are four EDGs. Each EDG has two approximate 50% fuel oil tanks. The fuel oil tanks are a support system for the EDG. At times, a fuel oil tank is removed from service and drained for cleaning. In this case, the Technical Specification requires the corresponding EDG to be declared Inoperable.

However, with one fuel oil tank remaining available, the EDG will start and has enough fuel to run for over 3 days with no operator action required (Note: the mission time is 7 days). In addition, plans are in place in emergency scenarios for the delivery of fuel oil.

Another example for the same configuration, each fuel oil storage tank has a separate fuel oil transfer pump. At one time, both fuel oil transfer pumps were inoperable to support troubleshooting activities. The EDG day tanks were available and would support EDG start and contain sufficient fuel to run for a few hours. During the troubleshooting activities, work was performed in accordance with a procedure, an operator was stationed locally for restoration, and the restoration steps were non-complicated.

For both examples, the EDG will perform its safety function for an ample time following a loss of offsite power with no immediate operator action; does this time have to be counted as unavailable hours for the EDG?

Response Yes. No credit may be taken for operator actions for planned or unplanned unavailable hours other than testing as discussed on page 26 of NEI 99-02.

ID 165

Posting Date 05/02/2000

Question NEI 99-02 does not adequately address how to evaluate unplanned unavailable hours for situations where support systems are not immediately required but are required for long term operation. For example: One of our plants has a situation where a breaker for some DG support systems, specifically, fuel transfer to the DG day tank (4 hour capacity), and room cooling (during the winter) was found to be inoperable. For this situation, the DG would have started and performed it's intended function for a length of time (probably 4 hours). Also, control room alarms and/or local log recording would have noted the deficient condition, and administrative controls would have provided for restoration of the system without losing the Diesel Generator safety function. Engineering analysis can determine how long the DG would operate compared to the expected response by the plant for restoration of the support systems. However, NEI 99-02 does not address alarms and operator actions for this type of situation. For this type of situation, may credit be taken for analysis involving alarms and actions?

Response No. No credit may be taken for operator actions for planned or unplanned unavailable hours other than testing as discussed on page 26 of NEI 99-02.

ID 154

Posting Date 04/01/2000

Question When accounting for Fault Exposure Hours during a current quarter it is discovered that the Fault Exposure Hours (T/2) would also have been accrued in the previous quarter (overlapped with previous quarter). Does the previously submitted quarterly data need to be revised to reflect the Fault Exposure Hours that were assumed to occur in the previous quarter?

Response The fault exposure unavailable hours associated with a component failure may include unavailable hours covering several reporting periods (e.g., several quarters). In this case, the fault exposure unavailable hours should be assigned to the appropriate reporting periods. For example, if a failure is discovered on the 10th day of a quarter and the estimated number of unavailable hours is 300 hours, then 240 hours should be counted for the current quarter and 60 unavailable hours should be counted for the previous quarter. Note: This will require an update of the previous quarters data.

ID 152

Posting Date 04/01/2000

Question Support systems (service water, component cooling, electrical) at our plant for HPSI and RHR each contain 100% redundant equipment. On a periodic basis, these systems and equipment are realigned to swap components, flow paths or alignments as part of normal operation. The evolutions are frequently performed, by procedure with the operator in close contact with the control room and dedicated to the evolutions. The evolutions can be stopped, backed out and the systems restored to the original configuration at any point of the procedure. The ability of safety systems HPSI and RHR to actuate and start is not impaired by these evolutions. Restoration actions are virtually certain to be successful. Does the time to perform these evolutions on a support system need to be counted as unavailability for HPSI and RHR?

Response No. As described in the question, the ability of safety systems HPSI and RHR to actuate and start is not impaired by these evolutions. There are no unavailable hours.

ID 147

Posting Date 04/01/2000

Question NEI 99-02 states that Planned Unavailable Hours include testing, unless the configuration is automatically overridden by a valid starting signal or the function can be promptly restored, either by an operator in the control room or by a dedicated operator stationed locally for that purpose. If credit is taken for an operator in the control room, must it be a "dedicated" control room operator or can prompt operator actions be conducted by the same operator who would then perform the configuration restoration?

Response Yes, a dedicated operator is required. The intent is that the configuration be restored promptly by an operator independent of other control room operator immediate actions that may also be required. Therefore, an individual must be "dedicated." Normal control room staffing may satisfy this purpose depending on work assignments during the configuration. However, in all cases the staffing consideration must be made in advance and purposely include the dedicated immediate response for the testing configuration.

ID 88

Posting Date 02/15/2000

Question If a failure occurs and the time of discovery is known and the time of failure can be estimated with an appropriate level of investigation, analysis and engineering judgment, should the fault exposure unavailability hours be determined using this information or does "Only the time of the failures discovery is known with certainty," imply that the time of failure must be known with certainty (and can not be determined through analysis, reviews, or engineering estimates)?

Response The intent of the use of the term "with certainty" is to ensure an appropriate analysis and review is completed to determine the time of failure. The use of component failure analysis, circuit analysis,engineering judgement, or event investigations are acceptable provided these approaches are documented in your corrective action program and reviewed bymanagement.

ID 86

Posting Date 02/15/2000

Question In NEI 99-02, it states, The purpose of the safety system unavailability indicator is to monitor the readiness of important safety systems to perform their safety functions in response to off-normal events or accidents. NEI 99-02 also states, Hours required are the number of hours a monitored safety system is required to be available to satisfactorily perform its intended safety function. Does the phrase "perform their safety functions in response to off-normal events or accidents refer only to credited accidents in the UFSAR, or is it intended to include events such as an Appendix R event?

Response Yes. Off-normal events or accidents are as specified in your design and licensing bases, therefore, UFSAR and Appendix R events should be considered.

ID 74

Posting Date 02/15/2000

Question NEI 99-02, Section 2.2, Mitigating Systems Cornerstone, Safety System Unavailability, Clarifying Notes, under Hours Train Required:

For all other systems (e.g Aux Feed and HPSI), this value is estimated by the number of critical hours during the reporting period, because these systems are usually required to be in service only while the reactor is critical and for short periods during startup or shutdown. As I read this statement, we are to estimate by counting critical hours and are not required to count time in lower modes, even if that equipment is required to be operable per Tech Specs in the lower modes, correct?

Response The default value in the denominator can be used to simplify data collection. However, the numerator must include all unavailable hours that the train is required, regardless of the default value.

ID 73

Posting Date 02/15/2000

Question NEI 99-02, Section 2.2, Mitigating Systems Cornerstone, Safety System Unavailability, Clarifying Notes, under Planned Unavailable Hours:

There is a discussion of one cause of planned unavailable hours as testing, unless the testing configuration is automatically overridden by a valid starting signal or the function can be promptly restored, either by an operator in the control room or by a dedicated operator stationed locally for that purpose. 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. Credit for a dedicated operator can be taken only if (s)he is positioned at the proper location throughout the duration of the test for the purpose of restoration of the train should a valid demand occur.

A clarification question is: Can we credit an operator in the main control room if the operator is not positioned directly over the piece of equipment, but is in close vicinity to it and can respond to start the equipment?

Another clarification question is: As stated above, restoration actions must be uncomplicated --If a field operator

with communication to the Main Control Room is available to restore a piece of equipment that has been tagged Out of Service (OOS), can we credit the action of lifting the OOS as "uncomplicated", or is it to be regarded as more complex since it will involve more than a single action?

Response The answer to the first question is yes.The second question is very situation specific, but most likely the answer would be no, because clearing tags for OOS equipment would be complicated and not meet the restoration criteria.

ID 70

Posting Date 02/15/2000

Question Is there guidance as to how many hours in advance the activities must be planned to be considered "Planned Unavailable hours"? If not, do we establish our own time limit?

Response The footnote was removed because it did not apply to this indicator. The guidance for this indicator defines planned unavailable hours and unplanned unavailable hours. The intent is that if equipment is electively removed from service it is considered planned maintenance, independent of the number of hours it was planned ahead.

ID 19

Posting Date 02/15/2000

Question If a maintenance activity goes beyond the originally scheduled time frame due to delays in work or additional work items are found during the course of a planned system maintenance outage, are the additional unavailable hours considered planned?

Response Yes, unless you detect a new failed component that prevented the train from performing its intended safety function.

ID 14

Posting Date 02/15/2000

Question In the guidance for planned unavailable hours it says 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. Is it acceptable to have a procedure action call for restoration of the transmitter if directed by the control room (when normal transmitter restoration is a skill of craft evolution), or would detailed procedure steps be required (i.e., lift test leads, land wire, etc.). Also, is it intended that for an activity to be uncomplicated, it must involve a single action, or is the definition of uncomplicated dependent on the specific circumstances (e.g., the amount of time available for restoration, the difficulty of the actions regardless of number, etc.).

Response As stated in the guideline, credit is allowed for restoration actions that are virtually certain to be successful (i.e., probability nearly equal to 1) during accident conditions. Under stressful, chaotic conditions, otherwise simple, multiple actions may not be accomplished with the virtual certainty called for by the guidance (e.g., lift test leads, land wires).

ID 87

Posting Date 01/07/2000

Question Should unavailability and fault exposure hours be counted for items that do not affect the automatic start and load of the Emergency Diesel Generators (EDG), but do affect the ability to manually start them?

Response This is a plant specific question which must be answered based on safety function of the manual start feature. Make a best faith effort (which could include discussion with your resident) to determine the answer and document your decision.

ID 71

Posting Date 01/07/2000

Question In regards to the NRC PWR Residual Heat Removal (RHR) Performance Indicator, at our plant the Low Pressure Safety Injection (LPSI) pumps do not contribute to the post accident recirculation function (they receive an auto shutdown signal on a Recirculation signal). Given that, if a LPSI pump or header is taken OOS for maintenance while the unit is at power, should unavailable hours be counted against the train since its only function (normal S/D cooling) is not needed in this mode and there is an extended period of time before the plant would be in condition to begin normal S/D cooling?

Response If your tech specs do not require your LPSI pumps while at power, then the hours do not count as unavailable for the PI. Make a best faith effort to provide the data and state your assumptions in the comment field.

ID 21

Posting Date 11/11/1999

Question If a load run failure occurs during the time that the EDG is not required to be operable by Tech Specs, is this counted as fault exposure if corrective measures are implemented prior to conditions requiring that same EDG to be made operable? This happens in shutdown conditions whereby one EDG at a time could be electively removed from service.

Response Fault exposure hours do not need to be counted when an EDG is not required to be operable.

When a failure occurs on equipment that is not required to be operable, if the most recent successful test and recovery/correction of the failure are all made inside the window where the equipment is not required available, no faulted hours are recorded.

If the most recent successful test occurred when the EDG was required to be operable and discovery/correction of the failure are made during a period when the EDG is not required to be operable, faulted hours are recorded on equipment for that portion of the time that the EDG was required to be operable. No fault exposure hours are recorded for times when the EDG is not required.

ID 20

Posting Date 11/11/1999

Question Do you have to count unavailability time for when test return lines used for surveillance testing are out of service? NEI 99-02 states, This capability is monitored for the injection and recirculation phases of the high pressure system response to an accident condition. Does the term "recirculation" refer to the HPCI system taking water from its suppression pool suction, injecting that water into the vessel, and having that water leak from the vessel through the break back to the suppression pool (as opposed to taking the water from the CST and injecting it)? Or is it intended to refer to the system alignment where the test-return valve is open and HPCI is taking water from the CST or suppression pool and putting the water back to the CST or suppression pool without injecting it into the vessel?

Response The test-return line is not required for availability of the HPCI/RCIC system. The test return line can be out of service without counting HPCI/RCIC as unavailable.

The term "recirculation" in this context refers to the recirculation of the water from the suppression pool, into the vessel through the injection line, and back to the suppression pool through the leak.

ID 18

Posting Date 11/11/1999

Question The Nuclear Service Water (NSW) assured suction supply to Auxiliary Feedwater (AFW) was recently determined to be sufficiently occluded with MIC build-up to be unable to fulfill its function under certain accident scenarios. During a postulated seismic event concurrent with a loss of offsite power (LOOP), the normal seismic condensate suction sources would be assumed to be unavailable. Because of the pressure drop associated with the MIC occlusion, it would be possible to induce a negative pressure at the AFW suction, potentially drawing air into the suction from the postulated secondary side line break.

The MIC build-up has since been cleared, and flow testing of the NSW supply is now performed. The NSW piping had not been flow tested as part of the plants GL 89-13 program until after discovery of this condition, so the fault exposure time of this condition is indeterminate. Under the NEI 99-02 guidelines, how should the fault exposure hours for this condition be addressed?

Response First, an assessment needs to be performed to determine the impact of the MIC build-up on capability of the AFW system to perform its safety functions under all design basis conditions. If the MIC buildup is severe enough to prevent fulfillment of the AFW safety function under design basis accident conditions, then the following guidance would apply.

The absence of periodic inspection or testing of portions of a system that is relied upon during design basis accident conditions, would be considered a design deficiency. For design deficiencies that occurred in a previous reporting period, fault exposure hours are not reported. However, unplanned unavailable hours are counted from the time of discovery. The indicator report is annotated to identify the presence of the design deficiency, and the inspection process will assess the significance of the deficiency.

ID 17

Posting Date 11/11/1999

Question Can both RHR Shutdown Cooling subsystems be removed from service without incurring Planned or Unplanned Unavailable Hours provided an alternate method of decay heat removal is verified to be available for each RHR Shutdown Cooling subsystem required to be Operable for the Mitigating Systems / Safety Systems Performance Indicator?

Response Approved alternate methods for decay heat removal during shutdown cooling may be considered Installed Spares provided the components are not required in the design basis safety analysis for the system to perform its safety function. NEI 99-02 provides additional guidance on Installed Spares and Redundant Maintenance Trains. Unavailability hours for installed spares are to be counted if the installed spare becomes unavailable while serving as a replacement and the hours the installed spare is relied upon will also be included in the calculations required hours.

ID 15

Posting Date 11/11/1999

Question The Safety System Unavailability Performance Indicator requests data be provided for the following functions: 1) high pressure injection systems, 2) heat removal systems, 3) residual heat removal systems, and 4) emergency AC power systems. The monitored functions for the RHR system are:

Removal of heat from the suppression, and

Removal of decay heat from the reactor core during a normal unit shutdown (e.g. for refueling or servicing).

Our plant does not have an RHR system. The identified functions are performed by the Low-Pressure Coolant Injection/Containment Cooling Service Water system and the Shutdown Cooling system, What should be reported for this indicator?

Response It is acknowledged that unique plant configurations can affect performance indicator reporting. The circumstances of each occurrence should be identified as early as possible to the NRC so that a determination can be made as to whether alternate data reporting can be used in place of the data called for in the guidance.

ID 13

Posting Date 11/11/1999

Question Is it intended that the operator used in the definition of planned unavailability be a licensed operator or can the restoration actions be accomplished by other qualified plant personnel (e.g., I&C technician)

Response Qualified plant personnel, provided there is a means of communication with the Control Room, can perform the restoration actions.

ID 12

Posting Date 11/11/1999

Question Was it intended or anticipated when developing the guidance that SSCs could be considered operable, yet unavailable? Our plant has performed an Operability Determination that justifies maintaining the SI system operable when an SI flow transmitter is out of service for calibration (Restoration is uncomplicated and can be completed well before the transmitter function is needed). However, under NEI 99-02 guidance the out of service time would be counted under planned unavailability.

Response It is possible for an SSC to be considered operable yet unavailable per guidance in NEI 99-02. The purpose of the safety system unavailability indicator is to monitor the readiness of important safety systems to perform their safety functions in response to off-normal events or accidents. System unavailability due to testing is included in this indicator except when the testing configuration is automatically overridden or the function can be immediately restored. NEI 99-02 provides further guidance. The specifics of your situation should be assessed against this guidance to determine if the calibration time is counted.

ID 11

Posting Date 11/11/1999

Question How do you report Fault Exposure unavailability hours when ongoing failure analysis or root cause analysis may identify a specific time of occurrence for the failure? Do you report the unavailability time and fault exposure hours immediately upon discovery or can you report unavailability immediately and defer reporting potential fault exposure hours until completion of the failure analysis.

Response If the time of failure is not known with certainty, then the fault exposure hours should be reported as one half the time since the last successful test or operation that proved the system was capable of performing its safety function. The unavailability hours can be amended in a future report if further analysis identifies the time of failure or determines that the affected train would have been capable of performing its safety function during an operational event.

Mitigating Systems

MS02 High Pressure Injection System Unavailability

ID 403

Posting Date 11/17/2005

Question Millstone Unit 3 is a Westinghouse 4 loop plant. Per the definitions in NEI 99-02 Rev. 3 (Page 55 lines 29-39), the HPSI train is considered a 4-train system based on the number of flow paths. Two trains are part of the charging system (high head safety injection) and two are part of the SIH system (intermediate head safety injection).

For Millstone unit 3 the SIH system is a component of the Emergency Core Cooling System (ECCS) and is therefore credited for post-LOCA event mitigation. The SIH system supports initial injection from the Refueling Water Storage Tank (RWST) to the Reactor Coolant System (RCS) cold legs during the injection phase of the event. Within approximately 1 hour, the SIH suction is realigned to the RSS system for cold-leg recirculation, the first phase of post-accident recirculation. The RSS pumps take suction from the containment sump upon depletion of the RWST, and discharge to the suction of the charging pumps and the SIH pumps. RSS is the only system designed to take suction from the containment sump and provide suction boost during the post-accident recirculation phase, therefore it is required for all post-accident recirculation conditions that the SIH and charging systems support. The SIH system also provides hot leg recirculation during the post-LOCA recirculation phase for boron precipitation control in the event of a cold leg break. Realignment to support boron precipitation control is accomplished by realigning the SIH discharge path at approximately nine hours after event initiation. The suction path remains aligned to RSS for the duration that post-accident recirculation is required. The RSS system is monitored under the RHR function. This ECCS subsystem is cross-connected so any RSS pump can supply flow to all the charging and SIH flow paths.

In November 2004 Millstone concluded that a previously identified oil leak on the A SIH pump could have impacted the long term availability of that pump during the period 10/14 to 11/04/04. Based on the observed leak rate, it was calculated that the pump bearing would lose lubrication after approximately 7 days of operation causing the pump to seize. Further review identified that the B SIH pump was similarly impacted by an oil leak from 8/2002 to 4/2003 and would lose lubrication after approximately 15 days of operation causing the pump to seize. The SIH pump would have operated during the injection phase and for an extended period during the recirculation phase. A review of Millstone Unit 3 (MP3) licensing basis documents and relevant regulatory documents did not identify a post accident mission time for ECCS subsystems

A formal engineering evaluation was prepared to support the assessment of historical operability/availability. This evaluation determined that after 6 days the RSS pump alone could provide enough flow through the SIH piping and components (with no change of system alignment) to meet the hot leg recirculation flow requirements with a postulated seized SIH pump. Thus, it was determined that the mission time for the SIH pumps is 6 days. Based on this evaluation, it was determined that the ECCS system was Operable and that the HPSI safety function was available per NEI 99-02.

In summary: Millstone SIH pumps had oil leaks that may have caused the pumps to fail at 7 days or more. The SIH mission time is 6 days. At the time of postulated failure, during the post-accident recirculation phase, the HPSI safety function will have been satisfied and RSS would be in its required lineup providing its safety function. Therefore, no unavailability hours should be counted for the HPSI or RHR performance indicators. Is Millstones interpretation of this situation correct?

Response Appeal Process Decision - Not to be used for future reference or incorporation into NEI 99-02.

The fault exposure hours need not be counted in this case. The acceptability of engineering analysis is addressed directly in the guidance as an additional fault exposure consideration. The Millstone approach is consistent with that guidance. The NEI 99-02 guidance on credit for alternate systems is an appropriate consideration in this case, but open to more judgement. The Millstone interpretation is satisfactory based predominately on the observations that RSS is also a monitored system and the NEI 99-02 guidance with respect to cascading unavailability.

ID 400

Posting Date 07/21/2005

Question **NEI 99-02 Guidance needing interpretation (include page and line citation):**

NEI 99-02 revision 2, page 33, lines 8 through 23

8 Equipment
Unavailability due to Design Deficiency

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Equipment failures due to design deficiency will be treated in the following manner:

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Failures that are capable of being discovered during surveillance tests: These failures should be

13 evaluated
for inclusion in the equipment unavailability indicators. Examples of this type are

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failures due to material deficiencies, subcomponent sizing/settings, lubrication deficiencies, and

15
environmental degradation problems.

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Failures that are not capable of being discovered during normal surveillance tests: These failures

18 are
usually of longer fault exposure time. These failures are amenable to evaluation through the

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NRCs Significance Determination Process and are excluded from the unavailability indicators.

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Examples of this type are failures due to pressure locking/thermal binding of isolation valves or

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inadequate component sizing/settings under accident conditions (not under normal test

22
conditions). While not included in the calculation of the unavailability indicators, these failures

23 and
the associated hours should be reported in the comment field of the PI data submittal.

Event or circumstances requiring guidance interpretation:

In July 2004 Palo Verde Engineering identified a concern that an air pocket existed in the safety injection recirculation suction piping between the containment sump inboard and first check valve downstream of the outboard isolation valves. This section of safety injection suction piping is used following a Loss of Coolant Accident (LOCA) when the system shifts to recirculation mode. Engineering determined that the air in this unfilled section of suction piping could potentially be drawn into the High Pressure Safety Injection (HPSI) pump and the Containment Spray (CS) pumps when the system shifted to recirculation mode, following a Recirculation Action Signal (RAS), and potential affect the operability of both the HPSI and CS system.

During a LOCA, when large quantities of water escape the reactor coolant system, water is injected into the core from the Refueling Water Tank (RWT). When the water level in the RWT gets to an identified low point, a RAS allows reactor cooling to continue by recirculating the water that has collected in the containment sump.

Palo Verde took the initial corrective action of providing a step for operators to open the inboard valve in the event of a loss of coolant accident. This would draw water from the sump and fill the line between the inboard and outboard valves and displace the air in the pipe. Engineering believed that the additional approximately 10 cubic feet of air between outboard isolation valve and the downstream check valve would not prevent water flow through the HPSI and CS systems.

To mitigate the need for operator action and place the units in a safer condition, the sumps and the entire length of pipe between the sump and the safety injection pumps were filled to remove any air pockets. Palo Verde units 1, 2, and 3 are currently maintained in this condition while Engineering completes its analysis and determines what permanent modifications, if any, are required.

As part of the Palo Verde incident investigation, a very comprehensive evaluation was performed to determine how the system would have operated if called upon and determine the significance of the design configuration deficiency. The evaluation included a scale model test and a full scale test. The tests were performed in two distinct steps. First, the scale model test was performed to demonstrate that the behavior of the air in the piping could be

determined. This test was performed at Fauske and Associates. Once the behavior of the transient was determined and verified through sensitivity testing, the output of the scale model test was scaled up and used as an input to the full scale testing performed at Wyle Laboratories in December 2004. The full scale test was performed to determine the impact of the flow of water and air on the performance of the actual pumps used in the plant.

Based the tests and analyses, Palo Verde concluded that under certain accident scenarios, the HPSI system may not have been able to deliver sufficient flow to perform the required system safety function and therefore was considered inoperable from initial plant startup. However, the CS system was able to perform the required system safety functions and was considered operable. The incident investigation determined that several causes contributed to the condition which included:

A breakdown in communicating the design requirement to the end user in that the documents used as references for writing the operating and test procedures did not include the requirement to maintain the sump line in a filled condition.

The Palo Verde Technical Specifications only required verifying full the discharge piping and did not mention the suction piping.

The design of the system did not facilitate filling this section of piping.

Because the engineering evaluation had not yet been completed, Palo Verde included the following notes in the third quarter 2004 NRC performance indicator submittal for the HPSI and Residual Heat Removal (RHR) systems respectively:

Engineering evaluation of HPSI unavailability due to air in containment recirculation sump piping is pending.

Engineering evaluation of RHR unavailability due to air in containment recirculation sump piping is pending.

In the fourth quarter 2004 NRC performance indicator submittal, after the engineering evaluation results were known, Palo Verde included the following notes with the HPSI and RHR system unavailability data:

An engineering evaluation of HPSI unavailability due to air in the containment recirculation sump piping determined that the HPSI system may not have been able to perform its safety function in response to certain accident scenarios. The deficiency was not capable of being discovered during normal surveillance testing and as such is a design deficiency. The design deficiency has existed since initial plant operation. The condition is being evaluated under the NRC's Significance Determination Process and the associated fault exposure hours are not included in the calculation of the unavailability indicator in accordance with the provisions of NEI 99-02, "Equipment Unavailability due to Design Deficiency."

An engineering evaluation of RHR unavailability due to air in the containment recirculation sump piping determined that the RHR system was able to perform its intended safety function. No design deficiency existed. As such, no fault exposure hours are included in the calculation of the unavailability indicator.

No fault exposure hours were reported in the data that affected the performance indicator for the HPSI system because, as indicated in the submitted note, Palo Verde considered this a design deficiency that existed since initial plant startup. The condition was not capable of being discovered during normal surveillance testing because Palo Verde intentionally operated with the containment suction line unfilled and the Palo Verde Technical Specifications only required that the HPSI pump discharge piping be verified full. There are leak rate surveillance tests and valve stroke surveillance tests performed on the inboard containment sump suction valve. However, since Palo Verde intentionally operated the system with the suction piping unfilled and the Palo Verde Technical Specifications had no requirement to verify that the suction piping was full, the leak rate and valve stroke surveillance testing would only verify that the inboard containment sump valve seated tightly. The testing results would not discover that the HPSI system was inoperable as a result of the containment sump suction piping being left in an unfilled condition.

While Palo Verde was conducting the incident investigation and engineering evaluation, the NRC performed a special inspection in response to the discovered design configuration deficiency. The NRC characterized the condition as an apparent violation of 10 CFR Part 50, Appendix B, Criterion III, Design Control. The finding was further characterized as more than minor with potential safety significance (i.e. greater than green) based on a Significance Determination Process, Phase 3 analysis because it was associated with the equipment performance attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events.

The change in core damage frequency value based on assumptions from the NRC SPAR models was 2.5e-5 (which equates to a yellow finding). The change in core damage frequency value based on assumptions using Palo Verdes PRA was 7.0e-6 (which equates to a white finding.)

Should fault exposure hours be included in the performance indicator calculation for HPSI?

Potentially relevant existing FAQ numbers: 316 and 348

Response No. The condition existed since initial startup and the failure was not capable of being discovered during normal surveillance testing. A statement to that effect should be reported in the comment field.

ID 390

Posting Date 05/19/2005

Question As discussed in NEI 99-02 (Revision 2), licensees reduce the likelihood of reactor accidents by maintaining the availability and reliability of mitigating systems systems that mitigate the effects of initiating events to prevent core damage. The Harris Nuclear Plant (HNP) is actively pursuing measures to reduce mitigating system unavailability, such as those discussed below pertaining to High Head Safety Injection (HHSI) unavailability.

At the Harris plant, the Essential Services Chilled Water (ESCW) system is a support system (room cooling) for the HHSI system. The HHSI system consists of three centrifugal, high-head pumps, each housed in its own room. HNP Engineering recently analyzed the effect of a loss of ESCW on HHSI availability by performing a room

heatup calculation. This analysis showed that a train of HHSI can be maintained available even without the normal room cooling support system (ESCW) for a period greater than the PRA model success criteria (24 hours) through the use of a substitute cooling source powered by a non class 1E electric power source as allowed for in NEI 99-02, Page 37, Lines 27-35.

It is important to note that: 1) a HHSI train utilizing the substitute cooling source will be considered Inoperable, 2) only one HHSI train at a time will utilize a substitute cooling source, and 3) the length of time that HHSI is required following a design basis accident is not specified in the FSAR.

Since HHSI will remain available throughout the 24 hour period specified in the PRA model success criteria with a substitute cooling source, the Harris plant considers it available when calculating the NRCs Safety System Unavailability performance indicator.

HNP and the resident inspector are not in agreement with respect to how to interpret the definition of unavailability (Page 23, Line 29). Specifically, in this instance, can a safety system train be considered available if it successfully meets its PRA model success criteria or must it satisfy its design basis requirements (long term cooling) to be considered available?

Response The answer to your question is as follows: A safety system train may be considered available if it is capable of meeting its design basis success criteria. In addition, support systems for the train must be capable of meeting their design basis criteria. In this case, the support system is the Essential Services Chilled Water (ESCW) system. The guidance provides an alternative if the normal support system is not available, as follows: "In some instances, unavailability of a monitored system that is caused by unavailability of a support system used for cooling need not be reported if cooling water from another source can be substituted" (NEI 99-02, Revision 2, page 37, lines 23-25). The use of a fan rather than a cooling water source in place of the normal cooling water source does not meet the limitations. In addition, credit is not given for portable equipment installed temporarily to maintain availability of monitored equipment.

ID 273

Posting Date 05/31/2001

Question **Appendix D: Ginna**

Page 62 of NEI 99-02, Rev 0, states in part:

"...the isolation valve(s) between the RHR system and the HPSI pump suction is the boundary of the HPSI system."

Ginna Stations system design has three MOVs meeting this definition: 857A and 857C (two valves in series from the A RHR train) and 857B from the B RHR train. Each RHR train is a 100% train. MOVs 857 A and 857C are in parallel with 857B. If Ginna Station was to have a fault exposure to one of these three valves, it would not prevent any of the three HPSI pumps from performing its function of taking a suction from the containment emergency sump. Rather, a fault exposure to one of these three valves would prevent its associated RHR train from supplying a suction from the containment emergency sump to any of the three HPSI pumps. Thus, the boundary between the RHR and HPSI systems needs to be adjusted for Ginna Station.

Response The down-stream side of the isolation valve(s) between the RHR system and the HPSI pump suction is the boundary of the HPSI system for Ginna Station. The isolation valve(s) themselves will be in the RHR system and be associated with their respective RHR train.

ID 225

Posting Date 10/31/2000

Question On page 49 of NEI 99-02, the monitored function of the BWR HPCI system is described as The ability of the monitored system to take suction from the condensate storage tank or [emphasis added] from the suppression pool and inject at rated pressure and flow into the reactor vessel. However, the CST only provides about 30 minutes of water and the safety analysis assumes HPCI availability for about 8 hrs. If the suction path from the CST is available but the path from the suppression pool is not, are unavailable hours counted for HPCI?

Response Yes. The intent of the indicator is to monitor the ability of a system to perform its safety function. In this case, the safety function requires the availability of the suction path from the suppression pool. (Editorial Note: The guidance in NEI 99-02 will be changed to eliminate the words from the condensate storage tank or, leaving only from the suppression pool..)

ID 223

Posting Date 10/31/2000

Question In NEI 99-02, under the Support System Unavailability header, it is identified that in some instances, unavailability of a monitored system that is caused by unavailability of a support system used for cooling need not be reported if cooling water from another source can be substituted. The rules further state that if both the monitored and support system pumps are powered by a class 1E electric power source, then a pump powered by a non- class 1E source may be substituted provided the redundancy requirements to accommodate single failure requirements for electric power and cooling water are met.

At our site, the HPCS pump room is cooled by a safety related unit cooler, HVR-UC5. This unit cooler has non-safety related/non-Class 1E powered Normal Service Water (NSW) supplied to it and a safety related/Class 1E Standby Service Water (SSW) supplied to it as a backup cooling source. The SSW system has four 50% capacity pumps, two per train. Both trains of SSW merge into a common header at the unit cooler. If we remove one train of SSW from service can NSW be credited as a substitute thus keeping HVR-UC5 and the HPCS pump available?

Response In this case, no substitution is required, since the HPCS system is still available. Removal of one 100% train of SSW from the unit cooler has no effect on the availability of HPCS since one 100% train of SSW is still available to service the HVR-UC5 unit cooler. The single failure criteria should only be applied to cases where there is substitution of the support system and in cases where the mitigating systems have installed spares or redundant trains.

ID 188

Posting Date 06/14/2000

Question Appendix D, Indian Point 3

Regarding the HPSI indicator, we have the following question. Our plant has a unique flow path for high head recirculation. If this flow path was found isolated by a manual valve, would fault exposure hours necessarily be counted, even if the main flow path was available?

Our plant has three trains of HPSI with three intermediate pressure pumps fed by separate safety related power supplies. Our three trains share common suction supplies. For the recirculation phase of an accident, two HPSI pumps are required in the short term if the event was a small break LOCA. For a large break LOCA, the HPSI pumps are not required until we transfer to hot leg recirculation, which is required to occur between 14 and 23.4 hours after the LOCA. During high head recirculation (hot or cold leg), the HPSI suction is supplied by the output of low head pumps. We have two internal SI Recirculation pumps located in the containment that provide the primary choice for low head recirculation and for supplying the suction of the HPSI pumps. The external RHR pumps provide a backup to the internal SI Recirculation pumps for both functions. Both sets of pumps deliver flow through the RHR HXs that can then be routed to a common header for the suction of the HPSI pumps.

In the case of a passive failure requiring the isolation of the flow path to the common HPSI suction piping, we have a unique design in that a separate flow path is installed to deliver a suction supply to just one of our three SI pumps (specifically, the 32 SI pump). This flowpath bypasses the RHR HXs and would deliver sump fluid directly from the RHR pump discharge to the suction of the 32 SI pump. The internal recirculation pumps can not support this flowpath, but they can still be run for containment heat removal via recirculation spray if required. This alternate low to high head flowpath does not fit into the typical "train" design common in the industry because it is not used in the event of any active failure, and it relies on powering pumps and valves from all 3 of our EDGs. Our system is also unique in that loss of the alternate flow path is not a failure that equates to the NEI guidance. It appears that the mispositioning of a valve in the designs of the NEI guidance would cause the loss of one of two trains used for high head injection considering either and active or passive failure.

The mispositioning of the valve was reported in LER 2000-001. The LER reported a bounding risk assessment since the IPE does not model the passive failure flow path to the HHSI pumps header. The risk assessment determined that the core damage frequency (CDF) would be approximately 3E-8 per year with a conditional CDF of approximately 7.5E-9 for a period of three months (approximate time of valve misposition). This is not risk significant.

Response The fault exposure hours do not have to be counted. Except as specifically stated in the indicator definition and reporting guidance, no attempt is made to monitor or give credit in the indicator results for the presence of other systems (or sets of components) that add diversity to the mitigation or prevention of accidents. The passive failure mitigation features described as supporting the high head recirculation function, while serving a system diversity function, are not included as part of the high head safety injection system components monitored for this indicator.

ID 176

Posting Date 05/02/2000

Question NEI 99-02 contains the guidance for Safety System Unavailability - Planned Unavailable Hours. A system is to be considered unavailable during testing unless specified criteria are met.

Monthly HPCI oil samples are taken to monitor the performance of the Turbine and the HPCI Steam Isolation Valve. While taking the oil samples on the HPCI turbine, the Aux. Oil Pump is running and the flow controller is taken to manual and set to minimum flow to prevent an over-speed condition if an initiation signal occurs while the Aux. Oil Pump is running. This monthly oil sample takes about 15 to 30 minutes per month. During this time, the system is declared inoperable and the appropriate Technical Specification actions are entered. If a HPCI initiation signal were received, HPCI will automatically start. The control room operator will manually, with the HPCI flow controller, raise HPCI turbine speed and establish injection flow at 5600 gpm as directed by procedure. This manual action is unlike the automatic response. A fully automatic response would control the transient turbine acceleration and ramp open the steam stop valve and control the response of the governor control valve such that 5600 gpm is achieved in 35 seconds or better.

The restoration actions are simple, can be completed by a control room operator, are contained in a procedure, and the HPCI function can be restored. The question is if credit for operator restoration can be taken in this case based on the system starting on an automatic signal, restoration actions are part of a normal response to the system start and contained in a procedure, and the operators are trained on this action? Can HPCI be considered available in this case? In general, must the SSC response be identical to a fully automatic initiation and how does this compare to or the function can be immediately restored.

Response The unavailable hours would count because the system response specifically relies on operator action which is not virtually certain to be successful (NEI99-02 page 26 line 38). The operator actions have the potential to overspeed the turbine.

Mitigating Systems

MS02, MS04 Mitigating Systems

ID 340

Posting Date 05/01/2003

Question **Appendix D: St. Lucie**

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 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 © 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 are 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.

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.

ID 284

Posting Date 09/12/2001

Question **Appendix D: San Onofre**

At our ocean plant we periodically recirculate the water in our intake structure causing the temperature to rise in order to control marine growth. Marine mollusks, if allowed to grow larger than ¾" in size, can clog the condenser and component cooling water heat exchangers. This process is carried out over a six hour period in which the temperature is raised slowly in order to encourage fish to move toward the fish elevator so they can be removed from the intake. Temperature is then reduced and tunnels reversed to start the actual heat treat. Actual time with warm water in the intake is less than half of the evolution. A dedicated operator is stationed for the evolution, and by procedure at any point, can back out and restore normal intake temperatures by pushing a single button to

reposition a single circulating water gate. The gate is large and may take several minutes to reposition and clear the intake of the warm water, but a single button with a dedicated operator, in close communication with the control room initiates the gate closure. During this evolution, one train of service water, a support system for HPSI and RHR, is aligned to the opposite unit intake and remains fully Operable in accordance with the Technical Specifications. The second train is aligned to participate in the heat treat, and while functional, has water beyond the temperature required to perform its design function. This design function of the support system is restored with normal intake temperatures by the dedicated operator realigning the gate with a single button if needed. Gate operation is tested before the start of the evolution and restoration actions are virtually certain. Does the time required to perform these evolutions on a support system need to be counted as unavailability for HPSI and RHR

Response No. The period of heat treatment will not be considered as "unavailable" for the HPSI and RHR systems because of the utilitys actions to limit the environmental impact of heat treatments. As described in the question, the ability of safety systems HPSI and RHR to actuate and start is not impaired by these evolutions There are no unavailable hours.

ID 280

Posting Date 07/12/2001

Question NEI 99-02, Rev. 0 states in the Definition and Scope section for PWR High Pressure Safety Injection Systems that: "Because the residual heat removal system has been added to the PWR scope, the isolation valve(s) between the RHR system and the HPSI pump suction is the boundary of the HPSI system. The RHR pumps used for piggyback operation are no longer in HPSI scope." It is further stated later in the same section that the function monitored for HPSI is: "the ability of a HPSI train to take a suction from the primary water source (typically, a borated water tank), or from the containment emergency sump, and inject into the reactor coolant system at rated flow and pressure." These two statements appear to conflict. For our plant design the RHR / HPSI piggyback mode is the only path available for HPSI to get water from the containment sump and inject it into the RCS. Therefore, we have been counting unavailability of the RHR system upstream of the isolation valves between the RHR system and the HPSI pump suction as unavailability for RHR and HPSI. This would include component unavailability for containment sump isolation valves, RHR heat exchangers and the isolation valves between the RHR and HPSI systems.
Should the RHR and HPSI systems be treated independently such that RHR system unavailability should not count against HPSI even though the RHR system is required for the HPSI system to fulfill the function of taking a suction from the containment sump? If so, should unavailability of the isolation valves between the RHR and HPSI pumps' suction be only counted against HPSI?

Response Because RHR and HPSI are monitored as separate systems with each having its own performance indicator, there is no need to cascade RHR system unavailability into HPSI. RHR system unavailability includes the system upstream of the RHR system to HPSI system isolation valves. Unavailability of the isolation valves between the RHR system and the HPSI pump suction are only counted against the HPSI system.

Mitigating Systems

MS03 Heat Removal System Unavailability

ID 393

Posting Date 05/19/2005

Question NEI 99-02, pg 33 states that fault exposure is not taken for failures due to a design deficiency that was not capable of being discovered during normal surveillance tests and that these failures are amenable to evaluation through the NRC Significance Determination Process. If a failure occurs due to a combination of historical procedural and physical design deficiencies, should the unavailable hours be counted as fault exposure hours?

A Unit 1 condensate storage tank (CST) low-level instrumentation surveillance test (ST) was in progress, which transfers suction from the CST to the Suppression Pool (SP), with the high-pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) systems in the standby mode. During the suction path swap-over, a hydraulic transient occurred which caused an unexpected RCIC low pump suction pressure turbine trip. RCIC was declared inoperable and unavailable. No HPCI alarms or trips were observed.

The cause of the RCIC failure was voids in the suction piping for both of the RCIC and HPCI systems due to a combination of physical and procedural design deficiencies. A portion of the RCIC pump suction piping and the HPCI SP suction check valve bonnet were not designed with a vent path and the HPCI fill and vent procedure did not make use of a vent on SP suction piping between the HPCI SP suction check valve and the HPCI outboard isolation suction valve.

The presence of air voids in the system could not have been identified during previous surveillance testing or discovered by other mechanisms. The air voids and the design and procedural deficiencies were not identified until troubleshooting and evaluation of the event. The potential for air voids to go unvented had existed since the Unit 1 initial plant startup in 1986. The CST low-level ST in progress at the time of the event involved HPCI components with no testing criteria that would have identified a RCIC problem. This ST had been performed on several occasions with no RCIC system transients or alarms. In addition, numerous HPCI and RCIC system pump valve and flow tests and system functional tests had been performed with no indication of voids or hydraulic perturbations that would have identified the design deficiency.

This was the first time that conditions were aligned such that the transient could occur. The trigger for the event was a pressure wave developed in the common HPCI/RCIC suction piping during HPCI valve stroking with sufficient magnitude to meet the RCIC low suction pressure trip point. Had the HPCI procedure fully utilized all available HPCI system vent paths or had the HPCI and RCIC system valves and piping been provided with physical vents and procedural guidance in the design, then the transient would not have occurred.

The NRC representative believes that the cause of the event included deficiencies beyond design deficiencies that exclude it from consideration as a design failure and therefore should be counted in the PI. The station disagrees with this interpretation and believes that the issue is being adequately assessed through SDP that all design deficiencies ultimately have a human error component, and that FAQs 316 and 348 support this position.

Response Yes, fault exposure hours should be taken. The written guidance in NEI 99-02 allows fault exposure hours to be excluded for design or construction deficiencies leading to failures that are not capable of being discovered during normal surveillance testing. While the guidance is silent on combinations of design and other deficiencies, in this situation, procedural inadequacies were a significant contributor to the inadequate system fill. Additionally, the guidance states that failures capable of being discovered during normal surveillance testing should be evaluated for inclusion. The RCIC system was discovered to be unavailable during the first performance of a routine surveillance test (on the HPCI system) following the inadequate system fill.

ID 392

Posting Date 05/19/2005

Question At 1730 on September 10, 2004, BVPS Unit 1 experienced an automatic start of the turbine driven auxiliary feedwater (TDAFW) pump due to the failure (open position) of the turbine steam supply B train trip valve. The steam supply configuration is a single steam supply line with a motor operated valve (MOV) that branches into two parallel supply lines, each of which contains a trip valve. The MOV is normally open and the opening of either trip valve will result in a start of the TDAFW pump. The crew attempted unsuccessfully to close the B trip valve from the control room. At 1732, the MOV was shut and direction given to the control room operator in the form of written instructions to open the MOV if the TDAFW pump was required for feeding the steam generators. The written instructions were provided on a Maintenance Rule Availability Restoration Procedure form that is approved by a Senior Reactor Operator. The TDAFW pump was declared Tech Spec inoperable, but maintained available because it could be promptly restored from the control room (i.e. open the MOV) by a qualified operator without

diagnosis or repair, consistent with the guidance in NEI 99-02, Revision 2. It was subsequently determined that the cause of the B valve opening was a failure of a card in the Solid State Protection System which only affected the B train valve. In this scenario, can credit be taken for manual operation action to maintain the TDAFW pump available?

Response Yes. The actions to recover from the equipment malfunction are uncomplicated, proceduralized, and accomplished from the control room by a qualified operator without the need for diagnosis or repair.

ID 359

Posting Date 02/19/2004

Question 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.
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 pumps control switch affected its availability.
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 pull-to-lock) and does not require diagnosis.
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 its 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 forSafety 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.
In this example, can the manual operator action be credited in place of the automatic pump start function for continued pump availability?

Response Yes. The actions described satisfy the criteria of NEI 99-02, Rev. 2 for considering the Auxiliary Feed Pump available.

ID 348

Posting Date 06/18/2003

Question Should the fault exposure time associated with a design deficiency that was revealed as a result of surveillance testing, but due to factors that are not a part of normal testing be included in the calculation for determining unavailability?

Background: During post maintenance testing of 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). Note - no actual failure occurred and it was initially determined that the pump would have met its mission time. An investigation revealed that a flow orifice in the recirculation line was partially plugged with corrosion products, most likely introduced when the pump and associated piping were drained for maintenance. The normal suction path for Aux. Feedwater when conducting surveillance testing is the condensate storage tank (CST). The alternate water supply is safety-related service water (lake).

A determination was later made that the orifices would likely plug from suspended material in the service water supply and render the trains incapable of performing their 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 NRCs Significance Determination Process if the failure was not capable of being discovered during normal surveillance test. The lack of the word normal in the first statement implies both conditions apply to this situation if a literal interpretation is used

Response No. Failures that are not capable of being discovered during normal surveillance tests are excluded from the unavailability indicators. During performance of the normal surveillance tests described above, CST water is used, and as such, performing the surveillance could not identify that the orifice would clog when lake water was used.

ID 313

Posting Date 07/02/2002

Question On March 25, 2000, excessive sealant was applied to the 11AFW pump turbine outboard bearing housing. Some sealant eventually broke off inside the housing, migrated to the bearing and resulted in a bearing failure on May 16, 2001, during an overspeed test. SDP Phase 3 assessment determined the failure had substantial safety significance (Yellow) based on the equipment function of removing decay heat and the length of time the excessive sealant was applied. On December 13, 2001, the NRC completed a supplemental inspection that reviewed evaluations and corrective actions. The supplemental inspection closed the violation associated with the AFW pump bearing failure. In accordance with NEI 99-02, Rev 1, the fault exposure time associated with the 11 AFW turbine bearing failure was estimated as one half the time since the last successful test that proved the system was capable of performing its safety function and T/2 fault exposure of 81.3 hours was reported in 1Q2001 and 1092.48 hours was reported in 2Q2001. The reported T/2 fault exposure resulted in an increase of the Safety System Unavailability, Heat Removal System (i.e., AFW) performance indicator value to 1.9% in 2Q2001.As of 1Q2002, the AFW performance indicator has not crossed the green-white threshold of >2.0% unavailability. The unit is currently in an extended refueling/steam generator replacement outage. The AFW performance indicator value will cross the green-white threshold in 2Q2002 as a consequence of the extended outage because critical hours are not accumulating during shutdown. The guidance in NEI 99-02, Rev 2, was modified to exclude T/2 fault exposure hours from the calculation of the safety system unavailability and to report the hours in the comment section of the NRC PI data file. NEI 99-02, Rev 2, was not in effect when the T/2 fault exposure hours associated with the pump failure was reported. NEI 99-02, Rev 1, was in effect and required T/2 fault exposure hours to be reported in the data section of the NRC PI data file. NEI 99-02, Rev 2, specifies that T/2 fault exposure hours may be reset, provided the following criteria are met: 1. Four quarters have elapsed since the green-white threshold was crossed, 2. The fault exposure hours in any single increment of unavailability are greater than or equal to 336 hours, 3. Corrective actions associated with the increment of unavailability to preclude recurrence of the condition have been completed by the licensee, and 4. Supplemental inspection activities by the NRC have been completed and any resulting open items related to the condition causing the fault exposure have been closed out in an inspection report. We are seeking an exception to fault exposure reset criterion Number 1 above, regarding crossing the green-white threshold. The T/2 fault exposure reported for 11 AFW in 1Q and 2Q 2001 did not result in immediately crossing the green-white threshold. The performance of the AFW system since the fault exposure was reported has kept the indicator from exceeding the green-white threshold for 3 quarters. However, an extended Unit 1 outage will result in the indicator crossing the green-white threshold. Meanwhile, the event that caused the indicator to increase close to the green-white threshold has been corrected. In this case, crossing the Unit 1 AFW PI green-white threshold will not provide an accurate indication regarding the performance of the Unit 1 AFW system over the past four quarters. A white AFW PI will, however, bring about greater attention to an old performance problem that has already been corrected. An exception would allow fault exposure hours associated with the 11 AFW pump turbine bearing failure to be reset without crossing the green-white threshold and without four quarters elapsing since the green-white threshold was crossed. Without this exception, the AFW performance indicator will cross the green-white threshold in 2Q2002.

Response While this FAQ requests an exemption from NEI 99-02 Rev 2, all four requirements to reset fault exposure hours will have been met as of the end of the second quarter of 2002.

Requirement 1 - Four quarters have elapsed since the green-white threshold was crossed. While the PI threshold was not exceeded, the inspection finding (for the same issue) green white threshold was crossed with a Yellow finding, which will have been posted for four quarters, commencing 3Q01 through 2Q02.

Requirement 2 - Fault exposure hours in any single increment of unavailability are greater than or equal to 336 hours.

Requirement 3 - Corrective actions associated with the increment of unavailability to preclude recurrence of the condition have been completed.

Requirement 4 - Supplemental inspection activities by the NRC have been completed and any resulting open items related to the condition causing the fault exposure have been closed out in an inspection report.

Based on this information, the fault exposure hours can be reset for the third quarter 2002 report, to be submitted by October 21, 2002.

ID 281

Posting Date 08/16/2001

Question **Appendix D: Davis Besse**

Davis-Besse has an independent motor-driven feedwater pump (MDFP) that is separate from the two trains of 100% capacity turbine-driven auxiliary feedwater pumps. The piping for the MDFP (when in the auxiliary feedwater mode) is separate from the auxiliary feedwater system up to the steam generator containment isolation valves. The MDFP is not part of the original plant design, as it was added in 1985 following our loss-of-feedwater event to provide "a diverse means of supplying auxiliary feedwater to the steam generators, thus improving the reliability and availability of the auxiliary feedwater system" (quote from the DB Updated Safety Analysis Report).

The resolution to FAQ 182 was that Palo Verde should count the unavailability hours for their startup feedwater pump. However, since the DB MDFP is manually initiated, DB has not been reporting unavailability hours for the MDFP due to the exception stated on page 69 of NEI 99-02 Revision 0.

The DB MDFP is non-safety related, non-seismic, and is not Class 1E powered or automatically connected to the emergency diesel generators.

The DB MDFP is required by the Technical Specifications to be operable in modes 1 - 3. However, the Tech Specs do not require the MDFP to be aligned in the auxiliary feedwater mode when below 40 percent power. (The MDFP is used in the main feedwater mode as a startup feedwater pump when less than 40% power).

The DB auxiliary feedwater system is designed to automatically feed only an intact steam generator in the event of a steam or feedwater line break. Manual action must be taken to isolate the MDFP from a faulted steam generator.

The MDFP is included in the plant PRA, and is classified as high risk-significant for Davis-Besse

Per the DB Tech Specs, the MDFP and both trains of turbine-driven auxiliary feedwater pumps are required in Modes 1-3. The MDFP does not fit the NEI definition of either an "installed spare" or a "redundant extra train" perNEI 99-02, Rev. 0, pages 30 - 31.

Should the Davis-Besse MDFP be reported as a third train of Auxiliary Feedwater, even though it is manually initiated?

(Note: this FAQ is similar to Appendix D questions for Palo Verde and Crystal River regarding the auxiliary feedwater system)

Response Based on the information provided, this pump should be considered a third train of auxiliary feedwater for NEI 99-02 monitoring purposes. See the Palo Verde Appendix D question.

ID 268

Posting Date 05/31/2001

Question **Appendix D: Ginna**

NEI 99-02 states (p 26) that Planned Unavailable Hours include "...testing, unless the test configuration is automatically overridden by a valid starting signal, or the function can be promptly restored either by an operator in the control room or by a dedicated operator stationed locally for that purpose." Also,(p 40) The control room operator must be "...an operator independent of other control room operator immediate actions that may also be required. Therefore, an individual must be dedicated." Ginna Stations Standby Aux Feedwater Pumps do not have an auto-start signal; they are required to be manually started by an operator within 10 minutes. Should this be counted as unavailable time

Response No. The PI should not count them since this is an NRC approved design.

ID 260

Posting Date 04/04/2001

Question The Nuclear Service Water (NSW) system provides assured suction supply to the Auxiliary Feedwater (AFW) system under certain accident scenarios. During a postulated seismic event concurrent with a loss of offsite power (LOOP), the normal non-safety related, non-seismic condensate suction sources are assumed to be unavailable.
Flow testing is performed under the plant's Generic Letter 89-13 program to assure adequate flow. The alignment used in this testing renders this flowpath unavailable to fulfill its assured supply function. However, the normal condensate source remains available.

Recently a reactor trip occurred during the performance of this testing. The testing was terminated, but due to resource limitations during event recovery, the normal operating alignment was not restored. Therefore, the assured AFW supply remained unavailable for an extended period. However, during the event, the AFW system started automatically on a valid autostart signal (2/4 lo-lo SG level in 1/4 SGs, loss of both main feedwater pumps) and continued to operate for a period of two days to maintain steam generator levels drawing suction from the normal condensate supply.

Previously, whenever the assured supply has been unavailable, whether for testing or other alignments, the entire AFW system has been deemed unavailable based on a hypothetical design basis event scenario. However, the real world event described above results in the dichotomy of calling a system unavailable because its assured supply is unavailable while it was in fact fulfilling its design basis function. Under the NEI 99-02 guidelines, how

should unavailability be addressed in conditions where the assured supply is unavailable with the normal supply available?

Response The purpose of the safety system unavailability indictor is to monitor the readiness of important safety systems to perform their safety functions in response to off-normal events or accidents. Since the assumed suction supply to the AFW system is credited for off-normal events or accidents, the unavailable time should be counted unless the system could have been promptly restored by a dedicated operator stationed for that purpose during the testing

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ID 206

Posting Date 09/21/2000

Question Appendix D, Crystal River Unit 3 (CR-3) regarding FAQ 182 resolution.

PART B

CR-3 has an independent motor driven pump and independent piping system for the Auxiliary Feedwater (AFW) System that is separate from the EF System. The AFW pump (FWP-7) and associated components are designed to provide an additional non-safety grade source of secondary cooling water to the steam generators should a loss of all main and EF occur. This reduces reliance on the High Pressure Injection/Power Operated Relief Valve (HPI/PORV) mode of long term cooling. This AFW source was added to CR-3 in 1988 in response to NRC concerns on the issue of EF reliability (Generic Issue 124).

Per the FSAR, "The AFW source is non-safety grade and is not Class 1E powered or electrically connected to the emergency diesel generators. As such, it is not relied upon during design basis events and is intended for use on an "as available" basis only. AFW performs no safety function and there is no impact on nuclear safety if it fails to operate..It is not environmentally qualified nor Appendix R protected...Although the AFW source is non-safety grade it is creditedby the NRC as a compensating feature in enhancing the reliability of secondary decay heat removal. Auxiliary feedwater may be used, as defense-in depth, during emergency situation when steam generator pressure has been reduced to the point where EFP-2 is no longer available or to avoid EFP-2 cyclic operation."

FWP-7 is powered by an independent, non-safety related, diesel. FWP-7 is a manually started pump and the associated control valves are manually controlled from the Main Control Room.

FWP-7 is not safety related.

FWP-7 is not required by ITS to be OPERABLE in any MODE.

FWP-7 cannot replace either EFP-2 or EFP-3 to meet two train EFW ITS requirements. CR-3 design and usage of FWP-7 does not fit the NEI definition of either an "installed spare" or a "redundant extra train" as given on pages 30 and 31 of NEI 99-02, Rev. 0.

FWP-7 is credited in the FSAR for providing defense-in depth and as an additional source non-safety grade source of secondary cooling water to steam generators.

Should this be reported as a third train of AFW?

Response No, since the pump has no operability requirements in the Technical Specifications.

ID 205

Posting Date 09/21/2000

Question Appendix D, Crystal River Unit 3 (CR-3) regarding FAQ 182 resolution.

PART A

CR-3 has two EF System pumps and associated piping systems that are credited for Design Basis Accidents of Loss of Main Feedwater, Main Feedwater Line Break, Main Steam Line Break, and Small Break LOCA. A design criterion for the EF System is that a maximum time limit of 60 seconds from initiation signal to full flow shall not be exceeded forautomatic initiation. Pumps EFP-2 (steam turbine driven) and EFP-3 (independent diesel driven) are auto-start pumps and are tested for the 60-second time criteria. EFP-3 was installed in 1999 to replace a third pump, the electric motor driven (EFP-1) pump, due to emergency diesel generator electrical loading concerns in certain accident scenarios.

Per FSAR Section 10.5.2, "MAR [modification approval record] 98-03-01-02 installed a diesel driven Emergency Feedwater Pump (EFP-3) to functionally replace the motor driven Emergency Feedwater Pump (EFP-1) as the "A" EF Train."

The motor driven pump does not receive an automatic start signal. The motor driven pump is interlocked with the diesel driven pump so that if the diesel driven pump is operating, EFP-1 will be tripped or its start inhibited. The motor driven pump is maintained for defense-in-depth. EFP-1 can be used to transfer water from the condenser hotwell into the steam generators during a seismic event, if long term cooling is necessary. EFP-1 can be used as a backup to EFP-2 to supply EFW to the steam generators for fires in the Main Control Room, Cable Spreading Room, and Control Complex HVAC Room.

CR-3 is reporting RROP safety system unavailability performance indicator data on the basis of two EF pumps and trains. CR-3 is not reporting on EFP-1. CR-3 design and usage of EFP-1 does not fit the NEI definition of

either an "installed spare" or a "redundant extra train" as given on pages 30 and 31 of NEI 99-02, Rev. 0.

EFP-1 is safety-related and tested. However, EFP-1 is not required to be OPERABLE in any MODE in accordance with the Improved Technical Specifications (ITS). EFP-1 cannot replace EFP-3 to meet two train EFW ITS requirements. EFP-1 is included in the PRA but is not a "risk significant" component. EFP-1 is credited in the FSAR as noted above for providing defense-in depth and maintained for potential use in certain seismic and Appendix R conditions.

Should this be reported as a third train of AFW?

Response No, since the pump has no operability requirements in the Technical Specifications.

ID 182

Posting Date 05/24/2000

Question APPENDIX D PALO VERDE

NEI 99-02, revision 0 states "Some plants have a startup feedwater pump that requires manual actuation. Startup feedwater pumps are not included in the scope of the AFW system for this indicator." Our plants have startup feedwater pumps that require manual actuation. They are not safety related, but they are credited in the safety analysis report as providing additional reliability/availability to the AFW system and are required by Technical Specifications to be operable in modes 1, 2 and 3. They are also included in the plant PRA and are classified as high risk significant. Should these pumps be treated as third train of auxiliary feedwater for NEI 99-02 monitoring purposes or does the startup feedwater pump exemption apply?

Response Based on the information provided, these particular SSCs should be considered a third train of auxiliary feedwater for NEI 99-02 monitoring purposes

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Mitigating Systems

MS04 Residual Heat Removal System Unavailability

ID 404

Posting Date 11/17/2005

Question **(Appendix D, Crystal River 3)**

The Crystal River Unit 3 (CR-3) Decay Heat Seawater System contains two Decay Heat Seawater Pumps (RWP-3A and RWP-3B). RWP-3A takes suction from the A Raw Water Pit; RWP-3B takes suction from the B Raw Water Pit. The pits are supplied with water from the Gulf of Mexico. The system provides cooling water to the tube side of the two heat exchangers removing heat from the Decay Heat Closed Cycle Cooling Water (DC) System and subsequently rejects it to the ultimate heat sink (the Gulf of Mexico) through the discharge canal.

A recently performed operability assessment of Decay Heat Seawater pump RWP-3B demonstrated that although the pump remains operable, it exhibits a degraded flush flow condition. A refurbishment activity to restore the flush water flow to full qualification is being planned to occur at power operation during the best available schedule opportunity. No concern exists that RWP-3B will not continue to perform its intended function for the period leading up to the CR-3 refueling outage scheduled to commence on October 29, 2005. Overhaul of RWP-3B on-line will eliminate the need to perform the overhaul activity during the refueling outage and reduce the risk of relying on an operable, but degraded, component to support mid-loop operations during the outage.

Improved Technical Specification (ITS) 3.7.10, Decay Heat Seawater System, requires that two Decay Heat Seawater System trains shall be OPERABLE. If one train is inoperable, Condition A allows operation to continue for 72 hours. It is estimated that the rebuild activity of RWP-3B will take approximately 5 days. Thus, to perform the refurbishment activity online, a one-time allowed outage time (AOT) extension of the ITS 3.7.10 Completion Time to 10 days is needed. Other systems affected by the extended AOT needed to refurbish RWP-3B require their AOT to also be extended to 10 days. However, no maintenance is being performed on those systems.

CR-3 submitted License Amendment Request (LAR) #289, Revision 0, to the NRC on January 13, 2005. LAR #289, Revision 0, requested a one-time change to the CR-3 Facility Operating License in accordance with 10 CFR 50.90 to increase the Improved Technical Specification (ITS) allowed outage time (AOT) (one time from 72 hours to 10 days) in order to perform on-line overhaul maintenance to Emergency Nuclear Services Seawater Pump RWP-3B. LAR #289 proposed a one-time change to Improved Technical Specifications (ITS) 3.5.2, Emergency Core Cooling Systems (ECCS) - Operating, 3.6.6, Reactor Building Spray and Containment Cooling Systems, 3.7.8, Decay Heat Closed Cycle Cooling Water System (DC) and 3.7.10, Decay Heat Seawater System.

CR-3 submitted LAR #289, Revision 1, to the NRC on June 9, 2005. LAR #289, Revision 1, was necessary to update the probabilistic safety assessment that supports the acceptability of the changes proposed in LAR #289. The specific plant condition is a change in the normal position of the Power Operated Relief Valve (PORV) Block Valve (RCV-11) to be closed. This has been required in order to isolate a Reactor Coolant System (RCS) to Reactor Building atmosphere leak (approximately 2.5 gallons per minute) which was discovered on March 3, 2005, following the quarterly stroke test of RCV-11. In accordance with the evaluation performed for Administrative Instruction AI-506, Operational Decision Making, CR-3 will be operating with the RCV-10/11 flow path closed during normal operations until Refueling Outage 14 scheduled for Fall 2005. RCV-11 will be opened during certain Emergency Operating Procedure/Abnormal Procedure (EOP/AP) events to allow usage of the PORV during these events.

Calculation P-05-0001, Revision 1, PSA Risk Assessment of RWP-3B Extended AOT, has been revised to evaluate the risk impacts of operating with the PORV (RCV-10) and Block Valve (RCV-11) in this configuration during the proposed extended AOT for refurbishing RWP-3B.

The NRC issued License Amendment No. 221 to the CR-3 Operating License on September 15, 2005. The amendment revises the Improved Technical Specifications (ITS) to revise the completion time for CR-3 ITS 3.5.2, 3.6.6 3.7.8 3.7.10, Condition A, Required Action A.1 from 72 hours to 10 days. The extension may only be invoked once and remains applicable until RWP-3B has been refurbished.

A. Results of a Quantitative Risk Assessment

The PSA risk associated with the activity to repair RWP-3B is reasonable to support a one time on-line AOT extension request for 10 days based on Incremental Conditional Core Damage Probability (ICCDP) and Incremental Conditional Large Early Release Probability (ICLERP). The evaluation assumes no other equipment beyond the evaluated systems will be removed from service if the risk is adversely impacted based on maintenance rule 10 CFR 50.65(a)(4) risk assessments, that will be performed before and during the activity by procedure. Additional compensatory actions are provided which can further reduce the risk when practical. Their use should be based on the specific plant configuration during the use of the extended AOT.

Based on the risk assessment of the extended AOT, the increase in risk warrants that compensatory actions should be implemented which can reduce the risk by lowing the likelihood of initiating events such as LOOP or fire, and by increasing the likelihood of successful mitigation by optimizing the plant configuration, ensuring availability of the operational equipment, and enhancing operator awareness.

The risk metric for this activity is estimated with a delta Core Damage Frequency (CDF) of 4.0E-07/yr based on internal events. This is below the RG 1.174 limit of 1E-06 and is considered to be a very small risk. The corresponding delta Large Early Release Frequency (LERF) is below 1E-09/yr and is also considered very low based on the RG 1.174 limit of 1E-07. The risk due to fire was estimated using a sensitivity assessment to get a bounding delta CDF of due to fires of 2.72E-06/yr. Specific compensatory actions are planned to manage and reduce this risk.

The ICCDP for the planned activity is 1.18E-06 and considers the plant configuration with RCV-11 closed. This risk is acceptable based on industry guidance with proper risk management practices. Planned compensatory actions are expected to reduce this risk. Also, the actual work activity is only scheduled to use half of the requested time, which will reduce these values proportionately. The ICCDP is greater than that generally accepted for permanent AOT changes per RG 1.177; however, it is well within acceptable limits for performing online maintenance within the scope of maintenance rule guidance and is reasonable for a one time AOT extension.

A sensitivity case was run to assess the impact of increasing the loss of offsite power frequency. Tripling the frequency did not significantly increase the risk. Additionally, there is some increased risk to performing this activity while shutdown in Mode 5, which will further reduce the total delta risk of performing this activity at power.

Based on the IPEEE, fire can be a significant contributor to risk, however as shown, the risk can be estimated to be in the small risk region as defined by RG 1.174. In order to minimize the potential impact, compensatory actions can be used to reduce the probability of a fire occurring and enhance fire detection and suppression in the more vulnerable areas.

B. Expected Improvement in Plant Performance as a Result of the Overhaul Activity:

RWP-3B is currently OPERABLE. The lack of flush water flow to the upper pump bearings has been evaluated in accordance with Generic Letter 91-18, and the degraded condition was found acceptable. Compensatory actions such as augmented surveillance testing to ensure no further degradation have been implemented, and no pump performance issues or further degradation have been found.

During the upcoming refueling outage, the A Safeguards Bus will be removed from service for normal maintenance activities. These activities will result in the B Safeguards Bus and associated equipment (including RWP-3B) being the only method to available to remove core decay heat. CR3 plant management has conservatively requested the pump be rebuilt prior to the outage in order to reduce shutdown risk by having a fully qualified pump available to provide the decay heat removal function.

C. Net Change in Risk as a Result of the Overhaul Activity.

The net change in risk during plant operation is described in Section A. The enhancement to the plant during the shutdown (refuel) condition cannot be quantified, as CR3 does not have a shutdown PSA, but the qualitative risk will be less due to the non-degraded pump providing the necessary cooling to the Decay Heat System during a condition where decay heat cooling will be required.

Response For this plant specific situation, planned overhaul hours for the maintenance on the emergency nuclear services seawater pump RWP 3B may be excluded from the computation of monitored system unavailabilities. 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.

ID 394

Posting Date 05/19/2005

Question This FAQ seeks approval to exclude the unavailability that will be incurred during planned maintenance of large check valves and electric motor operated gate and globe valves in the Low Pressure Injection (LPI) System. This work has traditionally been performed during refueling outages either when a train can be taken out of service without incurring unavailability or during defueled maintenance when neither train of LPI is required to be operable. With a goal of performing shorter outages, it is desired to perform this work during power operation shortly before the start of a refueling outage. Performing this work shortly before the refueling outage will ensure the equipment is operating properly prior to its use for normal decay heat removal. This schedule is also expected to have a significant savings on dose and contamination. Performing this maintenance immediately after the system has been used to cool the unit down results in a maximum level of contamination in this equipment (with Co-58 being a significant contributor). If this work is performed shortly before refueling, there will be approximately 18 months of decay before work is performed (Co-58 will be reduced by a factor of about 190).

Although overhaul exemption is allowed for "major" components and components such as pumps and heat exchangers are explicitly classified as being "major" components, there is no discussion of whether certain types of valves can be considered "major" components. While "valves" are often thought of as relatively simple components (and in many instances are), there are numerous valves that are fairly complex due to size, tight shutoff requirements, actuator setup, etc. It seems that these "more complex" valves could be classified as "major" components such that work involving a major overhaul of just these components could be classified as overhaul maintenance.

QUANTITATIVE RISK ASSESSMENT, EXPECTED IMPROVEMENT IN PLANT PERFORMANCE, AND NET CHANGE IN RISK AS A RESULT OF THE OVERHAUL ACTIVITY

Was there NRC approval through an NOED, Technical Specification change, or other means?

In anticipation of moving the maintenance from outage work to "innage" work, Oconee applied for, and has been granted, approved Tech Specs to extend the allowed outage time for a train of LPI from 3 days to 7 days.

Was there a quantitative risk-assessment of the overhaul activity?

The submittal for this revision was based on the NRC's Safety Evaluation of BWOG Topical Report BAW-2295, Revision 1, "Justification for the Extension of Allowed Outage Time for Low Pressure Injection and Reactor building Spray Systems", (TAC No. MA3807), dated 6/30/99. The BWOG Topical Report contained a quantitative risk assessment. Regulatory Guides (RG) 1.174 and RG 1.177 were used to assess the impact of the proposed change.

What is the expected improvement in plant performance, and net change in risk as a result of the extended outage time?

The calculated value of incremental conditional core damage probability (ICCDP) for the proposed change was 3.4E-07. The calculated value of incremental conditional large early release probability (ICLERP) for the proposed change was 4.4E-10. These values are considered small for a single TS Completion Time change when compared against the 5.0E-07 and 5.0E-08 RG 1.177 guideline values. The NRC SER found the ICCDP values acceptable due to the following compensatory measures that lower the risk impacts:

- Avoiding simultaneous outages of additional risk-significant components during the Completion Time of

the LPI and RBS system trains. These components whose simultaneous outages are to be avoided, in addition to current TS requirements, include both Auxiliary Feedwater System (EWF) trains, both High Pressure Injection (HPI) trains (for reasons other than inoperable due to the associated LPI train), all three reactor building cooling (RBCU) trains, and their power supplies.

- Defining specific criteria for scheduling only those preventive maintenance activities that can be completed within the 7 day Completion Time.
- Assuring that the frequency of entry into the Condition and the average maintenance duration per year remain within the assumed values in the Topical Report.
- Taking measures to assure that when maintaining the LPI and RBS trains, both are not made unavailable unless it is necessary.

Can we exclude the unavailability hours that will be incurred during planned maintenance of large check valves and electric motor operated gate and globe valves in the Low Pressure Injection (LPI) System?

Response No. For the purpose of excluding planned overhaul hours, valves are not considered major components.

ID 391

Posting Date 05/19/2005

Question The Safety System Unavailability Performance Indicator for BWR Residual Heat Removal (RHR) Systems monitors:

- the ability of the RHR system to remove heat from the suppression pool so that pool temperatures do not exceed plant design limits, and,
- the ability of the RHR system to remove decay heat from the reactor core during a normal unit shutdown (e.g., for refueling or servicing).

Perry Technical Specifications require an alternate means of decay heat removal (DHR) to be available when removing an RHR system from service. Technical Specifications do not restrict the options for an alternate decay heat removal system to specific systems or methods. The Bases of Technical Specifications for LCO 3.4.10, RHR Shutdown Cooling System - Shutdown, Required Action A.1 state, The required cooling capacity of the alternate method should be ensured by verifying (by calculation or demonstration) its capability to maintain or reduce temperature. Alternate methods that can be used include (but are not limited to) the Reactor Water Cleanup System. During the repair of Emergency Service Water (ESW) Pump B, an Off-Normal Instruction with an attachment for "RPV Feed And Bleed With ESW Not Available" was credited as an alternate decay heat removal method for the inoperable RHR system. The referenced procedure takes reactor water from the RHR system shutdown cooling flowpath and directs it to the main generator condenser which acts as the heat sink. The condensate and feedwater systems return the cooled water to the reactor. Reactor temperature is limited to 150 o F for this alternate DHR method. The heat removal capability of this method was demonstrated by calculation before being credited. Does the Perry reactor feed and bleed methodology described above constitute an "NRC approved alternate method of decay heat removal" as referenced in NEI 99-02 above?

Response No. NRC approval means a specific method or methods described in the technical specifications.

ID 380

Posting Date 03/17/2005

Question Appendix D

BFN 1 needs to remove blanks installed in spectacle flanges in RHR service water piping on the A and C trains to restore service water flow capability to the 1A & 1C RHR heat exchanger as part of BFN 1 restart test and system turnover. To remove these system boundary blanks, the service water to the related U2 and U3 RHR heat exchangers will have to be removed from service. The U2 and U3 RHR system each contain 2 100% capacity RHR headers each with two 50% capacity heat exchangers. The heat exchangers are paired as A & C in one header and B & D in the other. The U1 restoration work is planned such that during time the A RHR heat exchanger on U2 and U3 is out of service, the service water supply to the C heat exchangers will remain available. When the C RHR heat exchanger on U2 and U3 is out of service the service water to the A heat exchangers will remain available. The work to remove the blanks can easily be performed within the Tech Spec AOT of 30 days for an RHRSW Heat Exchanger. The work is planned to take approximately 34 hours per heat exchanger train. This potential out of service time would equate to approximately 5% of the available hours to the

green threshold for each unit. This FAQ seeks approval to exclude the unavailability on the U2 and U3 A & C trains of RHR due to support system unavailability during this planned Unit 1 restart activity.

Can a one time site specific exemption be granted to exclude from the ROP SSU RHR PI the planned unavailability on BFN U2 and U3 A & C trains that result from the BFN 1 RHR service water restoration activities?

Response Yes. The effect of the Browns Ferry Nuclear (BFN) Unit 1 Residual Heat Removal (RHR) service water restoration activities on Unit 2 and Unit 3 RHR system availability is a unique condition that had not been anticipated during the development of the PI guidance document. The unavailability of the Unit 2 and Unit 3 RHR system due to the Unit 1 restoration work does not truly reflect the performance of these systems. For this unique, one-time-only activity, the planned unavailability of the BFN Unit 2 and Unit 3 RHR system unavailability due to the BFN Unit 1 RHR service water restoration may be excluded from the RHR safety system unavailability PI.

ID 339

Posting Date 05/01/2003

Question **Appendix D: Sequoyah**

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 LCVs 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?

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.

ID 330

Posting Date 12/12/2002

Question **Appendix D - Millstone 2**

NEI 99-02 identifies the Residual Heat Removal (RHR) System as a system that is required to be in service at all times. In certain situations, monitoring the RHR System in accordance with the NEI 99-02 guidance for Millstone 2 results in the required hours for the RHR system that are less than the total hours for a given calendar quarter. This is a result of the containment spray system not being required by the technical specifications in mode 3 with RCS pressures less than 1750 psia.

NEI 99-02 requires the following two functions be monitored for Residual Heat Removal (RHR) performance indicator: (1) the ability to take a suction from containment sump, cool the fluid, and inject at low pressure into the RCS, and (2) the ability to remove decay heat from the reactor during normal unit shutdown for refueling or maintenance.

For the Millstone 2 and several other Combustion Engineering (CE) designed NSSS, Appendix D of NEI 99-02 provides clarification regarding how this performance indicator should be monitored. To monitor the first function, Appendix D recommends that the two containment spray pumps and associated coolers should be counted as two trains of RHR providing the post accident recirculation cooling. To monitor the second function, Appendix D recommends that the SDC system be counted as two trains of RHR. The first function is required by the plant technical specifications in modes 1 and 2 as well as in mode 3 with RCS pressures greater than 1750 psia. This second function is required by the technical specifications in modes 4, 5 and 6. As such, at Millstone 2, the RHR function is not being monitored while the plant is in mode 3 with RCS pressures less than 1750 psia. Therefore, if the plant is operated in mode 3 with RCS pressures less than 1750 psia for any given calendar quarter, the

required hours for the RHR function will be less than the total hours in that quarter. There are no specific restrictions as to how long the plant can be operated in Mode 3 with RCS pressure less than 1750 psia. Depending upon the nature of plant maintenance or repairs, the hours a plant is in this mode could be considerable.

From an accident analysis standpoint, following a main steam line break or loss of coolant accident inside containment, the RCS decay heat removal safety function is accomplished by a combination of the containment spray system and the Containment Area Recirculation (CAR) coolers, which are required by the technical specifications in modes 1, 2, & 3. The CAR system consists of two independent trains of two coolers each. The CAR coolers transfer energy from the containment atmosphere to a closed cooling water system to the ultimate heat sink. The containment heat removal capability of one CAR train is considered equivalent to one CS train. Following a main steam line break or loss of coolant accident inside containment in mode 3 with RCS pressures less than 1750 psia, the CAR coolers are the only technical specification required system that satisfies the RCS decay heat removal safety function. Currently the CAR function is not included as part of the RHR performance indicator. Its inclusion would result in the system required hours being equivalent to the total hours for a calendar quar

For the purposes of reporting the RHR performance indicator, should we continue to maintain the current 99-02 methodology which could result in required system hours less than the total calendar hours for a given quarter, or should we be monitoring the availability of the CAR System as part of the RHR performance indicator? If we add the CAR coolers to the RHR performance indicator, how should they be handled in the technical specification modes where both the containment spray and CAR coolers are required (modes 1, 2 and 3 with RCS pressures greater than 1750 psia) versus the technical specification mode where only the CAR coolers are required (mode 3 with RCS pressures less than 1750)?

Response Yes, continue to maintain the current 99-02 methodology with the understanding that frequent plant shutdowns or associated mode 3 repairs could result in an accounting mis-match between RHR system required hours and the total calendar hours for a given quarter.

ID 298

Posting Date 01/25/2002

Question **Appendix D - CE Plants (ANO-2, Calvert Cliffs, Fort Calhoun, Millstone 2, Pallisades, Palo Verde,San Onofre, St. Lucie, and Waterford 3)**

FAQ 172 was approved May 2, 2000, for use by CE plants and is now in Appendix D. This FAQ allowed licensees to choose between either of the following two options for reporting historical data:

1. Maintain train 1 and 2 historical data as is. For trains 3 and 4, repeat train 1 and train 2 data.

2. Recalculate and revise all historical data using this guidance.

However, the Containment Spray (CS) system(train 1 and 2) is required to be operable in modes 1,2, and 3, while the Shutdown Cooling (SDC) system is only required to be operable in Modes 4,5 and 6. Therefore the potential exists for the RHR SSU PI to be artificially low because of the higher than actual number of required hours reported for the denominator. As a result, as CE plants began to report the correct number of unavailable and required hours for the SDC trains at the start of Initial Implementation, some of them have shown a declining trend in performance due in part to the decreasing denominator.

Is it acceptable to add a third option, as described below, and allow CE plants to choose to use either option 1, 2 or 3?

3. Maintain trains 1 and 2 historical data as is and make a best effort to collect and report the historical unavailable and required hours for trains 3 and 4, or, if historical data are not available, to make an estimate of those hours?

Response Licensees may use Option 3. If any estimates of unavailable or required hours are used, they must be supported by a description of and a rationale for the estimating method, and any changes to the data must be explained in the comment field of the PI report.
Licensees who used Option 2 need not change their reported historical data.

Licensees who used Option 1 need not change their reported historical data unless the ratio of unavailable hours to required hours for the actual data submitted for trains 3 and 4 since the start of initial implementation (either 1Q00 or 2Q00, as applicable) exceeds 0.010. If and when this occurs, licensees should use either Option 2 or Option 3 to generate enough historical data to calculate a 12-quarter average.

ID 276

Posting Date 08/16/2001

Question FAQ 276 has been withdrawn and replaced by FAQ 283.

Response

ID 267

Posting Date 05/02/2001

Question **Appendix D: Calvert Cliffs Units 1 and 2**

Calvert Cliffs monitors the Safety System Unavailability Performance Indicator for PWR RHR using the guidance in NEI 99-02 provided for Combustion Engineering (CE) designed plants. When a unit is in Mode 6 and with water level in the Refueling Pool, at 23 feet or more above the top of the irradiated fuel assemblies seated in the reactor vessel, the Technical Specifications only require one Shutdown Cooling (SDC) loop to be operable and in operation. Unlike most of the other CE designed plants, at Calvert Cliffs, the two SDC loops on each unit have a common suction piping line. As a result, to permit required local leak rate testing and other maintenance activities on this common suction line, both trains of SDC would be taken out-of-service. Recognizing this plant specific design feature, the Technical Specifications specifically allow this required testing and maintenance to be performed without entering the action statements while the plant is in this particular condition. While the SDC trains are unavailable, decay heat is removed by natural convection to the volume of water in the Refueling Pool. Calvert Cliffs Technical Specifications Bases indicates that "a minimum refueling water level of 23 feet above the irradiated fuel assemblies seated in the reactor vessel provides an adequate available heat sink." In this situation, should unavailable hours be counted against the SDC loop given the plant design at Calvert Cliffs?

Response It is appropriate to not count unavailable hours for the above-described situation at Calvert Cliffs. Removing the SDC suction headers from service for the circumstances specifically allowed by the applicable Technical Specification is a reflection of plant design rather than an indication of adequate component or train maintenance practices. Unavailable hours would be counted while operating in accordance with this applicable Technical Specification if a situation occurred that required entering the action statement.

ID 263

Posting Date 04/04/2001

Question **Appendix D - South Texas Units 1 and 2**

NEI 99-02 Revision 0 requires the Residual Heat Removal (RHR) system to satisfy two separate functions:

* The ability to take a suction from the containment sump, cool the fluid, and inject at low pressure into the RCS

* The ability of the RHR system to remove decay heat from the reactor during a normal unit shutdown for refueling or maintenance

These functions are completed by the Emergency Core Cooling System on most Westinghouse PWR designs. South Texas Project has a unique design for these functions completed by two separate systems with a shared common heat exchanger. How should unavailability be counted for South Texas Project?.

Response Due to the unique design South Texas project, unavailability will be determined as follows:
* In plant Modes 1, 2, 3, and 4 South Texas Project will count the unavailability of the Low Head Safety Injection Pump and the flowpath through its associated RHR Heat Exchanger as the hours to count for the RHR performance indicator. This equipment and flowpath satisfies the requirement to "take a suction from the containment sump, cool the fluid, and inject at low pressure into the RCS". The RHR pump does not contribute to the performance of this safety function since it can not take suction on the containment sump.

*In plant Modes 4, 5, and 6 South Texas Project will count the unavailability hours of the RHR Pump and the flowpath through its associated RHR Heat Exchanger as the hours to count for the RHR performance indicator. This equipment and flowpath satisfies the requirement to "remove decay heat from the reactor during a normal unit shutdown for refueling or maintenance". The RHR loop is required to be isolated from the Reactor Coolant System in Modes 1, 2, and 3 due to the system design. This requirement prevents the system from performing its intended cooling function until plant pressure and temperature are lowered to a value consistent with the system desig

Overlap times when both functions/systems are required will be adjusted to eliminate double counting the same time periods.

This position is consistent with the direction published in Frequently Asked Question #149.

ID 236

Posting Date 01/10/2001

Question **Appendix D Indian Point 2, Indian Point 3**

The ECCS designs for Indian Point 2 and Indian Point 3 include two safety injection recirculation pumps, the recirculation sump inside containment, piping and associated valves located inside containment, and two RHR/LHSI pumps, piping, containment sump (dedicated to RHR pumps), two RHR heat exchangers and associated valves. These two subsystems are identified in the Technical Specifications and FSAR. The RHR/LHSI system is automatically started on an SI, takes suction from the RWST as do the high head SI pumps (3), provides water in the injection phase of an accident, and is secured during the transfer to the recirculation phase of the accident. The recirculation pumps remain in standby in the injection phase and are started by operator action during switchover for the recirculation phase. The recirculation pumps (2) take suction from their dedicated sump and have the capability to feed the low head injection lines, the containment spray headers, and the suction of the high head SI pumps for high head injection. The RHR head exchangers can provide cooling for both the RHR and recirculation flowpaths. The recirculation pumps are inside containment and can not be tested

during operation

The RHR pumps perform the normal decay heat removal function during shutdown operations, and can also be aligned for post accident recirculation. However, the two redundant recirculation pumps represent the primary providers of the low head recirculation function. If a single active failure were to occur, then one recirculation pump would remain available and provides sufficient capacity to meet the core and containment cooling requirements. Only in the event of a passive failure or multiple active failures would it be necessary to align the RHR pumps for recirculation. Use of the RHR pumps for recirculation requires opening two motor operated valves aligned in series to allow suction from the containment sump.

How should the recirculation subsystem unavailability be reported under the mitigating system PI for RHR.

Response The Safety System Unavailability Performance Indicator for RHR monitors two functions:
1. The ability of the RHR system to draw suction from the containment sump, cool the fluid, inject at low pressure to the RCS, and

2. The ability of the RHR System to remove decay heat from the reactor during normal shutdown for refueling and maintenance.

At Indian Point Units 2 & 3, the two SI Recirculation Pumps and associated valves and components should be counted as two trains of RHR providing post accident recirculation cooling, function 1. The two RHR pumps and associated valves and components should be counted as two trains of RHR providing decay heat removal, function 2. The RHR Heat Exchangers and associated components and valves which serve both RHR and recirculation functions should be shared by an RHR and an SI Recirculation Pump train, functions 1 and 2.

The two RHR pumps are also capable of providing backup to function 1. Except as specifically stated in the indicator definition and reporting guidance, no attempt is made to monitor or give credit in the indicator results for the presence of other systems (or sets of components) that add diversity to the mitigation or prevention of accidents. The RHR pump suction flowpath from the Containment Sump provides passive failure mitigation features which, while supporting a system diversity function, are not included as part of the RHR system components monitored for this indicator.

Four (4) trains should be monitored as follows:

Train 1 (shutdown cooling mode)

"A" train consisting of the "A" RHR pump, "A" RHR heat exchanger, and associated valves.

Train 2 (shutdown cooling mode)

"B" train consisting of the "B" RHR pump, "B" RHR heat exchanger, and associated valves.

Train 3 (recirculation mode)

"A" train consisting of the "A" SI Recirculation pump, "A" RHR heat exchanger, and associated valves.

Train 4 (recirculation mode)

"B" train consisting of the "B" SI Recirculation pump, "B" RHR heat exchanger, and associated valves.

The required hours for trains 1 & 2 differ from trains 3 & 4, and will be determined using existing guidelines. Reporting of RHR data should follow this guidance beginning with the first quarter 2001 data submittal.

ID 222

Posting Date 10/31/2000

Question Are there times when RHR Shutdown Cooling can be removed from service without incurring unavailable hours, if allowed by Technical Specifications (i.e., reactor level and temperature requirements met).

Response Yes. Unavailable hours are counted only for periods when a train is required to be available for service. However, Technical Specifications that require one subsystem remain operable and in operation above a specified temperature would be counted if one subsystem were not available or an alternate method (normally specified in the Technical Specification Action Statement) were not available.

ID 221

Posting Date 10/31/2000

Question Function 2 of the RHR Performance Indicator monitors the ability to remove decay heat during a normal heat unit shutdown. The 2 SDSC HX's at Calvert Cliffs are supplied RCS fluid by 2 SDC pumps via a common suction and common discharge header (not single failure proof). The SDC HX's are cooled by the Component Cooling (CC) Water system. The CC system is a closed system that exchanges heat to the Salt Water system via two parallel heat exchangers (CCHX). Component Cooling is always operated cross tied before and after the CCHX's. When one of the two SW trains is removed from service only one CCHX is available. Two saltwater pumps, with independent power, are available as well as 2 component cooling water pumps with independent power. In Mode 5, RCS Loops filled, Technical Specification LCO (old: TS 3.4.1.3; ITS: 3.4.7) requires 2 SDC loops (one operable and one in operation assuming no S/G's available). We consider that one SDC loop is unavailable (SDC HX's and SDC pumps) if one Salt Water train is removed from service. Is this a proper interpretation of NEI

99-02 guidelines?

Response Yes. Assuming the Salt Water System is a necessary support system, and the Salt Water System can provide the cooling for Component Cooling sufficient to remove heat for one loop of SDC. However, when one train of the Salt Water System is removed from service, you no longer meet the Support System Unavailability guidance of NEI 99-02 for not reporting unavailable hours. In this situation you are required to report unavailable hours for one train of the monitored system (i.e., SDC.), since one loop of SDC is available and in operation and the other loop cannot be made available without removing heat removal capability from the operating loop of SDC. If, however, the remaining Salt Water System train is capable of satisfying the heat removal requirements of both trains of SDC, no SDC unavailability would be reported.

ID 183

Posting Date 05/24/2000

Question Our decay heat removal Technical Specifications state that at or below 280 degrees, 2 of the 4 following coolant loops shall be operable:
Reactor Coolant Loop (A) and its associated Steam Generator and at least one associated reactor coolant pump

Reactor Coolant Loop (B) and its associated Steam Generator and at least one associated reactor coolant pump

Decay Heat Removal Loop (A)

Decay Heat Removal Loop (B)

The Low Pressure Injection Technical Specification is not applicable below 300 psig.

With the RCS pressure below 300 psig and RCS temperature below 280 degrees, and with both Steam Generators available for decay heat removal, our technical specifications allow decay heat pumps to be taken out of service. During the time that decay heat removal pumps are out of service and the plant is relying on steam generators for decay heat removal, would any unavailability time be counted?

Response No. During periods and conditions where Technical Specifications allow both shutdown cooling trains to be removed from service the shutdown cooling system is, in effect, not required and required hours and unavailable hours would not be counted.

ID 172

Posting Date 05/02/2000

Question For CE designed NSSS systems, the functions reported under the RHR SSU performance indicator are accomplished by multiple systems. How should CE plants collect and report data for this indicator?

Response ANO-2, Calvert Cliffs, Fort Calhoun, Millstone 2, Pallisades, Palo Verde,San Onofre, St. Lucie, and Waterford 3

Issue: The Safety System Unavailability Performance Indicator for PWR RHR monitors:·

The ability of the RHR system to take a suction from the containment sump, cool the fluid, and inject at low pressure into the RCS, and·

The ability of the RHR system to remove decay heat from the reactor during normal shutdown for refueling and maintenance.

CE ECCS designs differ from the RHR description and typical figures in NEI 99-02. CE designs run all ECCS pumps during the injection phase (Containment Spray (CS), High Pressure Safety Injection (HPSI), and Low Pressure Safety Injection (LPSI)), and on Recirculation Actuation Signal (RAS), the LPSI pumps are automatically shutdown, and the suction of the HPSI and CS pumps is shifted to the containment sump. The HPSI pumps then provide the recirculation phase core injection, and the CS pumps by drawing inventory out of the sump, cooling it in heat exchangers, and spraying the cooled water into containment, support the core injection inventory cooling. How should CE designs report the RHR SSU Performance Indicator?

Resolution: For the first function: "The ability of the RHR system to take a suction from the containment sump, cool the fluid, and inject at low pressure into the RCS."

The CE plant design uses HPSI to "take a suction from the sump", CS to "cool the fluid", and HPSI to "inject at low pressure into the RCS". Due to these design differences, CE plants with this design should monitor this function in the following manner. The HPSI pumps and their suction valves are already monitored under the HPSI function, and no monitoring under the RHR PI is necessary or required. The two containment spray pumps and associated coolers should be counted as two trains of RHR providing the post accident recirculation cooling.

For the second function: "The ability of the RHR system to remove decay heat from the reactor during normal shutdown for refueling and maintenance."

The CE plant design uses LPSI pumps to pump the water from the RCS, through the SDC heat exchangers, and

back to the RCS. Due to this CE design difference, the SDC system should be counted as two trains of RHR providing the decay heat removal function.

Therefore, for the CE designed plants four trains should be monitored, when the particular affected function is required by Technical Specifications, as follows:

Train 1 (recirculation mode) Consisting of the "A" containment spray pump, the required spray pump heat exchanger and associated flow path valves.

Train 2 (recirculation mode) Consisting of the "B" containment spray pump, the required spray pump heat exchanger and associated flow path valves.

Train 3 (shutdown cooling mode) Consisting of the "A" SDC pump, associated flow path valves and heat exchanger.

Train 4 (shutdown cooling mode) Consisting of the "B" SDC pump, associated flow path valves and heat exchanger.

Note that required hours and unavailable hours will be determined by technical specification requirements, not "default hours."

Reporting of RHR data should follow this guidance beginning with the second quarter 2000 data submittal. Historical data was originally reported as two trains. A change report must be submitted to provide historical data for four trains. This can be accomplished in either of two ways:

1. Maintain Train 1 and Train 2 historical data as is. For Train 3 and 4, repeat Train 1 and Train 2 data.
2. Recalculate and revise all historical data using this guidance.

Provide comments with the change report to identify the manner in which the historical data has been revised.

ID 164

Posting Date 05/02/2000

Question Can a Spent Fuel Cooling train be considered an installed spare of Shutdown Cooling under certain conditions? If yes, should unavailable hours be counted during a planned removal from service of the entire Shutdown Cooling System, if it has been demonstrated that a single SFC train will meet the requirements for an installed spare of the shutdown cooling function, and two SFC trains are currently operable?

NEI 99-02, states that an "installed spare" is "a component (or set of components) that is used as a replacement for other equipment to allow for the removal of equipment from service for preventive or corrective maintenance without incurring a limited condition for operation (where applicable) or violating the single failure criteria. To be an "installed spare," a component must not be required in the design basis safety analysis for the system to perform its safety function."

Using the above definition, it would appear a Spent Fuel Cooling System train could be considered an installed spare of the shutdown cooling function under certain conditions: no design basis safety analysis requirement, a connection between the spent fuel pool and reactor vessel, and analysis indicating that under the current conditions the train is adequate to offset the combined vessel and fuel pool decay heat load.

FAQ 17 appears to support the interpretation that SFC can be an installed spare of shutdown cooling under certain conditions.

NEI 99-02 goes on to say that "those portions of the Shutdown Cooling System associated with one heat exchanger flow path can be taken out of service without incurring planned or unplanned unavailable hours provided the other heat exchanger flow path is available (including at least one pump) and an alternate, NRC approved means of removing core decay heat is available."

In the case cited above, each SFC train has taken the place of a Shutdown Cooling System train, as an installed spare. Each SFC train can maintain the core decay heat load within the temperature limits set by the plant's design basis. Therefore, there continues to be a heat exchanger flow path, and an alternate, closed-cycle, forced means of removing core decay heat. Thus, it would appear no unavailable hours need be incurred.

Response The Spent Fuel Cooling train is not an installed spare. However, if the Spent Fuel Cooling system is an NRC approved alternate means of removing decay heat, the hours do not have to count. (Refer to p.32 lines 13-18)

ID 155

Posting Date 04/01/2000

Question If a plant has two, 100% capacity, NRC approved, alternate shutdown cooling trains in operation during a refueling outage, may the plant take credit for these two trains and take both trains of the residual heat removal system out of service at the same time without incurring unavailability?

Response Yes, provided that both alternate means of heat removal are capable of performing the heat removal function when placed in service simultaneously.

ID 153

Posting Date 04/01/2000

Question The 99-02 mitigating system guidance and FAQs indicate that unless we can promptly recover the system, we must count it as unavailable. Is this correct as applied to the RHR Unavailability PI? Our position for the RHR suppression pool cooling/shutdown cooling PI for INPO reporting has been that up to a 5 hour recoverability time is appropriate in contrast to the 99-02 criteria of promptly. We understand its appropriateness for HPCI, RCIC and the diesels since they are expected to automatically and immediately respond to a plant event. Use of this 99-02 criteria will have implications for our work management practices. Use of this criterion makes no sense for a system that does not have to respond automatically to an event.

Response Yes. However, the unavailable hours are not counted provided an NRC approved alternative method of removing decay heat is available.

ID 149

Posting Date 04/01/2000

Question NEI document 99-02 requires monitoring PWR RHR Systems for the following functions:·the ability of the RHR system to take a suction from the containment sump, cool the fluid, and inject at low pressure into the RCS, and ·the ability of the RHR system to remove decay heat from the reactor during a normal shutdown for refueling or maintenance. On Millstone Unit 3, there is a separate system that performs each of the functions. The shutdown cooling/decay heat removal function is monitored by RHS and post accident recirculation function is monitored by RSS. For Millstone Unit 3 removing RHS (which is required for function 2), during Mode 1 does not affect the ability to meet the post accident recirculation function and therefore does not result in any unavailability for post accident recirculation (function 1). NEI 99-02 states that the required hours for residual heat removal is estimated by number of hours in the reporting period since the residual heat removal system is required to be available at all times. Please clarify the mode requirements for the two separate functions and specifically address the following question: Is the system which provides the shutdown cooling function (function 2) required to be monitored for unavailability in all modes even if removing it has no impact on the post-accident recirculation function?

Response Reporting of unavailability hours for multi-system should be counted only during the time the particular affected function is required by technical specifications. The two systems are added together to derive the total hours of RHR unavailability to be reported. Overlap times when both functions/systems are required can be adjusted to eliminate double counting the same incident.

ID 148

Posting Date 04/01/2000

Question NEI 99-02, section 2.2, under "Systems Required to be in Service at All Times", states with fuel still in the reactor vessel, when decay heat is so low that forced flow for cooling purposes, even on an intermittent basis, is no longer required (ambient losses are enough to offset the decay heat load), component planned or unplanned unavailable hours are not reportable. According to our Tech Specs Bases 3.9.7, "...At reactor coolant temperatures < 150°F, natural circulation alone is adequate to provide the required decay heat removal capability while maintaining adequate margin to the reactor coolant temperature (212°F) at which a mode change would occur." However, without stating a given starting temperature the parenthetical clarification may be thermodynamically meaningless. The Tech Spec bases provide that starting temperature, i.e., "less than 150°F". Beginning from any initial temperature < 150°F, reactor coolant temperature may initially increase but only to some equilibrium (which will be less than 212°F). After equilibrium, ambient losses will offset decay heat load. Therefore, planning a common SDC suction window outage (complete loss of RHR) when ambient heat loss's were enough to offset decay heat (reactor loaded, fuel pool gates open, fuel pool cooling in service to keep temps below 150F) has been a past practice. Is this what is meant by the parenthetical condition "ambient losses are enough to offset the decay heat load?"

Response No. If the spent fuel pool cooling system is required to maintain reactor coolant temperatures less than 150 degrees F then ambient losses are not sufficient to offset the decay heat load. Therefore, unavailable hours for the RHR system would be counted.

ID 146

Posting Date 04/01/2000

Question In most plants, the RHR system performs the containment heat removal function (ECCS) and the shutdown cooling (SDC) function using common equipment. There are subsets of RHR equipment which are specific to only one of the functions such as the SDC suction valves from the RCS. Technical specifications generally do not require operability of the SDC function during power operation and activities affecting equipment specific only to SDC function are not tracked as LCOs. Should we monitor SDC specific equipment and report unavailability hours for the SDC function during periods when SDC is not required by technical specifications or monitor only what is required by Tech Specs that are mode specific?

Response Reporting of unavailability hours for a multi-function system should be counted only during the time the particular affected function is required by technical specifications. For RHR, unavailability hours for containment heat removal are counted only when containment cooling is required by tech specs and SDC hours are counted only when the SDC function is required by tech specs. The two are added together to derive the total hours of RHR unavailability to be reported. Overlap times when both functions are required can be adjusted to eliminate double counting the same incident.

ID 145

Posting Date 04/01/2000

Question During refueling outages usually after reload, we conduct 4160 VAC electrical safeguards train bus outages with fuel in the core, but with the Refueling Cavity flooded (greater than 20 feet). As a result, 1 train of RHR cannot be used. Our plant shutdown safety assessment counts the refueling cavity flooded to > 20 feet and the upper internals removed as equivalent to one RHR train. Must we count the 2nd train of RHR as being unavailable when the refueling cavity is flooded?

Response If the PWR method described is an NRC approved alternate method (e.g., alternate method allowed by Technical Specifications) of removing core decay heat, then the RHR unavailability time for the first train would not be counted. If the second train is not required by Technical Specifications, then its unavailable hours would not count.

Mitigating Systems

MS05 Safety System Functional Failures

ID 422

Posting Date 01/17/2007

Question **Appendix D – Generic**

Page 23, line 34, Reporting date: the date of the SSFF is the Report Date of the LER.

Response This event should be counted on the date the LER was submitted, which is the first time
this event was reported. This situation is not considered correction of previously submitted PI data.

ID 328

Posting Date 12/12/2002

Question Review of the Safety System Functional Failure Performance Indicator (PI) by the NRC Resident Inspector questioned whether our LER 2000-006 should have been counted as a functional failure. Regardless of whether this LER constitutes a functional failure or not, there would be no PI threshold change.

LER 2000-006 was submitted to the NRC on September 5, 2000. The LER is entitled "Source Range Detector High Flux Trip Circuitry Outside of Plant Design Basis Due To Revised Local Cabinet Temperature Uncertainty." This LER was coded as 10 CFR 50.73(a)(2)(ii). The LER determined the cause of the plant being outside the design basis was the temperature errors associated with the maximum control room design temperature were not explicitly accounted for when the setpoint was changed in 1973. There were no safety consequences associated with this LER since:

- The Tech Specs do NOT include any reactor trip set point limits for the NIS source range detectors,
- The source range high flux trip is NOT credited in any UFSAR Chapter 14 accident analysis, and
- The intermediate and power range flux trips would be available to provide for termination of a power excursion during a reactor startup or low power operation.

The review of this LER did not determine this was a safety system functional failure since the source range high flux trip is not relied on in the UFSAR. Additional information:

- NEI 99-02, Revision 1 refers to 10 CFR 50.73(a)(2)(v). It does state that paragraphs (a)(2)(i), (a)(2)(ii), and (a)(2)(vii) should also be reviewed for applicability for this PI (these were reviewed and the determination was only section (a)(2)(ii) was applicable),
- NEI 99-02, Revision 1 also refers to NUREG-1022 for additional guidance that is applicable to reporting under 10 CFR 50.73(a)(2)(v),
- NUREG-1022, Revision 2, section 3.2.7, at page 54 defines "safety function" as those four functions listed in the reporting criteriaas described or relied on in the UFSAR and
- NUREG-1022 also adds at page 54, "or required by the regulations." Regulations are being interpreted to include technical specifications.

Is it the intent of NEI 99-02 to solely report safety system functional failures as described or relied on in the UFSAR or is it the intent to additionally incorporate the guidance in NUREG-1022, section 3.2.7 that the failure of any component addressed in the plants Technical Specification constitutes a safety system functional failure whether credited or not in the UFSAR chapter 14 analyses?

Response If failure of the source range detector high flux trip circuitry is reportable per 10CFR50.73 (a) (2) (v), then this counts as a Safety System Functional Failure. Such a determination is outside the scope of NEI 99-02; the issue must be referred to the appropriate branch of the NRC.

ID 144

Posting Date 04/01/2000

Question The guidance on SSFFs regarding reporting of multiple failures could be clearer. Is the intent that if there are multiple failures documented in one LER that each one (failure) be counted by the one report date? So that one report date may be tied to numerous failures?

Response Each individual SSFF counts.

ID 143

Posting Date 04/01/2000

Question In our plant, RCIC is not a safety system and functionally, it provides high pressure makeup which can also be provided by HPCI. For these reasons, RCIC functional failures (as determined for the maintenance rule) are not reportable under 10CFR50.73 (a)(2)(v). Given the above, would RCIC functional failures ever be reported for NEI 99-02?

Response No. The intention of NEI 99-02 is to report only those failures meeting the 10CFR50.73(a)(2)(v) reporting criteria as applied to a specific plant.

ID 10

Posting Date 11/11/1999

Question For those cases where a Tech Spec required action places a system in an inoperable status, is it necessary/required to call this a SSFF? It seems like it should not be counted as a SSFF because the systems can perform their safety function.

Response If the system, upon receipt of a demand signal, would have functioned, then it would not count as a SSFF. The reportability guidelines of NUREG-1022 Revision 1, Event Reporting Guidelines, 10 CFR 50.72 and 50.73, should be used. If the situation is reportable per 10CFR50.73 (a)(2)(v) it should be counted as a SSFF.

ID 9

Posting Date 11/11/1999

Question Should Appendix R issues be covered by this indicator (SSFF) or is it already covered/better covered by the fire protection inspection procedure.

Response This indicator monitors events or conditions that alone prevented, or could have prevented, the fulfillment of the safety function of structures or systems that are needed to a) shut down the reactor and maintain it in a safe shutdown condition, b) remove residual heat, c) control the release of radioactive material, or d) mitigate the consequences of an accident. Appendix R issues have the potential to affect the safety functions of structures and systems and should be evaluated accordingly. The reportability guidelines of NUREG-1022 Revision 1, should be used. If the situation is reportable per 10CFR50.73 (a)(2)(v) it should be counted as a SSFF.

ID 8

Posting Date 11/11/1999

Question Does the functional area of Containment Integrity include systems and equipment associated with secondary containment? Specifically, is standby Gas Treatment an included system? If secondary containment is included, do we also include systems like Hi/Lo Volume purge (BWR-6) or Fuel Bldg. Filtration systems for designs that have a separate system for fuel building (a functional equivalent to secondary containment). Would support systems like annulus pressure control be included?

Response Yes, Standby Gas Treatment is included. The reportability guidelines of NUREG-1022 Revision 1, Event Reporting Guidelines, 10 CFR 50.72 and 50.73, should be used. If the situation is reportable per 10CFR50.73 (a)(2)(v) it should be counted as a SSFF. The other systems identified in the question have the potential to be reported under 10 CFR 50.73 (a)(2)(v) and should be evaluated accordingly.

Mitigating Systems

MS06 MS07 MS08 MS09 MS10

ID 427

Posting Date 03/21/2007

Question Clarify guidance on cascading unavailability to add additional clarification that when a support system is unavailable, maintenance on the train/segment would not have to be reported as unavailable hours; if the maintenance does not make the train/segment unavailable.

Response An existing approved FAQ says:

No Cascading of Unavailability

In some cases plants will disable the autostart of a supported monitored system when the support system is out of service. For example, a diesel generator may have the start function inhibited when the service water system that provides diesel generator cooling is removed from service. This is done for the purposes of equipment protection. This could be accomplished by putting a supported system in "maintenance" mode or by pulling the control fuses of the supported component. If no maintenance is being performed on a supported component and it is only disabled for equipment protection due to a support system being out of service, no unavailability should be reported for the train/segment.

This was to be added to Appendix F, section 1.2.1 Add the following after the last sentence.

If, however, maintenance is performed on the monitored component, then the unavailability must be counted.

For example, If an Emergency Service Water train/segment is under clearance, and the autostart of the associated High Pressure Safety Injection (HPSI) pump is disabled, there is no unavailability to be reported for the HPSI pump. If a maintenance task to collect a lube oil sample is performed and it can be performed with no additional tag out, no unavailability has to be reported for the HPSI pump. If however, the sample required an additional tag out that would make the HPSI pump unavailable, then the time that the additional tag out was in place must be reported as planned unavailable hours for the HPSI pump.

This FAQ takes effect April 1, 2007.

ID 426

Posting Date 02/21/2007

Question Clarify guidance for start demand.

Response Reword page F-19, line 17 to say:

Start demand: Any demand for the component to successfully start (includes valve and breaker demands to open or close). Exclude post maintenance test demands, unless in case of a failure the
cause of failure was independent of the maintenance performed. In this case the demand may be counted as well as the failure.

Effective Date: 07/01/07

ID 425

Posting Date 02/21/2007

Question Clarify guidance on run hours.

Response At the end of the sentence that begins on page F-20, line 18:

It is also permissible to use the actual number of test and operational run hours.

Add the following statement:

(Exclude post maintenance test run hours, unless in case of a failure the cause of failure was independent of the maintenance performed. In this case the PMT run hours may be counted as well
as the failure.)

Effective Date: 07/01/07

ID 424

Posting Date 02/21/2007

Question Section F 2.2.2, *Failures,* subsection *Treatment of Discovered Conditions that Result in the Inability to Perform a Monitored Function*

This section currently addresses:

Discovered conditions of monitored components that render a monitored component incapable of performing its monitored function even though no actual failure on demand or while running existed. This treatment accounts for the amount of time that the condition existed prior to discovery, when the component was in an unknown failed state.

Conditions that render a monitored component incapable of performing its monitored function that are immediately annunciated in the control room. In this instance the discovery of the condition is coincident with the failure. This condition is applicable to normally energized control circuits that are associated with monitored components, which annunciate on loss of power to the control circuit.

Other discovered conditions where the discovery of the condition is not coincident with the failure.

Response This event meets conditions to be counted as described in the guidance in section F 2.2.2 p F-21, Treatment of Discovered Conditions that Result in the Inability to Perform a Monitored Function. For Conditions that render a monitored component incapable of performing its monitored
function that are immediately annunciated in the control room... no additional failure will be counted. In this case there was no immediate annunciation in the control room. Approximately 15 minutes lapsed, while the component was in an unknown state, before it was understood by the control room that, for a brief period of time, the monitored function could not be performed.

This event counts as a failure. No guidance change is needed.

ID 419

Posting Date 01/17/2007

Question **Appendix D Generic**

NEI 99-02, Revision 4 states on page 26, line 37, *Updates to the MSPI coefficients developed from the plant specific PRA will be made as soon as practical following an update to the plant specific PRA. The revised coefficients will be used in the MSPI calculation the quarter following the update. Thus, the PRA coefficients in use at the beginning of a quarter will remain in effect for the remainder of that quarter.*

Should changes to the CDE database that reflect changes to the plant specific PRA or plant specific MSPI basis document be completed before the beginning of a quarter in order for the changes to apply to the quarter?

Response No. The MSPI coefficients used to support MSPI calculations for a quarter should reflect the plant specific PRA of record at the beginning of the reporting quarter. Changes to the CDE database and MSPI basis document changes that are necessary to reflect changes to the
plant specific PRA of record should be incorporated as soon as practical but need not be completed prior to the start of the reporting quarter. Changes to the MSPI coefficients (using the plant specific process for updates) should be completed prior to making the quarterly data submittal for the quarter in which they become effective. The quarterly data submittal should include a comment that provides a summary of any changes to the MSPI coefficients.

For example, if a plants PRA model of record is approved on September 29 (3^{rd} quarter), MSPI coefficients based on that model of record should be used for the 4^{th} quarter. The calculation of the new coefficients should be completed (including a revision of the MSPI basis document if required by the plant specific processes) and input to CDE prior to reporting the 4^{th} quarters data (i.e., completed by January 21).

ID 418

Posting Date 01/17/2007

Question Pages F-18, lines 8-10 and F-19, line 1 state: *For control and motive power, only the last relay, breaker or contactor necessary to power or control the component is included in the monitored component boundary. For example, if an ESFAS signal actuates a MOV, only a
relay that receives the ESFAS signal in the control circuitry for the MOV is in the MOV boundary. No other portions of the ESFAS are included.*

Licensees have expressed difficulty interpreting the guidance as written.

Response The definition of a supporting component as described in the EPIX guidance, INPO 98-001 provides a better description of the intent for component boundaries with respect to control circuits. For control and motive power, if the relay, breaker or contactor that fails is solely used to support the operation of a single monitored component, it should be considered part of the component boundary, regardless of the physical location of the component. If the relay, breaker or contactor supports multiple monitored components, it should not be considered as part of any monitored component boundary.

Example 1: If a limit switch in an MOV fails to make-up, which fails an interlock and prevents a monitored pump from starting, and the limit switch has no other function, a failure to start should be assigned to the pump. If the limit switch prevents both the pump and another monitored valve from functioning, no MPSI failures would be assigned.

Example 2: If a relay prevents an MOV from closing and the relay performs no other function, an MOV failure would be assigned, assuming failure to close is a monitored function of the valve. If the MOV also has a limit switch interlocked with another monitored component, the presence of the limit switch should not be interpreted as the relay having

multiple functions to preclude assigning a failure. If, in addition to the relay failure, there were a separate failure of the limit switch, both an MOV and pump failure would be assigned.

Example 3: If a relay/switch supports operation of several monitored components, failure of relay/switch would not be considered an MSPI failure. However, failure of individual contacts on the relay, which each support a single monitored component, would be considered a failure of the monitored component.

ID 417

Posting Date 10/24/2006

Question The MSPI evaluates both planned and unplanned maintenance. How should the maintenance be classified when both planned and unplanned maintenance are performed in the same work window?

There are times when unplanned maintenance is performed and a plant elects to also perform planned maintenance while the system/train is unavailable (e.g., under clearance to perform the maintenance). Conversely there are times when planned maintenance is performed and either something breaks during the planned maintenance or a condition is discovered that requires additional maintenance that was not planned for initially. In these cases, how should the maintenance be classified?

Response All maintenance performed in the work window should be classified with the classification for which the work window was entered. For example, if the initial work window was caused by unplanned maintenance then the entire duration of the work window would be classified as unplanned even if some additional planned maintenance were added that extended the work window. The other example is if a planned maintenance work window results in adding additional unplanned work due to a discovered condition during the maintenance, the entire work window duration would be classified as planned maintenance.

The following should be added to Section F.1.2.1 of NEI 99-02:

Counting Unavailability when Planned and Unplanned maintenance are preformed in the same work window

All maintenance performed in the work window should be classified with the classification for which the work window was entered. For example, if the initial work window was caused by unplanned maintenance then the duration of the entire work window would be classified as unplanned even if some additional planned maintenance were added that extended the work window. The other example is if a planned maintenance work window results in adding additional unplanned work due to a discovered condition during the maintenance, the entire work window duration would be classified as planned maintenance.

ID 416

Posting Date 09/14/2006

Question The following guidance clarification is requested to be inserted into NEI 99-02:

Discussion

NEI 99-02 Section F.2.2.1 requires that “actual ESF demands”, along with the estimated number of test demands and estimated operational/alignment demands be collected as part of the MSPI calculation. Additional guidance is needed on
what qualifies as an “actual ESF demand.”

Response The following should be added to Section F.2.2.1 of NEI 99-02:

An actual ESF demand is any condition that results in valid actuation, manual or automatic, of any of the MSPI systems
due to actual or perceived plant conditions requiring the actuation. These conditions should be counted in MSPI

as actual ESF demands except when:

1) The actuation resulted from and was part of a pre-planned sequence during testing or reactor operation; or

2) The actuation was invalid; or

3) Occurred while the system was properly removed from service; or

4) Occurred after the safety function had been already completed.

Valid actuations are those actuations that result from "valid signals" or from intentional manual initiation, unless it is part of a preplanned test. Valid signals are those signals that are initiated in response to actual plant conditions or parameters satisfying the requirements for initiation of the safety function of the system. They do not include those which are the result of other signals. Invalid actuations are, by definition, those that do not meet the criteria for being valid. Thus, invalid actuations include actuations that are not the result of valid signals and are not intentional manual actuations.

With regard to preplanned actuations, operation of a system as part of a planned test or operational evolution should not be counted in MSPI as actual ESF demands, but rather as operational or test demands. Preplanned actuations are those which are expected to actually occur due to preplanned activities covered by procedures. Such actuations are those for which a procedural step or other appropriate documentation indicates the specific actuation is actually expected to occur.
Control room personnel are aware of the specific signal generation before its occurrence or indication in the control room.
However, if during the test or evolution, the system actuates in a way that is not part of the planned evolution, that actuation should be counted.

Actual ESF demands occur when the setpoints for automatic safety system actuation are met or exceeded and usually include the actuation of multiple trains and systems. Automatic actuation of standby trains on a failure of a running train should not be considered as an actual ESF demand. Actuations caused by operator error, maintenance errors, etc. that are not due to actual plant requirements should be considered as "invalid" actuations and not counted in MSPI as actual ESF demands.

ID 415

Posting Date 09/14/2006

Question The following guidance clarification is requested to be inserted into NEI 99-02:

Discussion

One of the tenets of MSPI is that it eliminates cascading of support system unavailability onto front line

system.

NEI 99-02, Revision 4 (page 28, line 4-5) states, *“No support systems are to be cascaded onto the monitored systems, e.g., HVAC room coolers, DC power, instrument air, etc.”*

There are times when a support system is unavailable (e.g., under clearance to perform maintenance). This unavailability is not cascaded onto the supported systems. An example would be support cooling water for an EDG. If the
support cooling water system is out of service, the EDG would be unable to perform its risk significant function. However,
this would not be reported as unavailability under MSPI for the EDG.

In some cases, for equipment protection, plants will disable the autostart of a monitored component when the support system is out of service. This is done for the purposes of equipment protection. This could be accomplished by
putting the monitored component in "maintenance" mode or by pulling the control fuses of the monitored component.

Clarification of NEI 99-02 guidance is requested to address situations where a monitored component is disabled, in response to a support system being unavailable.

Response If no maintenance is performed on the supported system and it is only disabled for equipment protection due to a support system being out of service, no unavailability should be reported for the train/segment.
Reporting unavailability of the train/segment would be equivalent to cascading unavailability.

The following should be added to Section F.1.2.1 of NEI 99-02:

No Cascading of Unavailability

In some cases plants will disable the autostart of a supported monitored system when the support system is out of service. For example, a diesel generator may have the start function inhibited when the service water system that
provides diesel generator cooling is removed from service. This is done for the purposes of equipment protection. This
could be accomplished by putting a supported system in "maintenance" mode or by pulling the control fuses of the
supported component. If no maintenance is being performed on a supported component and it is only disabled for equipment
protection due to a support system being out of service, no unavailability should be reported for the train/segment.

ID 413

Posting Date 06/14/2006

Question **Appendix D San Onofre**

During March 2006, the San Onofre Nuclear Generating Station (SONGS) completed the MSPI Basis Document. The MSPI Basis Document contained a calculation of the FV/UA values for the CCW and SWC systems. The FV/UA values were derived by assuming that Train A is constantly running for the entire year and therefore all unavailability would be assigned to the non-running Train B. The resultant FV/UA value for Train B was then conservatively applied to both Train A and Train B without averaging.

Since the system is symmetric in importance, what should have occurred is that the FV/UA values should have been calculated for each train and averaged since each train is run approximately 50% of the time. This would be equivalent to calculating each trains FV/UA value assuming the other train is running and then multiplying each

trains FV/UA value by an operating factor the percentage of time the respective train is actually the running train (approximately 50% in this case) and then averaging the two (Train A and Train B) FV/UA values.

In summary, an error was made in application of the NEI 99-02R4, Section F.1.3.4 guidance.

Response The SONGS misapplication of the guidance in NEI 99-02R4 regarding the treatment of FV/UA due to the modeling asymmetries of the SSC systems were discussed with the NRC at the May 18 Reactor Oversight Process Task Force public meeting. It was concluded that the MSPI Basis Document of April 1, 2006 was in error and requires correction to reflect the train averaging of section F 1.3.4 prior to submittal of the 2Q06 data on July 21, 2006.

ID 410

Posting Date 04/20/2006

Question **Appendix D (Turkey Point)**

For the MSPI truncation requirements, three methods were provided whereby licensees could demonstrate sufficient convergence for PRA model acceptability for MSPI. If a licensee is unable to demonstrate either: (1) a truncation level of 7 orders of magnitude below the baseline CDF or (2) that Birnbaum values converge within 80% for event with Birnbaum values >1E-6 or (3) that CDF has converged within 5% when using the approach detailed in section F.6.

What if a licensee, due to limitations with their PRA can come close but not meet either of these requirements?

Is our approach described in the MSPI basis document excerpted below acceptable, given that the 5% guideline is exceeded by only 0.2%, and that we cannot reduce the increase in CDF due to the last decade decrease in truncation further due to hardware/software limitations?

What should be done in the future when model updates may result in a different degree of compliance with the truncation guidelines, e.g., the increase in CDF due to the last decade decrease in truncation is, say, now 6% instead of 5.2%?

NEI 99-02 Guidance needing interpretation (include page and line citation):

Appendix F, Sections F.6, page F-48, which states: *The truncation level used for the method described in this section should be sufficient to provide a converged value of CDF. CDF is considered converged when decreasing the truncation level by a decade results in a change in CDF of less than 5%*

Event or circumstances requiring guidance interpretation:

As documented in the Turkey Point MSPI Basis document, due to limitations with Turkey Points PRA they were only able to achieve a truncation of 3E-11 per year, and the increase in CDF due to the last decade decrease in truncation is 5.2%, only slightly greater than the 5% guideline.

Turkey Points Basis Document states in part:

The baseline CDF is 4.07E-6 per year, quantified at truncation of 1.0E-11 per year. This truncation is about five-and-a-half orders of magnitude below the baseline CDF. Attempts to quantify at lower truncations failed due to

hardware/software limitations; therefore, the "7 orders of magnitude less than the baseline CDF" criterion defined in the first paragraph of Appendix F, Sections 1.3.1 and 2.3.1 cannot be met. However, an alternative is described in the second paragraph of these sections. For all MSPI basic events with a Birnbaum importance of greater than 1E-6, If the ratio of the Birnbaum importances calculated at one decade above

The lowest truncation (for our case, 1E-10 per year) to their Respective importances calculated at the lowest truncation (for our case, 1E-11 Per year) is greater than 0.8, then the baseline CDF cutset file at the Lowest truncation can be used to generate the MSPI Birnbaum importances.

Turkey Point meets this criterion for all but a few of the MSPI basic events with a Birnbaum importance of greater than 1E-6. The Birnbaum importances for these basic events were calculated using the alternative described in Section 6 of Appendix F. This alternative allows the user to calculate the Birnbaum importances by regenerating cutsets provided the truncation level is "sufficient to provide a converged value of CDF. CDF is considered to be converged when decreasing the truncation level by a decade results in a change in CDF of less than 5%."

For Turkey Point, at 1E-11 per year, the increase in the baseline CDF due to the last decade decrease in truncation is 4.1%, meeting this criterion. However, when the Birnbaum calculations were attempted at a truncation of 1E-11 per year, the runs failed due to hardware/software limitations. This was most likely due to the fact that many more cutsets were being generated due to the quantification of the model with an important component out of service. However, the quantification of these Birnbaum importances via regeneration was possible at a truncation level of 3E-11 per year. This is the truncation that was used to calculate the Birnbaum importances for the few basic events in the MSPI calculation that did not meet the "0.8" criterion. Birnbaum importance is not input into the MSPI calculation, FV importance is, and the Birnbaum importance is calculated using the FV, the basic event probability (p), and the baseline CDF. The FV for these basic events was calculated using the formula below.

FV = B*p / CDF(baseline)

The MSPI calculation takes the FVs calculated in this manner, divides them by their respective basic event probabilities, and multiplies the results by the baseline CDF input to the MSPI calculation, which is the CDF baseline calculated at a truncation of 1E-11 per year. This will effectively apply a "correction factor" to the Birnbaum equal to the ratio of the baseline CDF calculated at a truncation of 1E-11 per year and the baseline CDF calculated at a truncation of 3E-11 per year. This correction Factor should serve to allay any concerns over using a slightly higher truncation level for quantification of the Birnbaum importances for these basic events. Further, at a truncation of 3E-11 per year, the increase in CDF due to the last decade decrease in truncation is 5.2%, just Slightly greater than the 5% guideline."

Response It is acknowledged that there may be limitations with PRA software modeling such that a few licensees may not meet the explicit guidance limits for truncation and convergence.

In such cases, the licensee shall submit a FAQ and present the details of their analyses. Approval will be on a case by case basis.

For Turkey Point, their model was able to approach 5.2% (vice 5%) convergence and that is considered sufficient for the purposes of MSPI calculation.

Mitigating Systems

MS10 MSPI Cooling Water Systems

ID 412

Posting Date 05/17/2006

Question **Appendix D: Prairie Island and Surry Stations**

Prairie Island has two diesel-driven service water pumps that are monitored under MSPI. Surry has 3 diesel-driven service water pumps that are monitored under MSPI. There is no industry prior information associated with this component type on Table 4 on page F-37

Response Due to insufficient industry data upon which to develop a separate set of parameters for this component type, an existing component type should be chosen. Given that the failures for this type of pump are expected to be dominated by the driver rather than the pump, the diesel-driven AFW pump component type should be used.

Barrier Integrity

BI01 Reactor Coolant System Specific Activity

ID 288

Posting Date 09/12/2001

Question Our Chemistry Dept was questioned as to whether or not RCS strip isotopic data was included in the PI reporting for RCS Specific Activity. [We had not been reporting results from that method since it wasn't exactly like the method we typically use to satisfy our Tech Specs.] BVPS uses the RCS Isotopic Iodine Analysis method which is specific for isotopic Iodine in RCS (and is more accurate) for meeting our Tech Spec requirement. (We use all results even if the number of samples exceeds the TS requirement.) We also perform an RCS Strip Isotopic Analysis which is for gaseous and all other liquid isotopes in the RCS. This Strip method however, will provide isotopic Iodine in the results (although less accurate.) This method sometimes provides a higher value than the highest Iodine Isotopic analysis I-131 data for the month. However, this method is also considered to be an acceptable method for meeting the Tech Spec requirement, and is used if problems are encountered with the Isotopic Iodine method. Should ONLY the RCS Isotopic Iodine Analysis method (most accurate) for RCS samples be used for the results and determination of maximum RCS Specific Activity to be reported? or Should ALL isotopic samples of RCS, including those using less accurate analytical methods (e.g. Stripped liquid method) be considered for determination of maximum RCS Specific Activity?

Response Use the results of the method that was used at the time to satisfy the technical specifications.

ID 266

Posting Date 05/02/2001

Question **Appendix D: Cook Units 1 and 2**

The definition for the Reactor Coolant System (RCS) Leakage performance indicator is "The maximum RCS Identified Leakage in gallons per minute each month per the technical specification limit and expressed as a percentage of the technical specification limit."

Cook Nuclear Plant Unit 1 and 2 report Identified Leakage since the Technical Specifications have a limit for Identified Leakage with no limit for Total Leakage. Plant procedures for RCS leakage calculation requires RCS leakage into collection tanks to be counted as Unidentified Leakage due to non-RCS sources directed to the collection tanks. All calculatedleakage is considered Unidentified until the leakage reaches an administrative limit at which point an evaluation is performed to identify the leakage and calculate the leak rate. Consequently, Identified Leakage is unchanged until the administrative limit is reached. This does not allow for trending allowed RCS Leakage. The procedural requirements will remain in place until plant modifications can be made to remove the non-RCS sources from the drain collection tanks. What alternative method should be used to trend allowed RCS leakage for the Barrier Integrity Cornerstone?

Response Report the maximum RCS Total Leakage calculated in gallons per minute each month per the plant procedures instead of the calculated Identified Leakage. This value will be compared to and expressed as a percentage of the combined Technical Specification Limits for Identified and Unidentified Leakage. This reporting is considered acceptable to provide consistency in reporting for plants with the described plant configuration.

ID 262

Posting Date 04/04/2001

Question NRC Performance Indicator BI-01 monitors the integrity of the fuel cladding. We are required to report the maximum monthly RCS activity in micro-Curies per gram dose equivalent Iodine-131 and express it as a percentage of the technical specification limit.
FAQ 226 asks if licensees with limits more restrictive than the technical specification limit should use the more restrictive limit or the TS limit. The FAQ answer states that the licensee should use the most restrictive regulatory limit unless it is "insufficient to assure plant safety." If administrative controls are imposed "... to ensure that TS limits are met and to ensure the public health and safety, that limit should be used for this PI."

Vermont Yankee has a Basis for Maintaining Operation (BMO) that is in effect that limits the Reactor Coolant System to 0.05 uCi/gm I-131 dose equivalent. This BMO, 98-36, entitled "Effect of Main steam Tunnel and Turbine Building HELBs on the HVAC Rooms," is concerned with Control Room habitability and the regulatory dose limits to the operators. It states that there is no concern with increased radiological dose to the public from the VY HELB off-site dose analyses in FSAR Section 14.6.

FAQ 226 mentions the concern for both assuring plant safety and public health and safety as the intent for the more restrictive administrative controls that may be in effect. NRC Administrative Letter 98-10, which is mentioned in the answer to this FAQ, states in the Discussion that the concern is the safe operation of the facility.

Our question is this: "Is Vermont Yankee required to use the lower administrative limit imposed by the BMO (0.05 uCi/gm I-131 dose equivalent) even though public health and safety is not compromised if this limit is exceeded?"

Response No. The intent is when administrative limits are required to ensure 10 CFR Part 100 limits are not exceeded.

ID 251

Posting Date 02/08/2001

Question In the clarifying notes section of the Reactor Coolant System Leakage indicator, required data is identified as, "All calculations of RCS leakage that are computed in accordance with the calculational methodology requirements of the Technical Specifications are counted in this indicator."

Within our Technical Specifications identified leakage is calculated on a set frequency using a surveillance procedure. The procedure measures various drain and relief tank levels over time and requires the test to be run for at least 120 minutes to produce acceptable results. The test is required to be performed at steady state conditions to guarantee accuracy.

During off-normal conditions, for example leakage past a drain valve of a pump, control room operators may estimate leakage by monitoring drain/relief tank level over time and produce a leakage value within a few minutes. This estimation does not meet the Technical Specification surveillance prerequisites, the acceptance criteria, does not maintain the same measurement accuracy, and does not meet the surveillance requirements. The only similarity is that a tank level over time is being measured.

Are leakage estimations as described above to be included as part of the data elements for the RCS identified Leakage indicator?

Response No. The TS surveillance procedure was not followed.

ID 226

Posting Date 10/31/2000

Question (This FAQ is a replacement for FAQ 193. FAQ 193 has been withdrawn.)

The definition of the RCS Specific Activity PI is the maximum RCS activity as a percentage of the technical specification limit. Should licensees with limits more restrictive than the technical specifications use the more restrictive limit or the TS limit?

Response Licensees should use the most restrictive regulatory limit (e.g., technical specifications[TS] or license condition). However, if the most restrictive regulatory limit is insufficient to assure plant safety, then NRC Administrative Letter 98-10 applies, which states that imposition of administrative controls is an acceptable short-term corrective action. When an administrative control is in place as a temporary measure to ensure that TS limits are met and to ensure public health and safety, that administrative limit should be used for this PI.

ID 193

Posting Date 10/31/2000

Question FAQ 193 has been withdrawn and replaced by FAQ 226.

Response

ID 177

Posting Date 05/24/2000

Question In the discussion of RCS Activity, NEI 99-02 states:
This indicator monitors the steady state integrity of the fuel-cladding barrier. Transient spikes in RCS Specific Activity following power changes, shutdowns and scrams may not provide a reliable indication of cladding integrity and should not be included in the monthly maximum for this indicator.

Steady state is not defined.

Response If steady state is not defined by the licensee, use the definition in INPO96-003 where steady state is defined as continuous operation for at least three days at a power level that does not vary more than ± 5 percent.

ID 72

Posting Date 03/01/2000

Question Two of the performance indicators for the barrier integrity cornerstone use "technical specification limit" in the calculation. They are RCS specific activity and leakage. There are two situations where a plant could be operating with a more restrictive limit for RCS specific activity and/or RCS leakage than the "technical specification limit". One situation is where the Facility Operating License (FOL) contains a condition that specifies a more restrictive limit. The second situation is where the licensee has administratively implemented a more restrictive limit to maintain operability as described in Generic Letter 91-18. The guidance as currently worded would always use whatever the technical specification limit is and ignore any more restrictive limits. Is that the intent and is that appropriate?

Response The circumstances of each situation are different and should be identified to the NRC so that a determination can be made as to whether alternate data reporting can be used in place of the data called for in the guidance.

ID 84

Posting Date 02/15/2000

Question How many significant digits should be carried for the dose equivalent I-131 maximum value? Although NEI 99-02, has guidance concerning the number of decimal places in the final reported number (percentage of TS limits), it isn't clear how many significant digits to retain in the raw data.

Response In general, the data element input forms allow data to be entered to a level of significance that is one significant figure greater than the resulting performance indicator. In some cases the input forms restrict the level of significance even further due to recognized limitations in reporting accuracy (e.g., compensatory hours are limited to two significant figures even though the PI calculation would allow input to four significant figures). In all cases, however, the accuracy of the raw data should be considered.

ID 25

Posting Date 11/11/1999

Question PWRs can expect RCS Specific Activity spikes following routine shutdowns. Are these spikes to be counted as the monthly maximum?

Response The indicator definition refers to the Technical Specifications maximum monthly activity limit. The basis for this indicator is to monitor steady state power operations. Therefore, do not count short periods of non-steady-state or non-power operation because they may not equate to the current condition of the fuel cladding.

ID 24

Posting Date 11/11/1999

Question Are RCS sample results determined during shutdowns, using the technical specification methodology, required to be reported even if the plant is in a mode that does not require the sample. Administratively, the plant may be in a plant condition that requires the sample and analysis, although it is not required by Technical Specifications.

Response No.

ID 23

Posting Date 11/11/1999

Question Technical Specifications (TS) provide a frequency of reactor coolant sampling and analysis. If sampling and analysis is conducted on a more frequent basis, do you only report the analysis conducted at the TS frequency, or do you consider all the analyzed samples.

Response All analyzed samples obtained during steady state power operation should be considered in reporting the monthly maximum.

ID 22

Posting Date 11/11/1999

Question The Reactor Coolant System Specific Activity performance indicator is based upon a measurement of RCS activity in micro-Curies per gram dose equivalent Iodine-131. Our plants measurement and associated technical specification are based upon micro-curies per gram total Iodine. What do we report for this performance indicator.

Response RCS activity for this indicator is expressed as a percentage of the technical specification limit. The maximum monthly RCS activity and your technical specification limit should be reported on a common basis. In your case RCS activity and the technical specification limit should be reported in micro-Curies per gram total Iodine.

Barrier Integrity

BI02 Reactor Coolant System Leakage

ID 381

Posting Date 03/22/2005

Question NEI 99-02R2, Page 80, lines 33-34 states: For those plants that do not have a Technical Specification limit on Identified Leakage, substitute RCS Total Leakage in the Data Reporting Elements.

The RCS total leak rate at SONGS has historically been approximately 0.1 gpm with the identified leakage being approximately one third of that value (i.e., ~0.03 gpm). Due to low leak rate calculations, instrument uncertainties, and computer modeling, when the total leak rate was less than 1 gpm the identified leak rate equaled or exceeded the total leak rate 55 times from January 2001 to May 2002. Since identified leakage cannot exceed total leakage. SONGS stopped calculating identified leakage if total leakage was less than 1 gpm. The PI reporting requirement is the maximum monthly value of identified leakage but since we do not calculate this unless it is greater than or equal to 1 gpm, we have reported total leakage with an appropriate comment (stating this each month). Even though we have a Technical Specification limit on identified leakage [10 gpm], we have opted to report the more conservative value of total leakage. Is this acceptable?

Response For SONGS, the methodology described in the question is acceptable. Other licensees whose PI is based on identified leakage may apply this methodology - that is, report a more conservative value of total leakage instead of identified leakage - as long as the following requirements are met: the PI threshold remains based on the identified leakage technical specification requirements, and the comment section for each applicable data point is annotated to reflect that total leakage values are reported in place of identified leakage values.

ID 370

Posting Date 09/16/2004

Question River Bend Station (RBS) seeks clarification of BI-02 information contained in NEI 99-02 guidance, specifically page 80, lines 36 and 37 Only calculations of RCS leakage that are computed in accordance with the calculational methodology requirements of the Technical Specifications are counted in this indicator.

NEI 99-02, Revision 2 states that the purpose for the Reactor Coolant System (RCS) Leakage Indicator is to monitor the integrity of the reactor coolant system pressure boundary. To do this, the indicator uses the identified leakage as a percentage of the technical specification allowable identified leakage. Moreover, the definition provided is the maximum RCS identified leakage in gallons per minute each month per technical specifications and expressed as a percentage of the technical specification limit.

The RBS Technical Specification (TS) states Verify RCS unidentified LEAKAGE, total LEAKAGE, and unidentified LEAKAGE increase are within limits (12 hour frequency). RBS accomplishes this surveillance requirement using an approved station procedure that requires the leakage values from the 0100 and 1300 calculation be used as the leakage of record for the purpose of satisfying the TS surveillance requirement. These two data points are then used in the population of data subject to selection for performance indicator calculation each quarter (highest monthly value is used).

The RBS approved TS method for determining RCS leakage uses programmable controller generated points for total RCS leakage. The RBS programmable controller calculates the average total leakage for the previous 24 hours and prints a report giving the leakage rate into each sump it monitors, showing the last four calculations to indicate a trend and printing the total unidentified LEAKAGE, total identified LEAKAGE, their sum, and the 24 hour average. The programmable controller will print this report any time an alarm value is exceeded. The printout can be ordered manually or can be automatic on a 1 or 8 hour basis. While the equipment is capable of generating leakage values at any frequency, the equipment generates hourly values that are summarized in a daily report.

The RBS TS Bases states In conjunction with alarms and other administrative controls, a 12 hour Frequency for this Surveillance is appropriate for identifying changes in LEAKAGE and for tracking required trends.

The Licensee provides that NEI 99-02 requires only the calculations performed to accomplish the approved TS surveillance using the station procedure be counted in the RCS leakage indicator. In this case, the surveillance procedure captures and records the 0100 and 1300 RCS leakage values to satisfy the TS surveillance requirements. The NRC Resident has taken the position that all hourly values from the daily report should be used for the RCS leakage performance indicator determination, even though they are not required by the station surveillance procedure. The Resident maintains that all hourly values use the same method as the 0100 and 1300 values and should be included in the leakage determination.

Is the Licensee interpretation of NEI 99-02 correct?

Response Appendix D

All calculations of RCS leakage that are computed in accordance with the calculational methodology requirements of the Technical Specifications are counted in this indicator. Since the River Bend Station leakage calculation is an average of the previous 24 hourly leakage rates which are calculated in accordance with the technical specification methodology, it is acceptable for River Bend Station to include only those calculations that are performed to meet the technical specifications surveillance requirement when determining the highest monthly values for reporting. The ROP Working Group is forming a task force to review this performance indicator based on industry practices.

ID 349

Posting Date 06/18/2003

Question Plant TS require RCS leakage be determined periodically during steady-state operation but in no case at an interval of greater than 120 hours. In some start-up cases, when the maximum surveillance interval is approached a non-steady state RCS leakage calculation must be taken which can provide an inaccurate indication of RCS leakage (confirmed by subsequent calculations). Additionally, RCS leakage is required to support ISTs of check valves associated with loop injection upon entry into Mode 4 from Mode 5. Both of these conditions result in invalid RCS leakage calculations during non-steady state conditions that can skew the data. When the monthly RCS leakage calculations are reviewed for the maximum monthly result, should invalid calculations made during non-steady state operation be ignored?

Response No. Any RCS leakage determination made in accordance with plant technical specifications are included in the performance indicator calculation.

ID 308

Posting Date 05/22/2002

Question During maintenance, water from the charging pump suction header was aligned to a relief valve which relieves to a boric acid tank. This relief valve unexpectedly lifted below the setpoint tolerance. The relief valve was passing about eighteen gpm to the boric acid tank based on calculations using volume control tank level trend. The source and collection point of the leakage was unidentified until the time that realignment secured the leak. A Notice of Unusual Event was declared due to reactor coolant system (RCS) unidentified leakage greater than or equal to 10 gpm. The duration of this event was approximately thirty-five minutes.
The leak occurred from a piping system outside containment that communicates directly with the RCS (e.g., letdown to the volume control tank). The leak was from a source that would not be automatically isolated during a safety injection signal. The leakage was collected in a tank outside containment that is not considered in the baseline as identified leakage when performing the Technical Specification RCS Leakage surveillance procedure. Note that the WOG STS definition of Identified Leakage is "Leakage that is captured and conducted to collection systems or a sump or collecting tank." Is this leakage to be included in the RCS identified leakage PI?

Response No. The TS methodology provided by the RCS Leakage Calculation Procedure is to be used. The source and collection point of the leakage in this example were unknown during the time period of leakage, and the actual collection point was not a monitored tank or sump per the RCS Leakage Calculation Procedure. Therefore, this is not considered RCS identified leakage to be included in PI data. RCS leakage not captured under the PI should be evaluated in the inspection program.

ID 135

Posting Date 04/01/2000

Question Our Tech Spec requires test/evaluation of primary system leakage 5 times per week. The Tech Spec limits (LCOs) are 1 gpm unidentified and 10 gpm Total. The Reactor Operators perform a daily calculation of RCS leakage based on mass flow differences, which is equivalent to Total leakage from the RCS. The unidentified RCS leak rate is also determined daily based on the daily total but using a weekly calculated Identified leak rate and subtracting it from the daily total leak rate. Based on the NEI 99-02 guideline, we would use the weekly-calculated identified leak rate? Is this correct? This leak rate is sometimes calculated more frequently due to increases in leakage during the week. Many times the identified leak rate is zero. We can look at a months worth of calculations (usually 4) and see which one is the highest and report that. Is that the intent of the PI?

Response Report the highest monthly value computed in accordance with the calculational methodology requirements of the Technical Specifications.

ID 79

Posting Date 01/07/2000

Question We have implemented ITS and have TS definitions for Reactor Coolant leakage. We have a defined limit for "Total Leakage" (25 gpm) and "Un-identified Leakage" (5 gpm). We do not have a specified limit for "Identified Leakage". You can infer directly from our TS limits an identified leakage limit of no more than 20 gpm (25 gpm total minus 5 gpm the amount of leakage we call "unidentified leakage"). Using this approach, the Tech Spec limit for the PI could vary between 25 and 20 gpm depending on the amount of "un-identified leakage" we have. Why cant we use the 20-25 gpm as the limit for the PI as can others who do not have a total leakage TS limit?

The best indicator of barrier performance seems to be "Un-identified Leakage" rather than identified leakage. Unidentified is the amount of leakage falling outside designed collection systems. Trending the percentage of "Un-identified Leakage" presents a more clear picture of how well a plant is maintaining their Reactor Coolant system. It is also very well defined. It also seems to meet the SECY objective to be an indication of the probability of more catastrophic failure potential as specified in para C.4.5. Why is this PI concerned with identified and not Unidentified leakage?

Response NEI 99-02 states that total leakage will be used for those plants that do not have a Technical Specification limit on Identified Leakage. This is considered acceptable to provide consistency in reporting for those plants.Not all plants track total leakage. Identified leakage was chosen as capturing most of the allowed leakage.

Emergency Preparedness

EP01 Drill/Exercise Performace

ID 408

Posting Date 02/23/2006

Question Background:

In the third quarter of 2004, Control Room drills were conducted for DEP PI credit. The same scenario was used for 12 control room simulator crews from July 14 to August 12 during the Operations training week for each crew. The scenario was security related and involved a threat which was not unit specific that resulted in an NOUE, a device (bomb) found in a Unit 1 safety related area resulting in an Alert, and then the device exploded affecting safety related equipment in Unit 1 resulting in a Site Area Emergency declaration. All of the classifications were correct and as predicted by the scenario developers. The question involves the marking of the block **AFFECTED UNIT** as either **Unit 1** or both **Unit 1 and Unit 2** on the notification message form. The compiled results of these drills were as follows:

AFFECTED UNIT marked

Unit 1 and Unit 2:

NOUE message - 10

Alert message - 8

SAE message - 7

Unit 1 only:

NOUE message - 2

Alert message - 4

SAE message - 5

The lead controller, the PI reporter, the PI verifier, and the EP manager all concluded that, given the scenario information, the marking of either **Unit 1 and Unit 2** or marking **Unit 1** only were both acceptable based on the shift managers judgment and stated rationale, since no clear and definitive guidance had previously been provided for this task. Additionally, since Unit 1 normally handles the common station equipment and areas, this could have easily accounted for why the results were biased towards marking **Unit 1** for some crews since that would have been the most affected unit in this scenario. It was also concluded that marking **Unit 2** only or leaving no unit marked (neither of which occurred) would have been clearly inaccurate.

During the review of PI data during the NRC inspection in December 2005, the Regional inspector questioned this conclusion. A call was made to headquarters and the direction was to write an FAQ based on the instructions in FAQ 338, response 1) as follows:

Additionally, any future similar instances should be submitted as an FAQ for evaluation.

Question:

If the lack of providing clear expectations for properly completing sections of a notification form is identified as a programmatic weakness, should the historical DEP PI data be revised to indicate that previous applicable opportunities were inaccurate (failures)?

Response No, the lack of providing clear expectations for properly completing sections of a notification form is indicative of a programmatic weakness and not due to a performance weakness. Therefore, revising the historical data would not provide an indicator of actual performance with regard to the accuracy of the notification form. However, consistent with archived FAQ 338 response, not completing a section of a notification form indicates a lack of performance (regardless of expectations) and shall be considered a failed opportunity the historical data shall be revised accordingly.

ID 401

Posting Date 07/21/2005

Question **Event Description**

During a recent drill at Vogtle, 9 minutes after an EAL condition had been met, the shift manager and shift supervisor were still debating whether a transient had occurred and if the plant was stable, in order to make a decision on the EAL. The controller than asked Is the plant stable? The shift manager acknowledged the question and declared an Alert. In its critique, the licensee identified that the controller may have interfered with the decision, and therefore, determined that no classification opportunity existed. The licensee claims that the opportunity for the shift manager to independently declare the event was removed when the controller asked a question.

Question

If during the performance of a DEP PI opportunity, a controller intervenes in a way (e.g., coaching, prompting) such that the action interferes with an individual making an independent and correct classification, notification, or PAR, shall the DEP PI opportunity be considered a failure, success or a non-opportunity?

Response If a controller intervenes (e.g., coaching, prompting) with the performance of an individual to make an independent and correct classification, notification, or PAR, then that DEP PI opportunity shall be considered a failure.

ID 357

Posting Date 01/22/2004

Question In April 2003, Operations decided to change from marking Drill to marking Actual on the notification forms used in LOR simulator sessions to enhance realism. Emergency Preparedness was unaware of the policy change at the time since only Annual License Exam simulator sessions contribute to DEP.

A LOR trainee questioned the use of actual in mid May 2003 and this question was forwarded to Emergency Preparedness for resolution. EP reevaluated the policy of using Actual based on the recent FAQ 338. We decided to change our practice back to marking the notification forms as Drill during LOR Training as of June 2003. The expectation of how to mark notification forms during LOR simulator training was reviewed with the personnel but notification opportunities in the September NRC Exams were subsequently inconsistently marked as either drill or actual consistent with the trainee understanding of the accuracy expectation of no blank forms. There were 13 notification opportunities with 7 marked Actual and 6 marked Drill. The inconsistent form completion was discovered during EPs review of PI data from the LOR classes for the last three weeks of September in preparing the 3rd Quarter 2003 PI results.

Reasonable assurance exists that the same error would not have occurred for an actual emergency since it is implicitly clear that Actual is to be marked during an actual event. The inconsistent form completion is addressed in the Corrective Action Program.

FAQ 338 provided a plant with the one time site specific allowance to count the forms as accurate with either drill or actual as long as one or the other was checked. The bases for this decision was that the lack of providing clear expectations to the LOR simulator crews on marking drill or actual event on the notification form is indicative of a programmatic weakness and not a performance weakness.

Due to the short duration from the resolution of FAQ 338 and the September NRC exam and the infrequency of the performance of simulator training EP drills, is it acceptable to apply the similar resolution to our plant also on a one time basis? This would allow the notifications to be considered as accurate as long as either actual or drill was selected (completing all the appropriate blocks on the notification form).

Response Yes. For this occurrence only (and only on a one-time basis), the plant may treat the notifications as accurate as long as either actual or drill was selected (completing all the appropriate blocks on the notification form).
For all PI submittals for all plants for the second quarter of 2004 and beyond, all notification forms must be marked consistently, either drill or actual in accordance with the requirements of the licensees emergency preparedness program.

ID 353

Posting Date 08/21/2003

Question NEI 99-02 defines an opportunity for Classification as each expected classification or upgrade in classification. In a recent actual event a utility cleared the criteria for the Alert Classification and reclassified the condition as a Notification of Unusual Event based on then existing plant conditions and proceeded to make the notification of the Classification change. The utilitys approved Emergency Plan permits downgrading Classifications based on changing plant conditions. NEI 99-02 is unclear as to whether the Classification based on the downgrade should count as an opportunity.

Should a Classification based on a downgrade from a previously existing higher classification and the subsequent notification of the downgrade to offsite agencies count as opportunities for the purpose of the DEP Performance Indicator.

Response No: It was not the intent of the NEI 99-02 to count downgrades as opportunities for the DEP performance indicator.

When a higher classification is reached in a drill, exercise or real event it is probable that multiple EALs at equal or lower levels have also been exceeded. When the reason for the highest level Classification is cleared many of these conditions may still exist. It is impractical to evaluate from a timeliness or accuracy standpoint the starting point for the purposes of Performance Indicator assessment. Subsequently, the notification of the downgrade opportunity should then also be handled as an update rather than a formal opportunity for a Performance Indicator

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ID 352

Posting Date 08/21/2003

Question If a scenario predicts that a default protective action recommendation will be used and therefore not counted as an opportunity, can the associated notification be counted as an opportunity?

Response Yes, if a scenario results in the development of PARs (whether default or not) the PAR notification should be counted as an opportunity.

ID 351

Posting Date 08/21/2003

Question STP performs "team training" during licensed operator requalification (LOR) by scheduling on-shift E-Plan drills during concurrent LOR, Plant Operator Requalification (POR) and Health Physics Continuing Training. This allows us to exercise the on-shift ERO as a unit instead of individually in training sessions. We count classification and PAR development opportunities and notification opportunities and evaluate performance during these opportunities.
During these sessions, occasionally the Shift Supervisor , who is the only one allowed to act as Emergency Director in an actual event, requests that the Unit Supervisor perform as the Emergency Director as part of his training for upgrade to full Shift Supervisor qualification. This is recognized and planed for prior to the start for the session. The Unit Supervisor is a licensed SRO and has completed the initial training requirements foe Emergency Director, but can not actually act in that position outside this training environment. This is recognized and planed for prior to the start for the session. Based on NRC regional inspector interpretation and direction we do not count the classification and PAR opportunities since the Unit Supervisor is not counted as key responder in the ERO. We do count the notification opportunities and award ERO participation credit to the non-licensed operators since they are the Key Responders and would actually perform the notifications in an actual event.

Is it allowed to count the classification as an opportunity even though it is performed by the Unit Supervisor who is not defined as a key responder?

Response No. ERO and DEP were developed to be congruent. If the classification is performed by a key ERO member then it must be counted as an opportunity. Conversely, if the classification is performed by an individual who is not a key ERO member, then the classification cannot be considered an opportunity.

NOTE: If the unit supervisor has an active license and could be placed in the Emergency Director position, then consideration of adding the unit supervisor to the KEY ERO list might need to be considered.

ID 350

Posting Date 08/21/2003

Question STP performs "team training" during licensed operator requalification (LOR) by scheduling on-shift E-Plan drills during concurrent LOR, Plant Operator Requalification (POR) and Health Physics Continuing Training. This allows us to exercise the on-shift ERO as a unit instead of individually in training sessions. We count classification and PAR development opportunities and notification opportunities and evaluate performance during these opportunities.
During these sessions, occasionally the Shift Supervisor , who is the only one allowed to act as Emergency Director in an actual event, requests that the Unit Supervisor perform as the Emergency Director as part of his training for upgrade to full Shift Supervisor qualification. The Unit Supervisor is a licensed SRO and has completed the initial training requirements foe Emergency Director, but can not actually act in that position outside this training environment. This is recognized and planed for prior to the start for the session. Based on NRC regional inspector interpretation and direction we do not count the classification and PAR opportunities since the Unit Supervisor is not counted as key responder in the ERO. We do count the notification opportunities and award ERO participation credit to the non-licensed operators since they are the Key Responders and would actually perform the notifications in an actual event.
The simulator scenario scope lists the classification and notification as opportunities in the drill. Both activities are evaluated for proper performance.

Is it allowed to count the notification as an opportunity and award ERO participation credit for the non-licensed plant operator performing the key responder role for notification?

Response Yes. If the communicator performing the entire notification during performance enhancing scenario is a key ERO member, then the notification should be considered as an opportunity and participation credit awarded to the key ERO member.

ID 338

Posting Date 03/20/2003

Question During a recent Nuclear Regulatory Commission (NRC) review of the historical data for the Drill/Exercise Performance (DEP) Performance Indicator (PI), the inspector identified an issue with regard to the evaluation of the accuracy of the initial notification form. During licensed operator requalification (LOR) simulator training, crews were inconsistent in marking the form as a drill or actual event. Further, the inspector noted that the DEP PI notification opportunities were evaluated as successful regardless of whether drill or actual event was marked, or in a couple of instances, not marked at all.

For the purposes of evaluating Drill/Exercise Performance (DEP) PI notification opportunities, NEI 99-02 Revision 2 pg 85 states that the definition of accurate requires that the initial notification form is completed appropriate to the event and includes whether the event is a drill or actual event.
Prior to the Reactor Oversight Process (ROP) and the use of DEP PIs, LOR simulator crews were directed to mark actual on the notification forms to enhance the realism of the training environment, and mark drill during full-scale exercises. Inconsistencies began when there was a lack of clear expectations on how the crews were to mark the initial notification forms during LOR simulator training exercises that were to be included in the DEP PI data. The emergency preparedness staff did not provide direction on what the expectations were for accurately completing the form because they felt it would constitute a disruption of the operator training program.

Following the identification of the issue by the NRC inspector, the emergency preparedness staff established criteria for evaluating the accuracy of the notification form with regard to marking drill or actual event when determining a successful DEP PI opportunity. The simulator crews were directed to mark drill on the notification form during LOR simulator training exercises. However, the historical DEP PI data was not revised to reflect the inconsistency.

1.) Should the historical DEP PI data be revised to indicate that the previous opportunities were inaccurate?

2.) Is it acceptable for a sites EP program requirements to specify marking actual event on the initial notification form during LOR simulator training exercises and to count those DEP PI opportunities as accurate notifications?

Response 1.) No, for this case only. The lack of providing clear expectations to the LOR simulator crews on marking drill or actual event on the notification form is indicative of a programmatic weakness and not a performance weakness. Therefore, revising the historical data would not provide an indicator of actual performance with regard to the accuracy of the notification form. However, those historical notification opportunities that did not have either drill or actual event marked (i.e., left blank) should be revised to a failed opportunity since it indicates a lack of performance. Additionally, any future similar instances should be submitted as an FAQ for evaluation.

2.) Yes, assuming all other portions of the notification form are accurate (IAW NEI 99-02, revision 2, page 85), and meet site specific EP program requirements. A successful PI opportunity is determined evaluating performance against expectations. However, not marking either drill or actual event (regardless of expectations) shall be a failed opportunity.

ID 326

Posting Date 12/12/2002

Question During an EP drill/exercise scenario, a licensee will implement their procedure(s) and develop appropriate protective action recommendations (PARs) when valid dose assessment reports indicate EPA protective action guidelines (PAGs) are exceeded. A question arises when a scenario objective identifies that the PAGs will be exceeded beyond the 10 mile emergency planning zone (EPZ) boundary. Should the licensee count the development of the PAR(s) [or the lack thereof] beyond the 10 mile EPZ as an EP Drill/Exercise Performance (DEP) PI opportunity, due to their "ad hoc" nature?

Response If a licensee has identified in its scenario objectives that PAGs will be exceeded beyond the 10 mile plume exposure pathway emergency planning zone (EPZ) boundary, it is expected that the required PAR development and notification has been contemplated by the scenario with an expectation for success and criteria for evaluation provided. This would constitute a PI opportunity as defined in NEI 99-02. In addition, there is a DEP PI opportunity associated with the timeliness of the notification of the PAR to offsite agencies. Essential to understanding that these DEP PI opportunities exist is the need to realize that it is a regulatory requirement for a licensee to develop and communicate a PAR when EPA PAG doses may be exceeded beyond the 10 mile plume exposure pathway EPZ. However, as discussed in NEI 99-02, the licensee always has the latitude to identify which DEP PI opportunities will be included in the PI statistics prior to the exercise. Thus, a licensee may choose to not include a PAR beyond the 10 mile EPZ as a DEP PI statistic due to its ad hoc nature.

ID 323

Posting Date 10/31/2002

Question Should the follow up PAR change notifications be counted as four inaccurate notifications for the situation described below?
A drill was conducted which included opportunities for Classification, Notification and PARs. The initial Notification for the General Emergency and the associated PAR contained the accurate Time Event Declared of the classification. On follow up PAR change notifications (4), the Time Event Declared block was completed with the time of the PAR data instead of the time the GE was declared. The initial GE Event notification contained the proper time. There were four PAR changes made. The PAR, MET and other required information was accurate. Each PAR developed was accurate. The time the PAR was developed was accurate on the form.

Once a General Emergency was accurately declared, and the INITIAL notification was made in a timely and accurate manner, changing of the time in the Time Event Declared block on the follow up notifications had no influence on the event initiation, nor did it result in untimely or inaccurate PARs being issued to the states and counties. Changing of the time in follow up PAR change notifications did not impact their response since the states and counties were provided the accurate time of event declaration in the initial notification. No additional events were declared since the plant was already at the GE classification. This issue was critiqued and actions were taken to ensure the time desired for the Time Event Declared block on the form was communicated to those responsible for completing the form.

Response No. Based on the example above, the 4 of 5 notifications should be counted as successful. Since it was the same error in 4 follow-up notifications, it should only be counted once since it was in the same exercise. Note: if the same crew made the same mistake in a subsequent exercise, it would be counted as a separate missed opportunity.

ID 309

Posting Date 05/22/2002

Question At one point in the 2001 Off-Year Exercise, a wrong sub-area was identified as part of the affected PAR determination. This PAR determination, including the incorrectly identified affected sub-area, was approved for inclusion in the State notification. The State notification was made to the simulated State responder as approved and in a timely manner. Subsequently, the error in the PAR was discovered and a corrected PAR was developed, approved, and communicated to the simulated State responder, beyond the original 15 minutes. This event was initially counted as three successes out of four opportunities (a successful emergency classification, a successful emergency notification, an unsuccessful PAR determination, and a successful PAR notification). Through discussions with the Senior Resident NRC Inspector, the question was raised concerning whether the paragraph on page 81, lines 6-8, of NEI 99-02, Revision 1 (page 89, lines 4-5 of Revision 2), applies to errors made during PAR determination. The paragraph is clear concerning classification errors, in that one classification error does not cascade to the notifications and PAR. However, a similar paragraph addressing errors made in PARs determination was not found in NEI 99-02. Additionally, the definition of *Accurate* states that the notification form should be completed "appropriate to the event," rather than appropriate to the understanding of the event at that time.

Because the issue had not been resolved at the time of the fourth quarter 2001 NRC PI submittal, this event was reported as two successes out of four opportunities (a successful emergency classification, a successful emergency notification, an unsuccessful PAR determination, and an unsuccessful PAR notification). This FAQ was developed and submitted to clarify whether the PAR notification is considered successful if the PAR information, including the incorrectly identified affected areas, is communicated as approved.

For a failure to properly identify the affected areas for a PAR development, is the notification considered successful if the information, including the incorrectly identified affected areas, is communicated as approved?

Response Yes, for a failure to properly identify the affected areas for a PAR development, the notification is considered successful if the information, including the incorrectly identified affected areas, is communicated as approved. The paragraph describing an incorrect classification as "only one failure" was intended as an example. The situation with PARs is analogous to that described in NEI 99-02 as applied to classification of an event. The Performance Indicator result should be an incorrect opportunity for development of the PAR and a successful opportunity for notification of the PAR (in addition to the successful emergency classification and emergency notification). Hence, in the situation given, this will be considered three successes out of four opportunities.

ID 243

Posting Date 01/10/2001

Question **Part A Indication of the event was available to the operators**

A licensee may discover after the fact (greater that 15 minutes) that an event or condition had existed which met the emergency plan criteria but that no emergency had been declared and the basis for the emergency class no longer exist at the time of discovery. Indication of the event was available to the operators.

a) Should the condition described be considered as a missed classification opportunity?

b) Should the condition described be considered as a missed notification opportunity?

Part B Indication of the event was not available to the operators

A licensee may discover after the fact (greater that 15 minutes) that an event or condition had existed which met the emergency plan criteria but that no emergency had been declared and the basis for the emergency class no longer exist at the time of discovery. Indication of the event was not available to the operators. In determination of whether indications were indeed not available to the operators, the timeliness of necessary calculations, verification efforts, etc. as required by EALs or physical reality, must be considered.

c) Should the condition described be considered as a missed classification opportunity?

d) Should the condition described be considered as a missed notification opportunity?

Response Part A Indication of the event was available to the operators
a) Yes, this classification was not timely.

b) No. NUREG 1022 described the notification requirements for this consideration.

Part B Indication of the event was not available to the operators

c) No, indication of the emergency was not available to operators until the basis for the emergency no longer existed.

d) No. NUREG 1022 describes the notification requirements for this consideration.

ID 242

Posting Date 01/10/2001

Question Can initial notification be considered accurate if some of the elements on that notification form are in error?

Response Yes. NEI 99-02 indicates on page 91, line 27 that accuracy is defined by the approved Emergency Plan and implementing procedures. However, it is realized that functionally, some of the items on an initial notification form may not be significant in that mistakes in that information will not affect the offsite response. The elements which should be assessed for accuracy on the initial notification include:
Class of emergency

EAL #

Description of emergency (Note: the description of the event causing the classification may be brief and should not include all plant conditions. At some sites, the EAL # fulfills the need for a description.)

Wind direction and speed

Whether offsite protective measures are necessary

Potentially affected population and areas

Whether a release is taking place (Note: release means a radiological release attributable to the emergency event.)

Date and time of declaration of emergency

Whether the event is a drill or actual event

Plant and/or unit, as applicable

It is understood that initial notification forms are negotiated with offsite authorities. If the approved form does not include these elements, they need not be added. Alternately, if the form includes elements in addition to these, those elements need not be assessed for accuracy when determining the DEP PI. It is, however, expected that

errors in such additional elements would be critiqued and addressed through the corrective action system

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ID 235

Posting Date 01/01/2001

Question Assume that an event has occurred that has resulted in an Emergency Classification. Subsequently, a utility review of the event reveals that the classification was made conservatively and that, in fact, no emergency classification criterion was exceeded.
Should the event be considered as an opportunity?

Response Yes, the event should be considered as an opportunity. The classification opportunity should not be considered as a success because it was not declared accurately according to the review conducted by the utility.

ID 234

Posting Date 01/01/2001

Question NEI 99-02, Rev 0, page 100, lines 11-15, discusses the role of communicators who provide offsite notifications. A site has identified the TSC and EOF senior managers as communicators for the purposes of tracking drill participation. The basis for this is that these senior manager are responsible for off site notifications because they approve them before they are communicated to off site agencies.
Is this an appropriate interpretation of 99-02?

Response No. The expectation of 99-02 is that the participation of the communicators in drills will be tracked through the ERO Drill Participation PI. The communicator is the key ERO position that collects data for the notification form, fills out the form, seeks approval and usually communicates the information to off site agencies. Performance of these duties is assessed for accuracy and timeliness and contributes to the DEP PI. The senior managers in the above example do not perform these duties and should not be considered communicators even though they approve the form and may supervise the work of the communicator.
However, there are cases where the senior manager actually collects the data for the form, fills it out, approves it and then communicates it or hands it off to a phone talker. Where this is the case, the senior manager is also the communicator and the phone talker need not be tracked.

ID 202

Posting Date 08/30/2000

Question Regarding taking credit for notification performance opportunities, NEI 99-02, page 91 defines opportunities for notifications as those made to the state and/or local government authorities. The guidance further defines timely as those offsite notifications that are initiated must be verbal in nature. On page 92 under clarifying notes (second paragraph), NEI 99-02 states that notifications may be included in the PI if they are performed to the point of filling out the appropriate forms and demonstrating sufficient knowledge to perform the actual notification. This particular note applies to operating shift simulator evaluations, not emergency drills.

Can credit be taken for the notification performance opportunity when notifications are simulated during emergency drills (i.e., not operator simulator evaluations), with no actual verbal contact, as long as the procedures are completed up to the time the notification is made?

Response Yes. 99-02 allows for the simulation of notification of offsite agencies in the case of simulator based drills. There is no reason not to allow the same simulation for other EP drills. However, since the guidance in NEI 99-02 seems specific to simulator drills, it has been interpreted as not allowing such simulation for other drills. (Editorial Note: The guidance will be clarified in a future revision of the document.)

It is not expected that State/local agencies be available to support all drills conducted by licensees. The drill should reasonably simulate the contact and the participants should demonstrate their ability to use the equipment.

ID 198

Posting Date 07/12/2000

Question For expansion of the Protective Action Recommendation (PAR), does the 15 minute assessment period start as soon as any dose projection is received indicating that the PAR might need to be expanded, or when there is sufficient field data to confirm that the PAR needs to be expanded?

Response A conservative approach should be utilized in recognizing the need for PAR expansion. PARs are developed within 15 minutes of data availability. Plant conditions, meteorological data and/or radiation monitor readings should provide sufficient information to determine the need to change PARs. While field monitoring data can be useful, it is not appropriate to wait for that data to become available if other data demonstrate the need to expand the PAR.

ID 197

Posting Date 07/12/2000

Question For sites with multiple agencies to notify, are notifications considered to be initiated when the first agency is contacted or when the last agency is contacted?

The site makes notification to 6 offsite agencies, usually simultaneously using a dedicated telephone line. About 95% of the time, we are able to get all 6 agencies on the line at one time. However, there have been a few cases when we haven't achieved this goal. With six different agencies to contact, there are many things that could go wrong that would prevent getting all of the agencies at one time. There is a thorough backup process in place to deal with these problems and still ensure timely notifications. Furthermore, the dedicated line is tested monthly to ensure its reliability. This question arises for the situation when it doesnt. In such a case, we do sequential calls.

When calling sequentially, it will clearly take longer for a site that has 6 agencies to initiate contact with the 6th agency than it will take for a site that has only 1 agency. The criteria should be clarified to indicate that notifications should be considered timely if verbal contact is made to the first agency within 15 minutes of event declaration.

Response The notification is considered to be initiated when the first agency is contacted. As noted on page 91 of NEI 99-02 in the definition of timely, the offsite notifications are to be initiated (verbal contact) within 15 minutes of classification or PAR development. It should be noted that in many drill situations, the verbal contact may be with a controller rather than the actual offsite agency, or the contact with offsite agencies may be simulated in a manner that otherwise reasonably simulates the interaction.

ID 195

Posting Date 07/12/2000

Question This question pertains to a General Emergency Classification in which the notification of the GE Classification and the notification of the initial PAR for the General Emergency condition are integral. Should this condition count as one or two notification opportunities?

Response Two. As is discussed in Question ID 29 on page 93 of NEI 99-02, notification of the PAR and notification of the GE Classification are separate opportunities, individually subject to the timeliness and accuracy criteria.

ID 173

Posting Date 05/02/2000

Question During an evaluated scenario, the conditions for a General Emergency (GE) were met based on Plant conditions with three barriers breached. The Emergency Director (ED) failed to recognize the classification conditions had been met within 15 minutes. After the 15 minutes, a release occurred and a dose projection was performed which exceeded levels for a GE. The ED recognized this and a GE was declared based on Radiological Conditions and all required notifications and PARs were completed.

(1) Would the first opportunity based on Plant conditions be considered a missed opportunity?

(2) Would a second opportunity be allowed based on Radiological conditions?

(3) If a second opportunity is not allowed can any credit be taken for successfully completing notification and PAR opportunities based on the second opportunity?

Response (1) Yes

(2) No, because it was not the expected timely and accurate classification opportunity as described in the scenario. In some cases, the scenario controllers may prompt the ED to classify with the same result, a failed opportunity to classify.

(3) Yes, credit should be taken for the success or failure of the notification, PAR development and the PAR notification. The subsequent opportunities must not be removed from performance indicator statistics due to poor performance. Additionally, any subsequent PAR changes and the associated notification would also be assessed for timely and accurate completion.

Assuming the notifications and the PAR development were timely and accurate, the result is that three out of four opportunities would be reported as successful in performance indicator statistics.

ID 125

Posting Date 04/01/2000

Question For the purpose of establishing success criteria for the EP DEP PI, how many 15-minute periods could there be for the example situation of a plant initially reaching a General Emergency?

Response The licensee should classify an emergency once the data is available. The licensee should take a prudent approach and not delay classification due to uncertainty. Once the data is available the licensee should classify the event (NUE, Alert, Site Area, or General Emergency) and PAR within 15 minutes. Expectations are that you assess and classify the situation within 15 minutes. If you were done in 5 you should not wait the remaining 10 minutes. The call to the offsite emergency response organizations should be initiated during the next 15-minute time frame. Any changes to classification or PARs should reflect the same 15 minute sequence.Hence there are two 15 minute time frame goals:(1) to determine the classification and PAR, and(2) to initiate notifications to the offsite emergency response agency.

ID 43

Posting Date 11/11/1999

Question May credit for ERO be taken from drills that do not contribute to DEP?

Response If the position performs one of the risk significant EP functions, classification, notification or PAR development, then the drill/exercise used for ERO statistics must contribute to DEP statistics. However, some positions are not responsible for these risk significant functions and participation in a drill that does not contribute statistics to DEP could be credited as participation. For example the OSC Operations Management position could drill without contribution to DEP, as could Health Physics positions not responsible for PARs. The appropriateness including drills involving HP positions responsible for PARs is site specific. Many sites develop PARs through a management review process of the dose projections provided by HP. That being the case, drills involving just the dose projection may not be appropriate for DEP statistics, but may be appropriate for ERO Drill participation statistics.

ID 41

Posting Date 11/11/1999

Question How should performance be evaluated when drill participants properly declare an emergency classification that the scenario did not anticipate?

Response The opportunity may be counted as a success, However, a corrective action should be written against the scenario (or the scenario development process). Another aspect of the same issue is that if a classification is missed that was not anticipated by the scenario, it too should be counted, but as a missed opportunity.

ID 40

Posting Date 11/11/1999

Question What if PI data is not readily available at the end of a quarterly reporting cycle, e.g., a six week operator training cycle begins before the end of quarter, but is not completed until after the quarterly reporting date.

Response The data may be reported in the next quarter, but this practice must be implemented consistently. Inspection will verify that the data is not preferentially reported to manipulate PIs.

ID 39

Posting Date 11/11/1999

Question If the utility holds the ERO to the standard of identifying multiple EALs for the same classification, could multiple opportunities for classification of a particular emergency classification be allowed?

Response This idea has merit and if a proposal were received the Staff would consider it. However, several aspects should be considered in such a proposal including consistent implementation (all opportunities are assessed); consistent evaluation; how does the ERO member document/verbalize the additional EAL; what time frame is acceptable; and will the effort detract from other expected actions.

ID 38

Posting Date 11/11/1999

Question Why are the opportunities for NOUEs and Alerts being treated numerically the same as the ones associated with the more risk significant SAEs and GEs?

Response Although the working group initially considered using weighting factors to emphasize opportunities associated with SAEs and GEs, industry (NEI) guidance suggested that this would unnecessarily complicate the indicator calculation and not be consistent with calculation of the other PIs. PI experts within NRC concurred with this assessment.

ID 37

Posting Date 11/11/1999

Question During drill performance, the ERO may not always classify an event exactly the way that the scenario specifies. This could be due to conservative decision making, Emergency Director judgment call, or a simulator driven scenario that has the potential for multiple forks. How does the program deal with these correct classification determinations that may not follow the path the evaluators were expecting?

Response The NRC realizes that such situations can arise and that the acceptability of the classification may be subjective. In such cases, evaluators should document the rationale supporting their decision for eventual NRC inspection. However, as specified in NEI 99-02, in evaluating the acceptability of the classification, the evaluators have to determine if the classification was appropriate to the event as specified by the approved emergency plan and implementing procedures.

ID 36

Posting Date 11/11/1999

Question Is there not the possibility that PARs could be issued at the SAE level?

Response If PARs at the SAE are in the site Emergency Plan they could be counted as opportunities. However, this would only be appropriate where assessment and decision making is involved in development of the PAR. Automatic PARs with little or no assessment required would not be an appropriate contributor to the PI. PARs limited to livestock or crops and no PAR necessary decisions are also not appropriate.

ID 35

Posting Date 11/11/1999

Question Does success in classification, notification and PARs depend on the individual or team response - could an individual failure to properly classify, notify or develop PARs be corrected by the team and still be counted as a success for this indicator?

Response The measures for successful opportunities under this indicator are accuracy and timeliness. As long as the classification, notification or PARs are timely and accurate, success is established. If the initial error of the individual is identified and corrected so that the timeliness criterion is met, the opportunity is successful.

ID 34

Posting Date 11/11/1999

Question If the ERO fails to identify a GE, does this count as 4 failures: one for the classification, one for the notification of the GE, one for the notification of the PARs and one for the PARs?

Response It will only count as one failure: failure to classify the GE. This is because notification of the GE, development and notification of the PARs are actions that have to be performed as a consequence of the GE classification and that it cant be inferred a posteriori that these actions would have failed.

ID 33

Posting Date 11/11/1999

Question How does this performance indicator evaluate the difficulty of the drill/exercise?

Response In general, PIs are a summary indication of the status of a program element. They are not used to evaluate the details of performance, rather they indicate the need to evaluate the details of performance. This PI was not designed to quantify the difficulty of scenarios. However, NRC inspectors will observe drills and the biennial exercise. If scenarios are inadequate to test the emergency plan, regulatory action may be taken in accordance with Appendix E to 10 CFR 50, Section IVF.f.

ID 32

Posting Date 11/11/1999

Question Why is there not a specified number of facility type drills? a utility could do 60 simulator drills and no EOF drills

Response This concern is addressed through the Emergency Response Organization Drill Participation (ERO) PI, which would show decreasing performance should a licensee go down this path.

ID 31

Posting Date 11/11/1999

Question Would the evaluators for drills or exercises have to be trained in order to assess opportunities correctly?

Response Qualifications or required training for drill/exercise evaluators was not specified because this has not been a problem. There is a good history of competent exercise evaluation by licensees. However, it would be expected that evaluators be knowledgeable of the performance area they evaluate and with the guidance of NEI 99-02 regarding the EP cornerstone.

ID 30

Posting Date 11/11/1999

Question Could it be implied that for each classification opportunity, there may be several associated notification opportunities due to the need to notify several different State/local authorities?

Response For each classification opportunity, there is only one associated notification opportunity even if several different State/local authorities need to be notified.

ID 29

Posting Date 11/11/1999

Question How do you count opportunities for PARs and notifications associated with PARs?

Response The development of an initial PAR and any changes to the PAR (usually no more than one or two follow-up changes due to wind shift or dose assessment) are to be counted. The notification associated with the PAR is counted separately: e. g., an event triggering a GE classification would represent a total of 4 opportunities: 1 for classification of the GE, 1 for notification of the GE to the State and/or local government authorities, 1 for development of a PAR and 1 for notification of the PAR. NEI 99-02 defines the term Opportunity.

ID 28

Posting Date 11/11/1999

Question For an actual event there may be many non-emergency events that require evaluation against the EALs. If this evaluation does not result in a classification, does the actual event count as an opportunity?

Response No it doesnt count as an opportunity. Opportunities begin when a classification is made.

ID 27

Posting Date 11/11/1999

Question Does a tabletop drill count for opportunities?

Response The definition of table-top drill is not clear. However, the licensee has the latitude to include opportunities in the PI as long as the drill (in whatever form) simulates the appropriate level of inter-facility interaction as described in NEI 99-02. Once identified, opportunities cannot be removed from the indicator due to poor performance.

ID 26

Posting Date 11/11/1999

Question How many opportunities per year for evaluating the performance of the Control Room crews are typically available?

Response This will vary depending on the design and structure of the operator training program and the size of the staff. For example, at a single unit plant with 5 operating crews, there are usually about 8 simulator training cycles. Ostensibly, any of these cycles could include opportunities. For estimation purposes, it was assumed that two cycles per year contain a classification and notification opportunity, which results in a total of 20 per year. Additional opportunities could be presented in other parts of the drill/exercise program.

Emergency Preparedness EP01 EP02

ID 411

Posting Date 07/01/2006

Question If a licensee were to wait until the ERO assignment process was completed before crediting the DEP performance indicator for an ERO-member-in-training, then the opportunity could be counted in a reporting period other than the one in which the performance enhancing experience occurred. At North Anna, a performance enhancing experience was provided to new ERO member before they assumed their ERO position. The ERO member assumed their ERO position one day later; however, that day spanned reporting periods.

Question: How and when should DEP PI opportunities for ERO-members-in-training be counted?

Response PI opportunities and participation credit should not be counted for ERO-members-in-training. DEP opportunities are only counted for plant staff members who are currently **assigned to fill a key position** on the ERO.

Background:

NEI 99-02, page 79, Line 31 states The percentage of drill, exercise, and actual opportunities that were performed timely and accurately by **Key Positions**, as defined in the ERO Drill Participation indicator,.

NEI 99-02, page 86, Line 11 states, ERO members **assigned to fill Key Positions**.

Discussion:

The participation PI tracks Key ERO members **assigned** to the ERO. The key word here is **assigned**. Trainees are not assigned to the ERO and therefore DEP opportunities or participation does not count.

Data reporting may be affected in accordance with this FAQ at some plants. There is no need to modify past record keeping practices based on this FAQ. Record keeping practices should only be modified for practices conducted after this FAQ is approved.

Note: This FAQ received final approval during the May 17, 2006 public meeting. The effective date of this FAQ will be discussed at the June 14, 2006 public meeting. At this meeting it will be determined whether the FAQ applies to reporting beginning with 2Q2006 or beginning with 3Q2006.

Emergency Preparedness

EP01-EP02 Emergency Preparedness

ID 233

Posting Date 10/31/2000

Question A licensee used same scenario for each of the three response teams. The drills contributed to DEP and ERO statistics. Repetitive use of the scenario has the potential to skew the PI success rate if scenario confidentiality is not maintained. There was no indication that drill participants were intentionally informing other teams about the scenario, but discussions of the drill could inadvertently reveal facts about the scenario.
Is it permissible to repeat the use of scenarios in drills that contribute to DEP and/or ERO statistics?

Response Yes, the licensee need not develop new scenarios for each drill or each team. However, it is expected that the licensee will maintain a reasonable level of confidentiality so as to ensure the drill is a proficiency-enhancing evolution. A reasonable level of confidentiality means that some scenario information could be inadvertently revealed and the drill remains a valid proficiency-enhancing evolution. It is expected that the licensee will remove from the drill performance statistics any opportunities considered to be compromised.
There are many processes for the maintenance of scenario confidentiality that are generally successful. Examples may include the following:

* Confidentiality statements on the signed attendance sheets,

* Spoken admonitions by drill controllers.

Examples of practices that may challenge scenario confidentiality include:

* Drill controllers or evaluators or mentors, who have scenario knowledge becoming participants in subsequent uses of the same scenarios,

* Use of scenario reviewers as participants.

Emergency Preparedness

EP02 ERO Dril Participation

ID 414

Posting Date 09/14/2006

Question Going forward, this FAQ applies to Security Based EP Drills and Exercises as defined in NRC Bulleting 2005-02, "Emergency Preparedness and Response Actions for Security-Based Events." This FAQ may also be applied to the Callaway Security Based EP Drill conducted on March 1, 2006 since this drill was conducted as a pilot in response to the bulletin that included the activation of emergency response organization and facilities and met the requirements of this FAQ response.

Question Section

Can ERO members assigned to fill Key Positions in the TSC and EOF be granted credit for ERO Participation for a Security related Drill or Exercise as defined in NRC Bulletin 2005-02, "Emergency Preparedness and Response Actions for Security-Based Events", when no DEP opportunity exist for these facilities.

Response Yes, ERO members assigned to fill Key Positions in the TSC and EOF can be granted credit for ERO Participation for a Security related Drill or Exercise, as long as the drill is performance enhancing and:

• If an individual participates in more than one Security-related Drill/Exercise in a three year period, only one
of the Security–related Drills/Exercise can be credited.

• A station cannot run more than one credited Security-related Drill/Exercise in any consecutive 4 quarter period.

The Senior Manager - TSC, Senior Manager - EOF, Key Operations Support – TSC, Key Radiological Controls - TSC and Key Protective Measures - EOF may be granted participation credit as long as the Key Positions are
observed evaluating the need to upgrade to the next higher classification level and/or evaluating the need to change
protective action recommendations. This evaluation may take the form of discussing and establishing the parameters that
would require a change in Classification or PAR.

Key TSC Communicator and Key EOF Communicator may be granted participation credit as long as the Key Position
performs at a minimum one offsite (state /local) update notification.

Objective evidence shall be documented to demonstrate the above requirements were met. Examples of objective evidence are player logs, evaluator or controller notes, dose calculations, worksheets and offsite (state/local)
notification paperwork.

Background Information

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>The Clarifying Notes section (revision 4, page 45, starting at sentence 29) states that, "The license may designate
drills as not contributing to DEP and, if the drill provides a performance enhancing experience as described herein, those

Key Positions that do not involve classification, notification or PARs may be given credit for ERO Drill Participation". The Clarifying Notes section (revision 4, page 46, starting at sentence 25) also states, "ERO members may receive credit for the drill if their participation is a meaningful opportunity to gain proficiency in their ERO function."

In order for a security drill or exercise to be considered a performance enhancing experience/meaningful opportunity to gain proficiency for key personnel the drill or exercise needs to demonstrate major elements of the emergency plan and key team skills for mitigating the security based event and will require activation of all of the licensee's emergency response facilities where participation credit is provided for Key Positions (Technical Support Center (TSC), Operations Support Center (OSC), and the Emergency Operations Facility (EOF)) . These facilities are activated after aircraft impact or an attack without warning (post perpetrator neutralization) to the protected area. Examples of skills used by members of the ERO for mitigating security based events post aircraft impact or attack that demonstrate major elements of the emergency plan are:

• Exercising management and coordination of the overall emergency response,

• Interfacing with on site Security personnel,

• Assessment of classification, notifications and / or PARs (initial classification, notification or PARs will only be demonstrated by the Control Room. However it is expected that the TSC and EOF will be involved with performing update notifications and revalidation of current classification and PARs as the event unfolds. This continuing revalidation of classification and PARs and subsequent communications with offsite authorities will provide practice in these elements during Security Drills) Objective evidence will need to be maintained as discussed in the answer section of this FAQ.

• Accounting for all individuals on site, which includes direction of search and rescue activities, mass casualty response and coordination of the medical response,

• Coordination of onsite fire response and coordination of offsite fire resources,

• Approval of public information,

• Field team verification of no radioactive release,

• Interfacing with Law enforcement agencies in response to a crime scene investigation,

• Repair and corrective actions of plant equipment damaged in the security event which may include allocation of limited resources and authorization of high radiation exposure work in excess of part 20 limits,

• Simulated interaction or actual interaction with NRC regional and national EOCs.

Because Security Drills are performance enhancing experiences, licenses may therefore designate a Security

Drill or Exercise as not contributing to DEP in the TSC and EOF and still give participation credit for all ERO members
assigned to fill Key Positions in the TSC and EOF.

Proposed wording for inclusion in the next revision to NEI 99-02:

Revise NEI 99-02 to add the following paragraph to the Clarifying Notes on page 45 after the second paragraph which ends on line 36:

Credit can be granted to Key Positions for ERO Participation for a Security related Drill or Exercise as long as the Key Positions are observed evaluating the need to upgrade to the next higher classification level and/or evaluating the need to change protective action recommendations. Key TSC Communicator and Key EOF Communicator may be granted participation credit as long as the Key Position performs a minimum of one offsite (state/local) update notification.
If an individual participate in more than one Security-related Drill/Exercise in a three year period, only one of the Security-related Drills/Exercise can be credited. A station cannot run more than one credited Security-related Drill/Exercise in any consecutive 4 quarter period. Objective evidence shall be documented to demonstrate the above requirements were met.

ID 377

Posting Date 03/17/2005

Question NEI 99-02 Rev 2 ERO Participation PI defines the numerator and denominator of the calculation as based on Key ERO Members. The key position list (on page 89 and 90) was originally created from NUREG 0696 key functions that involved actions associated with the risk significant planning standards (classification, notification, PARs, and assessment), with the addition of the Key OSC Operations Manager included from a mitigation perspective

When a single individual is assigned in more than one 'key position' that individual must be counted for each key position (page 91 lines 4-7 of NEI 99-02).

Guidance is not provided in the case where more than one key position is performed by a single member of the ERO in a single drill/exercise. For example, the communicator is defined in NEI 99-02 as the key position that fills out the notification form, seeks approval and usually communicates the information to off site agencies (these duties may vary from site to site based on site procedures).

Assigning a single member to multiple Key Positions and then only counting the performance for one Key Position could mask the ability or proficiency of the remaining Key Positions. The concern is that an ERO member having multiple Key Positions may never have a performance enhancing experience for all of them, yet credit for participation will be given when any one of the multiple Key Positions is performed.

When the communicator key position is performed by an ERO member who is also assigned another key position (e.g., the Shift Manager (Emergency Director)), should participation be counted for two key positions or for one key position?

Response Participation by a single member of the ERO performing multiple key positions should be counted for each key position performed. For the situation described, two key positions should be counted.

ERO participation should be counted for each key position, even when multiple key positions are assigned to the same ERO member. In the case where a utility has assigned two or more key positions to a single ERO member, each key position must be counted in the denominator for each ERO member and credit given in the numerator when the ERO member performs each key position

Assigned as used in this FAQ applies to those ERO personnel filling key positions listed on the licensee duty roster on the last day of the reporting period (quarter). Note, however, the exception on page 92 line 1-2 of NEI 99-02, that states, All individuals qualified to fill the Control Room Shift Manager/Emergency Director position that actually might fill the position should be included in this indicator.

This FAQ will become effective 4/1/05 and applies to data submitted for the second quarter 2005 and going forward

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ID 371

Posting Date 10/13/2004

Question This FAQ has been withdrawn and replaced by FAQ 377

Response

ID 327

Posting Date 12/12/2002

Question NEI 99-02 states in the clarifying notes for the ERO PI, "When the functions of key ERO members include classification, notification, or PAR development opportunities, the success rate of these opportunities must contribute to Drill/Exercise Performance (DEP) statistics for participation of those key ERO members to contribute to ERO Drill Participation." Must the key ERO members individually perform an opportunity of classification, notification, or PAR development in order to receive ERO Drill Participation credit?

Response No. The evaluation of the DEP opportunities is a crew evaluation for the entire Emergency Response Organization. Key ERO members may receive credit for the drill if their participation is a meaningful opportunity to gain proficiency in their ERO function.

ID 126

Posting Date 04/01/2000

Question Is it appropriate to track the Shift Supervisor's drill participation to meet the "shift communicator function" described in NEI 99-02?

Response Yes, if the Shift Supervisor fills the Shift Communicator function.

ID 85

Posting Date 02/15/2000

Question In NEI 99-02, under Definition of Terms (Pg. 81), Control Room Shift Manager (Emergency Director) is identified as a key ERO member. We currently only include those Shift Managers who have been permanently assigned to an operating crew. Operations Department personnel who may be qualified as Shift Manager and may fill this role in relief (vacations, training, etc.) or periodically to maintain qualifications are not currently considered under this indicator.

Should all individuals qualified to fill the Shift Manager position be considered under this indicator, regardless of whether they are assigned to a specific crew on a continuing basis?

Response Yes. All individuals qualified to fill the Shift Manager position who actually might fill the position should be included in this indicator.

ID 54

Posting Date 11/11/1999

Question Many plants have staff personnel who hold SRO licenses. These individuals only stand watch in the control room as necessary to retain an active license. Is it necessary to track these individuals under the ERO PI?

Response Yes, because they could perform as the Shift Manager in an actual event. However, an informal survey of EP programs indicated that these personnel routinely participate in drills, either as key ERO members, or as evaluators. This being the case, the burden for licensees should be minimal.

ID 53

Posting Date 11/11/1999

Question Can a single person fill multiple key functions?

Response Yes, if that is in accordance with the approved emergency plan.

ID 52

Posting Date 11/11/1999

Question If a person is not yet qualified to fill a certain key ERO position but participated in a drill in that position for qualification purposes, would that participation count?

Response This could be left to the licensees judgment and verified by inspection. Where the participation in the drill/exercise is a proficiency?enhancing experience it could be counted. This would mean that the individual is familiar with the position and able to perform it but perhaps the lack of qualification is merely due to the timing of required classroom training. However, he should not formally be on the duty roster until fully qualified. When that occurs, the drill/exercise participation date could be used in reporting ERO.

ID 51

Posting Date 11/11/1999

Question What would happen if an ERO member fails to correctly perform its duties, for example invoked a wrong classification - does this count as participation?

Response Yes, the participation would count and the missed opportunity for proper classification would be reflected in the DEP indicator. It might be expected that the individual will receive feed back on performance to ensure proficiency, but as long as the DEP PI is in the licensee response band, this problem is left to the licensee to correct.

ID 50

Posting Date 11/11/1999

Question When a key ERO member is added to the organization or changes from one key ERO position to a different key ERO position between drills, is there a grace period for having him or her participate in drills?

Response No, there is no grace period. However, if the individuals new position is similar to the old one, the last drill/exercise participation may count. If the new position is unrelated to the old position then the previous participation would not count.

ID 49

Posting Date 11/11/1999

Question Is there a minimum number of ERO members.

Response The NRCs requirements for minimum staffing at nuclear power plants are given in NUREG 0654 Table B-1. The site Emergency Plan commits to a method to meet these requirements and that is the minimum ERO. The PI measures the participation of a segment of the ERO (key ERO members as defined in NEI 9902) in drills/exercises (or other appropriate proficiency enhancing experiences).

ID 48

Posting Date 11/11/1999

Question Is participating in a performance-training environment once every two years the new minimum expectation?

Response There is no NRC requirement associated with the frequency of ERO personnel participation in drills or exercises. However, the threshold for this PI is that 80% of the key ERO members participate on a 2 year frequency for a plant to be considered as operating in the licensee response band (green).

ID 47

Posting Date 11/11/1999

Question Could a licensee have key ERO members cycle through a position for an exercise or drill and allow them to be counted for this indicator?

Response The licensee can have key ERO members cycle through a position for an exercise or drill and allow them to be counted for this indicator as long as the licensee can justify that their participation is a proficiency-enhancing experience.

ID 46

Posting Date 11/11/1999

Question How does the program handle the case where the number of key ERO members is different at the end of the evaluation period than at the beginning of it?

Response This indicator is calculated based on the number of key ERO members at the end of the quarter.

ID 45

Posting Date 11/11/1999

Question How does the program handle the case where someone shifts ERO position during the drill or exercise?

Response The persons participation may be counted for each position as long as the participation constitutes a proficiency-enhancing experience. The licensee will make this determination. The NRC will verify the adequacy of the licensees determination as part of its performance indicator verification inspection.

ID 44

Posting Date 11/11/1999

Question How does the program address a person who is qualified in more than one position and listed on the ERO roster for all positions that he or she is qualified to fill?

Response The licensee has to evaluate if the different positions being filled by the individual require different knowledge and skills to perform. If they do then it is expected that the person be counted in the denominator for each position and in the numerator only for drill/exercise participation that addresses each position. Where the skill set is similar, a single drill or exercise might be counted as participation in both positions. Examples of similar skill sets may include: Emergency Managers and their assistants or technical support staff; Communicators in different facilities; Health Physics personnel in different facilities. However, important differences in duties must be considered, e.g., TSC HP positions may involve onsite radiation safety where as EOF HP positions would not, and the EOF HP positions may involve dose projection duties where as the TSC HP positions may not.

Another option would be to evaluate the need to maintain this person qualified to fill multiple positions if the depth of positions being filled is more than four, then dual qualification of the individual may not be necessary, depending on the design of the duty roster and call out system.

Emergency Preparedness

EP03 Alert and Notification System

ID 396

Posting Date 05/19/2005

Question May siren testing conducted at redundant control stations, such as county EOCs, that are staffed during an emergency by an individual capable of activating the sirens be credited in the ANS PI?

Response Yes. If the redundant control station is in an approved facility as documented in the FEMA ANS design report.

ID 378

Posting Date 03/17/2005

Question Catawba Nuclear Station has 89 sirens in their 10-mile EPZ; 68 of these are located in York County. Duke Power's siren testing program includes a full cycle test for performance indicator purposes once each calendar quarter. On Tuesday, September 7, 2004, York County sounded the sirens in their county's portion of the EPZ to alert the public of the need to take protective actions for a Tornado Warning. Catawba is uncertain whether to include the results of the actual activation in their ANS PI statistics. The definition in NEI 99-02 does not address actual siren activations. In contrast, the Drill/Exercise Performance (DEP) Indicator requires that actual events be included in the PI. Should the performance during the actual siren activation be included in the Alert and Notification System (ANS) Performance Indicator Data?

Response For this instance, Catawba may include the results of the September 7, 2004 actual siren activations in their ANS PI data. However, for all future instances, no actual siren activation data results shall be included in licensees' ANS PI data.

ID 376

Posting Date 11/18/2004

Question This FAQ has been withdrawn and replaced by FAQ 378.

Response

ID 375

Posting Date 11/18/2004

Question If a licensee makes a change in ANS testing methodology, when can that change be used in the ANS PI calculation?

Response Any change in test methodology shall be reported as part of the ANS Reliability Performance Indicator effective the start of the next quarterly reporting period.

A licensee may change ANS test methodology at any time consistent with regulatory guidance. For the purposes of the Performance Indicator, only the testing methodology in effect on the first day of the quarter shall be used for that reporting period. Neither successes nor failures beyond the testing methodology at the beginning of the quarter will be counted in the PI. However, performance during actual siren activations that utilize the nuclear power plants ANS activation system shall be included in the PI data.

NEI 99-02 requires that the periodic tests be used in developing the Performance Indicator. Pg 94, lines 12-13, states that: Periodic tests are the regularly scheduled tests... Therefore, a reporting period (quarter) starts with a sequence of regularly scheduled tests for that quarter. If a licensee determines that testing methodology should be changed, the plan/procedure directing the periodic tests should be revised and screened in accordance with the licensees change. If the change in ANS test methodology is considered to be a significant change per FEMA requirements, the change is required to have FEMA approval prior to implementation. This FAQ will take effect 1/1/05 and apply to siren testing after 1/1/05.

ID 372

Posting Date 10/13/2004

Question Pilgrim has 112 sirens which are normally scheduled to be tested for performance indicator purposes once each calendar month (e.g., once during the month of September). This was reflected in procedure as a requirement to test all of the sirens monthly. The person scheduling the testing of the sirens incorrectly interpreted the procedures monthly frequency consistent with other monthly tests as allowing a 25% grace period for scheduling flexibility. As a result, 29 of the siren tests normally scheduled to be performed in September were scheduled to be performed during the beginning of October.

On October 1 the status of the siren testing was discussed with other members of the plant staff who understood that the intent of the monthly requirement was once per calendar month and that no grace period applied. Immediate actions were taken including performing the remaining 29 tests on an accelerated basis (all satisfactory tested by October 3) and entering the item in the corrective action program.

All of the 29 sirens passed the testing performed during the first 3 days of October. The testing was not delayed due to the unavailability or suspected unavailability of the sirens. The reason for the late testing of the equipment was purely an administrative error and not siren functionality related.

For plants where siren tests are initiated by the utility, if a scheduled test(s) was not performed due to an administrative issue but the untested siren(s) was not out-of-service for maintenance or repair and was believed to be capable of operation if activated, should the missed tests be considered non-opportunities or failures for performance indicator reporting purposes?

Response Regularly scheduled tests missed for reasons other than siren unavailability (e.g., out of service for planned maintenance or repair) should be considered non-opportunities. The failure to perform a regularly scheduled test should be entered in the plants corrective action program and annotated in the comment field on the quarterly data submittal. The failure to perform regularly scheduled tests may be reviewed as part of the baseline inspection process.

ID 358

Posting Date 02/19/2004

Question Can the licensee modify the ANS testing methodology when calculating the site value for this indicator?

Response Yes. Page 95 line 19-23 of NEI 99-02 will be modified as follows:
Changes to the activation and/or testing methodology 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.
Note: If prior to this FAQ response, a plant changed their testing methodology, it is not necessary to recalculate their past PI data from the time of the change. However, those plants still need to update the affected PI data report by noting the change in the comment section.

ID 246

Posting Date 01/10/2001

Question If a siren is out of service during a planned overhaul or upgrade project does this need to count as both a siren test and a siren failure?

Response Discussion:The ANS PI measures the percentage of ANS sirens that are capable of performing their safety function, as measured by periodic siren testing in the previous four quarters. NEI 99-02 states, "If a siren is out of service for maintenance or is inoperable at the time a regularly scheduled test is conducted, then it counts as both a siren test and a siren failure."
ANS systems are aging and many sites are considering and/or performing siren overhaul or system upgrade projects. The ANS PI threshold may impact project planning in an unintended manner. It is not the intent to create a disincentive for performing ANS overhaul or upgrade projects.

When sirens are out of service for such projects, it is expected that the utility arrange for back-up public alerting in the appropriate siren coverage areas. This support is typically provided by local offsite agencies and often involves route alerting. The acceptable time frame for allowing a siren to remain out of service for system upgrade or preventive maintenance should be coordinated with the cognizant offsite agencies. Based on the impact to local agencies and the ANS functionality, outage time frames should be minimized and specified in ANS Upgrade/Overhaul Project Documents. When the time frame is identified in advance as part of an upgrade or overhaul project, and back-up public alerting coverage agreed to by offsite agencies, regularly scheduled tests during the siren outage may be excluded from the ANS PI statistics. Deviations from the advance outage schedule would constitute unplanned siren reliability and siren-test failures outside of the preplanned outage window would be included in the PI. This modification of the PI is not intended for preventative or corrective maintenance, i.e., siren-test failures due to preventative or corrective maintenance must be included in the ANS PI.

Response:No, if the ANS overhaul or upgrade project meets certain requirements as delineated in the discussion section of this FAQ. However, the exclusion is not intended for preventative or corrective maintenance.

ID 232

Posting Date 10/31/2000

Question Siren systems may be designed with equipment redundancy or feedback capability. It may be possible for sirens to be activated from multiple control stations. Feedback systems may indicate siren activation status, allowing additional activation efforts for some sirens.
1) A siren system has two normally attended control stations from which the system may be activated. If a siren test from one station is unsuccessful can a test performed from the second station be considered as a part of the regularly scheduled test?

2) A siren test technician sent multiple activation signals to a siren that initially appeared not to respond. The siren responded. Can the multiple signals be considered as the regularly scheduled test and hence a success?

Response 1) Yes, if the use of redundant control stations is in approved procedures and is part of the actual system activation process. A failure of both systems would only be considered one failure, where as the success of either system would be considered a success.
If the redundant control station is not normally attended, requires set up or initialization, it may not be considered as part of the regularly scheduled test. Specifically, if the station is only made ready for the purpose of siren tests it should not be considered as part of the regularly scheduled test.

2) Yes, if the use of multiple signals is in approved procedures and part of the actual system activation process. However, the use of multiple activation signals to achieve successful siren tests may not include any activities outside the regularly scheduled test, such as troubleshooting, post maintenance testing or activation signals sent after the initial activation process has ended.

ID 229

Posting Date 10/31/2000

Question During a scheduled siren test, a siren (or sirens) fail or cannot be verified to have responded to the initial test. A subsequent test is done to troubleshoot the problem.
1) Should the troubleshooting test(s) be counted as siren test opportunities?

2) Should failures during troubleshooting be considered failures?

3) Should post maintenance testing or system retests after maintenance be counted as opportunities?

4) If subsequent testing shows the siren to be operable (verified by telemetry or simultaneous local verification) without any corrective action having been performed, can the initial test be considered a success?

Response 1) No. These tests are not regularly scheduled tests because they are only conducted if there are siren failures.
2) No. These tests are not regularly scheduled tests because they are only conducted if there are siren failures.

3) No. These tests are not regularly scheduled tests because they are only conducted if there are siren failures.

4) Yes, but only if it is reasonably verified that the failure was in the testing equipment and not the siren control equipment, i.e., the siren would have sounded when called upon, even though the testing equipment would not have indicated the sounding. In the process of verifying that the failure is only with testing equipment, problems such as radio signal transmission weakness or intermittent signal interference should be eliminated as the cause. Maintenance records should be complete enough to support such determinations and validation during NRC inspection.

ID 200

Posting Date 07/12/2000

Question Appendix D Grand Gulf

Of the 43 sirens associated with our Alert Notification System, two of the sirens are located in flood plain areas. During periods of high river water, the areas associated with these sirens are inaccessible to personnel and are uninhabitable. During periods of high water, the electrical power to the entire area and the sirens is turned off. The frequency and duration of this occurrence varies based upon river conditions but has occurred every year for the past five years and lasts an average of two months on each occasion.

Assuming the sirens located in the flood plain areas are operable prior to the flooded and uninhabitable conditions, would these sirens be required to be included in the performance indicator during flooded conditions?

Response If sirens are not available for operation due to high flood water conditions and the area is deemed inaccessible and uninhabitable by State and/or Local agencies, the siren(s) in question will not be counted in the numerator or denominator of the Performance Indicator for that testing period.

ID 174

Posting Date 05/02/2000

Question For plants where scheduled monthly siren tests are initiated by local or state governments, if a scheduled test is not performed either (intentionally or accidentally), is this considered a failure?

Response No. For purposes of the NRC PI, missed tests should be considered non-opportunities.

ID 124

Posting Date 04/01/2000

Question The EP cornerstone, PI Alert and Notification System Reliability reports tests performed of off-site sirens to determine the systems reliability. Indian Point 3 is on the same site as Indian Point 2 but owned and operated by the New York Power Authority. IP3 uses the offsite sirens to meet its EP requirements. However, the sirens are owned, operated, and tested by Con Edison, owners of Indian Point 2. IP3 has an administrative agreement on use of the sirens by IP2 for IP3. Con Edison (IP2) notifies NYPA (IP3) by letter on the results of their siren testing and the status of their equipment. Question; does Indian Point 3 have to report data for this PI (EP03) since NYPA does not perform the testing nor control the sirens, and only reports what Indian Point 2 reports ? (i.e., duplicate what IP2 reports)

Response Yes. The responsibility to notify the public is held mutually by each licensee located on the same site with the same EPZ. Therefore, each licensee should provide alert and notification performance data event if it is repetitive due to a mutually shared site.

ID 123

Posting Date 04/01/2000

Question Some of the sirens included in the alert and notification performance indicator have the capability to be sounded from a remote location using a siren encoder. A quarterly 'growl' test is conducted at each siren site. Encoder testing is performed separately. Does the malfunction of a remote siren encoder constitute a failure if the siren is functional by local actuation?

Response Testing mechanisms used to comply with FEMA reporting methodology should be used to report performance indicator statistics. Failures occurring during this testing would count toward the performance indicator.

ID 122

Posting Date 04/01/2000

Question In defining the total number of siren-tests in the previous 4 quarters should those sirens not tested because they were either out of service or undergoing maintenance at the time of the test be included in the denominator of total number of siren-tests? Should this number simply be the total number of sirens times the number of tests or the actual number of sirens tested? In our case, all sirens are always tested (except those that cannot be physically tested due to outage or maintenance) as part of each test.

Response The total number of sirens should be reported in the denominator.

ID 56

Posting Date 11/11/1999

Question If some sirens were unavailable due to storm damage, would the missed siren-tests prior to the sirens being returned to service be considered failures?

Response Yes, the missed siren-tests would be considered failures. However, if the licensee can repair the damaged sirens prior to the test, then the siren tests would be considered successful.

ID 55

Posting Date 11/11/1999

Question This indicator only monitors siren reliability. Why arent other EP equipment and facilities monitored?

Response Ensuring public health and safety is the goal of the NRC oversight program. Analysis of the EP function shows that the ANS is a risk-significant system in ensuring licensee ability to protect the public health and safety. There is other important equipment and facilities, but ensuring the readiness of these is in the licensee response band. ERO measures the participation of key emergency response organization members in drills/exercises and assumes, in part, that such participation is a good method to identify equipment and facility problems. DEP measures timely and accurate classifications, notifications and PARs, which can only be performed if communication and assessment equipment are functioning. It is expected that licensee corrective action programs will address equipment readiness problems that are identified during drills. These programs are a focus of the NRC inspection program.

Occupational Radiation Safety

OR01 Occupational Exposure Control Effectiveness

ID 369

Posting Date 09/16/2004

Question A worker entered a Technical Specification High Radiation Area (> 1R/hr) with all requirements of the job (training, briefings, dosimetry, ALARA Plan and RWP requirements, electronic dosimetry, etc.). The worker did not perform the RWP process auto-sign-in on the RWP, which would have electronically checked the workers 700 mrem administrative RWP buffer. Not performing this auto-sign-in process did not violate the primary means of controlling access and did not invalidate the RWP for the job. The RWP stated that 700 mrem dose availability was required prior to entry. This administrative dose buffer is an additional defense-in-depth, licensee-initiated control to protect against exceeding the licensees system of dose control and is not utilized to control dose. The workers actual dose did not exceed the electronic dosimeter set point and the minimum administrative control guideline. The dose availability of the worker is defined as the difference between the site-specific administrative control level of 2000 mrem (significantly below Federal Limits) and the workers current accumulated dose for the year

An ALARA Plan and RWP controlled the work activity. The individual used teledosimetry with predetermined alarm setpoints for the job, which transmitted dose and dose rate information during the entry. Video surveillance was utilized by radiation protection technicians and in compliance with 10CFR20.1601(b) during the entry into the >1R/hr area. Specific authorization was given by the remote monitoring station technician to enter into the area. The worker had the training and respiratory protection qualifications required by the RWP, multiple TLDs had been issued, the required RWP was obtained and signed, and briefings were attended. The RWP entry was accomplished within pre-determined stay-time limitations, as discussed in the worker briefing. The electronic entry time was entered after the worker had exited the area. There was no over exposure or unintended dose for this worker. The work was completed within the maximum projected dose for the activity. Technical Specification requirements for control of entry into the high radiation area were met and worker dose was controlled since the worker was authorized and had obtained the RWP for the job.

The primary means of control of occupational dose exposure include pre-determined stay-time limitations and alarming dosimetry set below expected job levels. The administrative control level is an additional exposure control mechanism. The licensees administrative control level is conservatively established at 2 rem, or 40% of the Federal dose limit, to provide a substantial margin to prevent personnel from exceeding the Federal dose limit of 5 rem and to help ensure equitable distribution of dose among workers with similar jobs. The individuals annual dose was well below 2 rem and the administrative control level had not been raised above 2 rem prior to the worker obtaining a TLD. If needed, additional and higher levels of managerial review and authorization are required for higher dose control levels. Increasing levels of management review and approvals are required to exceed the administrative control level of 2000 mrem (i.e., to 3000 mrem requires written approval by the Radiation Protection Manager and the work group supervisor, to 4000 mrem requires written approval by the Radiation Protection Manager, work group supervisor, and Plant Manager, to 5000 mrem requires written approval by the Site Vice President). The administrative dose buffer is in addition to the Technical Specification requirements for an RWP and therefore not material to the Technical Specification requirements for control of occupational dose.

As it is stated in NEI 99-02, "this PI does not include nonconformance with licensee-initiated controls that are beyond what is required by technical specifications and the comparable provisions in 10CFR Part 20. The check of dose availability is a licensee-initiated administrative control that is beyond what is required by technical specifications, comparable provisions in 10CFR20, or Regulatory Guide 8.38. Does failure of the worker to meet the internal administrative control guideline for dose available as specified by the RWP for the job activity count as a PI occurrence?

Response Yes this event would be a reportable PI occurrence. The above clearly describes a nonconformance with an RWP procedural requirement that resulted in a loss of control of access to the Tech. Spec. High Radiation Area. Had the RWP procedure been adhered to, this individual would not have been allowed to enter without further approval.

ID 368

Posting Date 09/16/2004

Question The definition of the Occupational Exposure Control Effectiveness performance indicator refers to measures that provide assurance that inadvertent entry into the technical specification high radiation areas by unauthorized personnel will be prevented (page 98, NEI 99-02, Revision 2). In the context of applying the performance indicator definition in evaluating physical barriers to control access to technical specification high radiation areas, what is meant by inadvertent entry?

Response In reference to application of the performance indicator definition in evaluating physical barriers, the term inadvertent entry means that the physical barrier can not be easily circumvented (i.e., an individual who incorrectly assumes, for whatever reason, that he or she is authorized to enter the area, is unlikely to disregard, and circumvent, the barrier). The barriers used to control access to technical specification high radiation areas should provide reasonable assurance that they secure the area against unauthorized access.

ID 364

Posting Date 04/22/2004

Question 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 areas 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 workers entry. The same area had been occupied numerous times after the last survey, before filling, with no problems. Should this be counted as a performance indicator event?

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?

Response This is a reportable Performance Indicator (PI) occurrence. The statement in this question that the "...dose rates had been confirmed by past experience..." is incorrect. As described in this example, the dose rates in this area were assumed, not confirmed by a (pre work or routine) survey. This is the heart of the performance deficiency. Placing direct (and, or remote) reading dosimeters on workers is not a substitute for adequate surveys as required by Part 20. This example is not a case where the non-conformance was reasonably unanticipated. This is an example of a lack of vigilance by the radiation protection program. The reactor refueling cavity drain and fill system clearly had the potential for high dose rates, and an adequate pre work survey would have uncovered the radiological condition.

ID 362

Posting Date 04/22/2004

Question Two job-coverage Radiation Protection technicians were performing a job turnover at the entrance to a Steam Generator Bay. At the time the Steam Generator Bay was posted and locked as a Locked High Radiation Area. During the turn over process the RP Technicians entered into the posted region of the Locked High Radiation Area. When they entered a few feet past the doorway the door was left open and the radiological posting was left down. However, the Radiation Protection technicians provided direct surveillance capable of preventing unauthorized entry in the high radiation area. The RP Technicians were cognizant of the need to control access to the area and did so throughout the turnover.

Is this event considered performance indicator occurrence?

Response This is not considered a performance indicator occurrence because the Radiation Protection technicians maintained positive control over access to the area.

ID 346

Posting Date 05/01/2003

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?

Response Questions 342, 344, 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.

ID 345

Posting Date 05/01/2003

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?

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.

ID 344

Posting Date 05/01/2003

Question 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.

Response Questions 342, 346 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.

ID 342

Posting Date 05/01/2003

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 technicians 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?

Response Questions 344, 346 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.

ID 341

Posting Date 05/01/2003

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 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 wasnt 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.

ID 333

Posting Date 12/12/2002

Question A radiation worker entered the containment during power operation. At that time, the containment was a posted locked high radiation area with dose rates > 1,000 mrem per hour. Prior to entering the containment, the worker in error logged onto the wrong radiation work permit (RWP), which did not allow access to a locked high radiation area. In fact, the individual had been approved for entry into the containment, conformed with the controls specified in the correct RWP, and met all other requirements for entry, including being aware of the radiological conditions in the area being accessed, proper electronic dosimeter alarm set points, continuous coverage by Health Physics, etc. There was no "unintended exposure." The single error was related to logging onto the wrong RWP. Does this type of error count against the PI for Technical Specification High Radiation Area (>1,000 mrem per hour) occurrences?

Response No, as described, this would not count against the PI. The performance basis of the PI was met because the worker was properly informed about radiological conditions and the proper radiological controls were implemented. The workers error in logging in on the wrong RWP is an administrative issue that is not considered a deficiency with regard to the performance basis of the PI.

ID 332

Posting Date 12/12/2002

Question During a review of electronic dosimeter (ED) /TLD discrepancies of eddy current workers, it was noted that for two of the workers, the electronic dosimeter under-reported the dose compared to the recorded official dose by TLD. An investigation revealed the following:

- Multiple TLDs were placed on each worker for work on the platform. Locations included the head, chest, upper left and upper right arms.
- A single electronic dosimeter was placed on either the right or left upper arm, depending on which arm the worker was most likely to use when manipulating the robot inside the man way.
- A "jump ticket", containing the authorized dose was used for each entry.
- The radiation protection technicians used telemetry connected to the ED to control exposures. Video and voice communications were also part of the remote monitoring system.
- Estimated dose for each entry was recorded, based on the electronic dosimeter. The same TLDs were used for multiple entries. As a result, a direct comparison of TLDs to electronic dosimeter readings on a per entry basis could not be performed.
- Estimated (ED) doses for the two workers, with the highest official doses, were low by 39% and 44%.
- One of the workers with an authorized dose of 300 mrem for an entry received an estimated (ED) dose of 275 mrem. Using a ratio of TLD to ED dose of either his total exposures or the other worker's total exposures for the job, a corrected dose in the range of 450 to 460 mrem could be calculated for the single entry.
- Estimated (ED) dose for 12 of 15 workers was low, when compared to the TLD at location of highest recorded exposure.

Does this constitute an unintended exposure occurrence in the Occupational Radiation Safety Cornerstone as described in NEI 99-02?

Response No, assuming that a proper pre-job survey and evaluation was performed. Although, in retrospect, it was determined that the estimating device was not placed in the location of highest exposure, it was placed in the area anticipated to receive the highest exposure and used appropriately to keep exposure below the authorized dose per entry. Record dose was properly assigned using the results of the TLD placed at the location of highest exposure.

ID 331

Posting Date 12/12/2002

Question The scope of a job changed such that completion of the job would involve additional collective dose with regard to the original estimate. From the time that the work activities deviated from the original plan to the time that ALARA staff documented a revision to the plan and a new collective dose estimate, an individual received more than 100 mrem TEDE from external dose while continuing to work on this job. During this timeframe, the worker was performing activities outside of the original work plan. The time period from deviation from the original plan to documentation of the revised plan and dose estimate for the job is approximately one day. The licensee defines an "unintended exposure event" for TEDE in their procedures as a situation in which a worker receives 100 mrem or more above the electronic dosimeter dose alarm set point for a given RCA entry. On this job, all of the workers maintained their individual dose below the electronic dosimeter dose alarm for every RCA entry performed. Is this situation an "unintended exposure event"?

Response No, the described circumstances appear to represent an ALARA issue, not a performance deficiency with regard to the scope of the Occupational Exposure Control Effectiveness PI. The purpose of the PI is to address the Occupational Radiation Safety Cornerstone objective of "keep[ing] occupational dose to individual workers below the limits specified in 10 CFR Part 20 Subpart C." During development of the Performance Indicators, it was decided not to pursue a PI for the ALARA-based objective in the Occupational Radiation Safety Cornerstone. That objective is met through the ALARA inspection module. Further, with regard to "Unintended Exposure", the PI states that it is "incumbent on the licensee to specify the method(s) being used to administratively control dose." In this case, the licensee has apparently selected the use of electronic dosimeter alarm set points as the method for administratively controlling external dose, in which case the applicable criterion for the PI would be if the external dose exceeded the alarm set point by 100 mrem or more.

ID 321

Posting Date 10/31/2002

Question While in a high radiation area (HRA) removing scaffold, workers inadvertently dislodged lead shielding around a hot spot flush rig and created conditions that required posting a locked HRA (dose rates in excess of 1 rem per hour). Several minutes later when they moved to a location closer to the hot spot, the three scaffold workers received dose rate alarms. Upon receiving the alarms, they immediately left the area and the alarms cleared. After reading their dosimeters and verifying that they had not received any unexpected dose, they discussed the alarms with their supervisor and concluded that the momentary alarm was not unexpected since general area dose rates in the HRA could have caused the alarms. When the three workers attempted to log out of the RCA at the access control point, Health Physics (HP) discovered that all three individuals received a "Dose Rate" alarm on their electronic dosimeters. Independent from the ensuing exposure investigation, and approximately within the same time period (within minutes), a HP technician found radiation levels in excess of 1 rem per hour when performing a routine survey to support removal of the hot spot flush rig. The HP technician established proper controls and posting for the area and discovered that local shielding around the flush rig had been disturbed. Does this count against the technical specification high radiation area occurrence PI?

Response Yes, because the circumstances represent the creation of a technical specification high radiation area (> 1,000 mrem/hour) without the proper corrective actions (i.e., posting and controls) being taken. The dosimeter alarms that occurred represented an opportunity for timely corrective action to be taken by Health Physics, i.e., to re-evaluate the radiological conditions in the area and establish proper controls and posting. The opportunity was missed when the workers did not promptly notify Health Physics about the dosimeter alarms. If Health Physics had been promptly notified and responded properly in a timely manner, this would not count against the PI.

ID 240

Posting Date 01/10/2001

Question A Technical Specification High Radiation Area Performance Indicator occurrence is defined as a nonconformance with technical specifications and comparable requirements in 10CFR20 applicable to high radiation areas (>1 rem per hour) that results in the loss of radiological control. What are the comparable requirements in 10CFR20 applicable to these high radiation areas?

Response The comparable requirements in 10CFR20 applicable to high radiation areas (>1 rem per hour) are found in 10CFR20.1601 "Control of access to high radiation areas". Paragraphs (a), (b), (c), and (d) apply.

ID 203

Posting Date 08/30/2000

Question Because of a breakdown in communications between the rad waste and health physics groups, a post-job survey was not performed following completion of a resin sluicing evolution. Several hours later, health physics became aware of the breakdown in communication and performed a survey of the area that found dose rates greater than 1500 mrem per hour at 30 cm from the spent resin liner. The licensees Technical Specifications require areas with dose rates greater than 1000 mrem per hour to be controlled as a locked high radiation area. However, follow-up action to the survey was not properly prioritized within the health physics group and the area remained unguarded and unlocked until the next day before it was controlled in accordance with the Technical Specifications. Do these events constitute "concurrent nonconformances" as used in the Performance Indicator definition, and therefore, one PI occurrence?

Response No. The definitions for both the Technical Specification High Radiation Area Occurrence and the Very High Radiation Area Occurrence refer to A nonconformance (or concurrent nonconformances) with technical specifications and comparable requirements in 10 CFR 20 applicable to technical specification high radiation areas (>1 rem per hour) that results in the loss of radiological control over access or work activities.. As used in these definitions, concurrent means at the same time and resulting from the same cause. During the initial events in this example, the failure to perform a timely radiation survey was the cause of the failure to post the area, control access to the area and provide dosimetry as required by Technical Specifications. They are therefore concurrent nonconformances and constitute a single PI count. However, after the survey was performed, the failure to establish proper controls over access to the area in a timely manner was caused by a separate breakdown that could not be considered concurrent with the initial failure to perform the survey. This is an example of a sequential failure that warrants a second PI count.

ID 132

Posting Date 04/01/2000

Question For multiple unit sites, if a PI-reportable condition occurs on one unit, e.g., a Technical Specification high radiation area occurrence inside the Unit 1 containment building, is it necessary to report the occurrence in the indicator for all units?

Response Yes. The PI is a site-wide indicator. The current reporting mechanism requires that occupational radiation safety occurrences be input identically for each unit. However, the occurrence is only counted once toward the site-wide threshold value (i.e., it is not double or triple counted for multiple unit sites).

ID 131

Posting Date 04/01/2000

Question This question refers to radiography work performed at a plant under another licensees 10 CFR Part 34 license. If there is an occurrence associated with the radiography work involving loss of control of a high or very high radiation area or unintended dose, does this count under the occupational radiation safety PI?

Response No. Radiography work conducted at a plant under another licensees 10 CFR Part 34 license is outside the scope of the PI. Responsibility for barriers, dose control, etc., resides with the Part 34 licensee. The reactor regulatory oversight PIs apply to Part 50 licensee activities.

ID 130

Posting Date 04/01/2000

Question For high radiation areas (> 1 rem) where a flashing light is used as a TS required control, is it considered an occurrence under the Occupational Exposure high radiation area reporting element as a failure of administrative control if it is discovered that the flashing light has failed some time after the control was implemented? Failure of the light could be due to loss of its power source (dead battery or external power loss), mechanical failure (light bulb), etc.

Response No. The PI is intended to capture radiation safety program failures, not isolated equipment failures. This answer presumes that the occurrence was isolated and was corrected in a timely manner.

ID 95

Posting Date 02/15/2000

Question During a routine check, the keybox (containing high radiation area keys) in the health physics office was found unlocked, which is contrary to plant procedures. A follow-up investigation determined that all keys were accounted for and no keys had been issued or used in an unauthorized manner. Does this count against the PI.

Response No. Although this situation apparently represents a nonconformance with plant procedures, it does not appear to be a situation that would be counted against the PI. The question is whether the keys were administratively controlled per the technical specifications. From the description of the circumstances, administrative control over the keys was maintained.

ID 112

Posting Date 01/07/2000

Question Three individuals entered a radiological area to perform preventative maintenance work on a valve. Each of the workers was provided an EPD, worn on the chest, with an alarm setting of 100 mrem which also served as the administrative dose guideline for the entry. The EPD setting, and the location of the EPD on the chest, was based on a survey that indicated that the highest source of exposure was the valve itself. Upon exiting the area the individual doses, as indicated by the EPD, ranged from 75-90 mrem. However, a follow-up survey of the area revealed that a pump, located behind where the individuals were working on the valve, represented a higher source of exposure than the valve. This was apparently missed during the pre-job survey of the work area. Therefore, the EPD, located on the chest, were not properly placed to monitor dose at the point of highest exposure. An evaluation of stay-times and orientation of the individuals in the work area determined that the

actual exposures were three times what was indicated by the EPD. Does this count under the PI? If so, since three individuals were involved, would this be 1 or 3 counts under the PI?

Response Yes. This should be counted under the PI. As described, there clearly was a degradation or failure of one or more radiation safety barriers. From the example, the unintended exposure for the three individuals ranged from 125 to 170 mrem, which each exceeded the 100 mrem dose-screening criterion. Although three individuals were involved, there was only one occurrence involving degradation or failure of one or more radiation safety barriers. Therefore, this would only be counted once under the PI.

ID 111

Posting Date 01/07/2000

Question A team of workers, including a health physics technician, made a containment entry at power to investigate possible primary system leakage. Each team member was provided an EPD set to alarm at 200 mrem, which was the administrative dose guideline established for the entry. The walkdown in containment took longer than expected, and eventually several of the EPDs began to alarm, having reached the alarm setpoint of 200 mrem. After discussion with the rest of the team, the health physics technician (as permitted by plant procedures) authorized an extension of the administrative dose guideline to 300 mrem to complete the walkdown. This action was taken to minimize the overall dose that would be incurred if the team were to exit the containment, regroup, and then make a second entry to complete the walkdown. When the team completed the walkdown and exited the containment, two of the team had received a dose of 325 mrem. Does this occurrence count against the PI?

Response No. This occurrence should not be counted against the PI because the resulting dose was only 25 mrem greater than the revised guideline of 300 mrem. The use and specification of administrative dose guidelines is the responsibility of the licensee. As described in the example, the revision to the administrative dose guideline was conducted in accordance with the plant procedures or program. Therefore, the revised guideline would be applicable to the PI.

ID 110

Posting Date 01/07/2000

Question The administrative dose guideline for an individual working in a high radiation area was established via an EPD alarm setpoint at 100 mrem. When exiting the area, the individual noted that the EPD alarm was sounding and the indicated dose was 250 mrem. Due to excessive noise, the individual had not heard the alarm while in the high radiation area. Should this be counted under the PI.

Response Yes. The impact of excessive noise on the effectiveness of the EPD alarm as a dose control measure was not properly evaluated, e.g., as part of the area survey or review of the work scope. This represents a degradation or failure of a radiation safety barrier.

ID 109

Posting Date 01/07/2000

Question Upon exiting from working in the fuel transfer canal, an individual monitored himself with a frisker and detected facial contamination. Follow-up investigation determined that the individual received an intake that resulted in a committed effective dose equivalent (CEDE) of 110 mrem. The pre-job evaluation did not anticipate a potential for an intake and no administrative guideline for internal dose was specified for the work. Should this be counted under the PI for unintended exposure?

Response Yes. This should be counted against the PI. Since internal dose apparently was not anticipated as part of the job planning and controls, then the 110 mrem CEDE should be applied under the PI, which exceeds the 100 mrem TEDE criterion. For similar situations involving shallow dose equivalent, lens dose equivalent, and committed dose equivalent, where such dose has not been anticipated as part of the job planning and controls, the dose received should be applied to the respective criteria.

ID 108

Posting Date 01/07/2000

Question Is the determination of the amount of dose received as the result of an unintended exposure occurrence based solely on the dose tracking method being used (e.g., EPD or stay-time tracking), or can other data be used? For example, upon exiting a radiological area, an individuals EPD indicates that the unintended exposure is 125 mrem. A subsequent evaluation of thermo-luminescent dosimeter data indicates that the unintended exposure is 75 mrem. Which result should be used in determining if the occurrence should be counted under the PI?

Response The best-available data relevant to the PI should be used to determine whether any of the PI dose-screening criteria have been exceeded.As described in the example, the determination should include an evaluation of which data more accurately represents the dose received which is the result that should be applied to the PI dose-screening criteria. For example, if there is reason to believe that the EPD data is invalid, e.g., due to over-response to the type of radiation involved, radio-frequency interference, or equipment malfunction, then other data including the TLD results may be used.However, the evaluation should not lose sight of the intent of the PI. The PI is intended to identify occurrences of degradation or failure of one or more radiation safety barriers resulting in a readily-identifiable level of unintended exposure for the purpose of trending overall

performance in the area of occupational radiation safety. The dose-screening criteria serve as a tool for determining what level of dose is readily identifiable, based on industry experience, and do not represent levels of dose that are risk-significant. In fact the criteria are at or below levels of occupational dose that are required by regulation to be monitored or routinely reported to the NRC as occupational dose records.Therefore, the evaluation of resultant dose from an occurrence should not overshadow the objective of trending and correcting program discrepancies as intended by the use of the performance indicators.

ID 107

Posting Date 01/07/2000

Question With regard to unintended exposure from external sources, is the EPD alarm setpoint the required reference point that should be used for determining if the 100 mrem TEDE criterion has been exceeded?

Response No. The EPD alarm setpoint is not the only reference point (i.e., administrative dose guideline) that can be used for the unintended exposure PI. The PI Manual provides guidance that administrative dose guidelines may be established within radiation work permits or other documents, via the use of alarm setpoints for personnel monitoring devices, or other means, as specified by the licensee. However, it is up to the licensee to specify what method or methods are being applied with regard to the unintended exposure PI.

ID 106

Posting Date 01/07/2000

Question Does the PI for technical specification high radiation areas (>1 rem per hour) and very high radiation areas apply to spent fuel pools?

Response In general, spent fuel pools are not considered high radiation areas because of the inaccessibility of radioactive materials that are stored in the pool, provided that: 1) control measures are implemented to ensure that activated materials are not inadvertently raised above or brought near the surface of the pool water, 2) all drain line attachments, system interconnections, and valve lineups are properly reviewed to prevent accidental drainage of the water, and 3) controls for preventing accidental drops in water levels that may create high and very high radiation areas are incorporated into plant procedures ((Regulatory Guide 8.38). However, when a diver enters the pool to perform underwater activities, or upon movement of highly radioactive materials stored in the pool, proper controls must be implemented. Health Physics Position No. 016 also provides guidance on the applicability of access controls for spent fuel pools.

ID 105

Posting Date 01/07/2000

Question Plant procedures include a provision that approval of both the operations shift supervisor and the health physics supervisor is required for issuance of keys to very high radiation areas. This provision is in addition to that for issuance of high radiation area keys, which only requires the approval of the health physics supervisor. If a very high radiation area key is issued without the approval of the operations shift supervisor, i.e., contrary to the plant procedure, does this count against the PI.

Response Yes. This should be counted against the PI. The criteria for very high radiation area occurrences are based on nonconformance with 10 CFR Part 20 and licensee procedural requirements that result in the loss of radiological control over access to or work within a very high radiation area. Part 20.1602 requires that licensees shall institute additional measures to ensure that an individual is not able to gain unauthorized or inadvertent access to very high radiation areas. Such additional measures are typically implemented through plant procedures or engineered controls because there is no technical specification specifically for very high radiation areas. Therefore, occurrences that involve a failure to implement such additional measures should be counted against the PI. Regulatory Guide 8.38 describes several additional measures that are acceptable to the staff.

ID 104

Posting Date 01/07/2000

Question An individual accessed a high radiation area (>1 rem per hour) and was provided with a radiation survey instrument (i.e., a radiation monitoring device that continuously indicates the radiation dose rate in the area). Access was made under an approved radiation work permit (RWP) which specified a maximum allowable staytime that was complied with. Subsequent to the access, it was determined that the radiation survey instrument provided to the individual had not been source-checked daily or prior to use as specified in plant procedures. The radiation survey instrument was then tested and determined to be fully operable and within calibration. Should this be counted against the PI?

Response No. If the applicable provisions of technical specifications (or licensee commitments for alternate control for high radiation areas if the technical specifications do not include provisions for high radiation areas) do not explicitly require the source check, then this should not be counted against the PI. Although this situation appears to represent a nonconformance with plant procedures, the performance basis for the PI appears to have been met in that the radiation survey instrument was, in fact, operable and in calibration.

ID 103

Posting Date 01/07/2000

Question An independent verification was not made to ensure that the door of a high radiation area (>1 rem per hour) was secured after exiting the area. The independent verification is required by plant procedures as a defense-in-depth measure. It is not explicitly required by technical specifications. A follow-up investigation determined that the door was, in fact, secured. Should this be counted against the PI?

Response No. This type of occurrence should not be counted against the PI. The reference criteria for the PI for technical specification high radiation areas (>1 rem per hour) are the technical specifications (or licensee commitments for alternate controls for high radiation areas if the technical specifications do not include provisions for high radiation areas) and applicable provisions of 10 CFR Part 20. Licensees may opt to implement additional controls, i.e., beyond what is required by technical specifications and 10 CFR Part 20, but such controls are outside the scope of the PI.

ID 102

Posting Date 01/07/2000

Question A health physics technician exited a contaminated high radiation area (>1 rem per hour), secured the access door, removed his protective clothing, and left the high radiation area key at the stepoff pad. The technician went to a nearby frisker to check himself for contamination, and then returned to the stepoff pad to retrieve the key. Should this be counted against the PI with regard to administrative control of the key?

Response No. This should not be counted under the PI. It does not represent a loss of administrative control over the key.

ID 101

Posting Date 01/07/2000

Question An individual enters an area (not posted and controlled as a high radiation area) and his EPD alarms on high dose rate. The individual promptly exits the area and notifies health physics. . Follow-up surveys by the health physics staff indicated that radiation dose rates in the area were in excess of 1 rem per hour. Proper controls and posting were established for the area. Does this count against the PI?

Response Yes. As described, this occurrence should be counted against the PI. It appears that the high radiation area (>1 rem per hour) existed prior to access being made to the area, and that proper posting and controls were not in place to prevent unauthorized entry, as required by technical specifications.

ID 100

Posting Date 01/07/2000

Question During performance of routine radiation surveys a health physics technician determined that the radiation levels in an area were in excess of 1 rem per hour. Proper controls and posting were established for the area. The increase in radiation levels was due to a change in plant system configuration made earlier in the shift. Does this count against the PI?

Response The answer to this question depends upon the specific circumstances, for example, whether the survey and actions taken were timely and appropriate, whether the potential for 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. However, if surveys are not performed or controls are not established in an appropriate and timely manner, then such occurrences may be countable against the PI.It is not practical to define specific criteria for timely and appropriate for generic application. Such occurrences should be evaluated taking into account the circumstances that led to the change in radiological conditions and the scope and purpose of the survey that identified the change in conditions.

ID 99

Posting Date 01/07/2000

Question A wire cage had been constructed around an area of the plant containing a resin transfer line that, during resin transfer operations, is subject to transient radiation levels in excess of 1 rem per hour. The wire cage was constructed in a manner to preclude personnel access to areas where the dose rates exceed 1 rem per hour, sometimes referred to as a cocoon. The caged area is located within a room that is posted and controlled as a high radiation area. Does the PI for technical specification high radiation areas (>1 rem per hour) apply to this situation.

Response No. Health Physics Position No. 242 provides guidance that 10 CFR Part 20 requirements for high radiation areas do not apply to such areas that are not accessible, e.g., cocooned areas. So long as the dose rates 30 cm beyond the caged area do not exceed 1 rem per hour, the PI does not apply.

ID 98

Posting Date 01/07/2000

Question While individuals were working in an area, the local area radiation monitor alarmed. The workers promptly exited the area and notified health physics. Follow-up surveys by the health physics staff indicated that radiation dose rates in the area had increased to a level in excess of 1 rem per hour. Proper controls and posting were then established for the area. Does this count against the PI?

Response No. As described, this occurrence would not appear to be countable against the PI. The purpose of the area radiation monitors is to alert personnel to increases in radiation levels. It appears that the personnel responded appropriately to the alarm by exiting the area and notifying health physics, and that proper follow-up actions were then taken with regard to implementing controls as required by the technical specifications. However, the circumstances that led to the increase in dose rates and the resultant dose to the individuals should be evaluated per the criteria for the Unintended Dose element of the PI.

ID 97

Posting Date 01/07/2000

Question An individual entered a high radiation area (>1 rem per hour) with an electronic personnel dosimeter (EPD) that was not turned on. Does this count against the PI?

Response Yes. The technical specifications typically provide several options for monitoring of individuals accessing high radiation areas, including the option of being provided a radiation monitoring device that continuously integrates the radiation dose in the area and alarms when a preset integrated dose is received" (e.g., a functioning EPD). If that was the applicable option in this situation, and none of the other options were in effect, then the occurrence should be counted under the PI.

ID 96

Posting Date 01/07/2000

Question A door to a high radiation area (>1 rem per hour) was found unlocked and unguarded. In a similar occurrence, the gate to a high radiation area (>1 rem per hour) controlled with flashing lights was found unlatched and unguarded. A follow-up investigation in both cases indicated that no unauthorized entry had been made into the area. Do these occurrences count against the PI?

Response Yes. Such occurrences should be counted under the PI as nonconformance with technical specifications. Typical wording in technical specifications states that such areas shall be provided with locked or continuously guarded doors to prevent unauthorized entry, and that areas with flashing lights shall be barricaded. Whether anyone accessed the area is not material to meeting the technical specification requirement.

ID 94

Posting Date 01/07/2000

Question A key to the door of a high radiation area (>1 rem per hour) was issued to an individual. The individual used the key to provide access to the high radiation area by plant personnel. It was subsequently discovered that the individual was not qualified to be issued high radiation area keys. Does this count against the PI?

Response Yes. The question is whether this situation constituted a nonconformance with the technical specifications for administrative control of high radiation area keys. For example, typical wording in technical specifications is that the keys shall be maintained under the administrative control of the Shift Foreman on duty or health physics supervision.

ID 93

Posting Date 01/07/2000

Question During a routine check of high radiation area doors and gates, a door popped open when tested. Follow-up investigation determined that the latching mechanism had failed due to a mechanical defect. A similar issue regards the discovery of loose mounting bolts on a high radiation area gate. The looseness of the mounting bolts could have allowed enough movement for someone to force the gate open. No one had actually made an unauthorized entry into the high radiation area in either case. Are such situations counted against the PI?

Response No. This type of situation would not be counted against the PI if it was identified and corrected in a timely manner, appeared to be an isolated occurrence, and had not led to an unauthorized entry into a high radiation area (>1 rem per hour). In essence, these situations represent the discovery of a deficient condition and do not reflect a nonconformance with applicable technical specifications or 10 CFR Part 20 requirements.

ID 92

Posting Date 01/07/2000

Question Some radiological areas are posted or controlled as locked high radiation areas for precautionary or administrative purposes, even though the dose rates are not actually in excess of 1 rem per hour. Does the Technical Specification High Radiation Area (>1 rem) element of the Occupational Exposure Control Effectiveness PI apply to such areas?

Response No. The Technical Specification High Radiation Area (>1 rem) element of the PI applies to areas that are accessible to individuals, in which radiation levels from radiation sources external to the body are in excess of 1 rem (10 mSv) per hour at 30 centimeters from the radiation source or 30 centimeters from any surface that the radiation penetrates.

ID 91

Posting Date 01/07/2000

Question We are currently reviewing our corrective action program documents to identify radiological occurrences that should be counted under the PI for Occupational Exposure Control Effectiveness. In conducting this review, we are trying to evaluate some occurrences that were not analyzed (at the time of occurrence) using the PI criteria, i.e., we are applying the PI criteria retrospectively. What new criteria are established in the PI for Occupational Exposure Control Effectiveness? How should such criteria be applied retrospectively?

Response Response is in preparation or review.

Public Radiation Safety

PR01 RETS/ODCM Radiological Effluent

ID 90

Posting Date 01/07/2000

Question The PI for RETS/ODCM radiological effluent occurrences includes the number of occurrences each quarter involving assessed dose in excess of the indicator values. However, some data utilized in assessing dose for radiological effluents may not be available at the time of making quarterly PI reports. For example, the analytical results for composite samples are typically not finalized within the PI reporting period following the end of the quarter. How should this be handled with regard to making the quarterly PI reports?

Response It is understood that not all effluent sample results are required to be finalized at the time of submitting the quarterly PI reports. Therefore, the reports should be based upon the best-available data. If subsequently available data indicates that the number of occurrences for this PI is different that that reported, then the report should be revised, along with an explanation regarding the basis for the revision. From a practical perspective, it is very unlikely that the data that is typically not available at the time of PI reporting would have the effect of causing a change in the reported number of occurrences. The circumstances associated with an occurrence as defined in this PI would be expected to include numerous indications, not limited to composite sample analysis, that there was an occurrence, for example elevated RCS activity, transient events, and effluent radiation monitor indications.

Physical Protection

PP01 Protected Area Equipment

ID 279

Posting Date 07/12/2001

Question **Scheduled Equipment Upgrade**

During a recent NRC Security Inspection (IP 71130.03), NRC Contractors were able to defeat the Intrusion Detection System (IDS) in several areas, by using assisted jumps. An engineering evaluation was issued and formal Modification/ upgrade action was initiated that directed the installation of additional razor wire to prohibit attempts to circumvent the IDS system without being detected. Is a physical modification to a protected area boundary, that is designed to prohibit the defeat of a Intrusion Detection System (IDS) component considered to be a system/ component modification or upgrade as stated in the Clarifying Notes to NEI 99-02 under Scheduled Equipment Upgrade (and as augmented by FAQ 259)?

Response Yes. A modification such as that described above would be considered a system/component modification or upgrade because the razor wire barrier is acting as an ancillary system. The hours would stop being counted when the modification/upgrade was formally initiated as defined in the Scheduled Equipment Upgrade paragraph of NEI 99-02 Rev 1.

ID 269

Posting Date 05/31/2001

Question For sites that do not use CCTV for primary assessment of the perimeter IDS, how is the Indicator Value for the Protected Area Security Equipment Performance Index calculated?

Response Continue calculating the indicator in accordance with NEI 99-02.

ID 256

Posting Date 04/01/2001

Question For Security Intrusion Detection Systems (IDS), if the number of IDS false alarms exceeds x number per hour, the licensee considers the IDS segment failed and implements compensatory measures for the IDS segment. There are two questions:

1) If an IDS segment is declared failed (but left in service) and security personnels inspection identifies no reason to contact the maintenance organization for resolution and operability testing of the IDS segment by security personnel is successful (without performing corrective maintenance) should compensatory hours be counted for the time period that the IDS was considered as failed?

2) If an IDS segment is declared failed (but left in service) and security personnel contact the maintenance organization for resolution, the maintenance evaluation does not disclose any malfunction, and operability testing of the IDS segment by security personnel is successful, should compensatory hours be counted for the time period that the IDS was considered as failed?

Response 1) If the false alarms exceed the station security program limit, then the compensatory hours are counted regardless of which personnel evaluate the condition; provided it is in accordance with the station security program. In the absence of guidance in the security program, qualified individuals can disposition the condition.
2) Yes. See answer to 1.

ID 259

Posting Date 03/02/2001

Question **(This FAQ is a replacement for FAQ 250. FAQ 250 has been withdrawn)**

If a new Intrusion Detection System (IDS) or Closed Circuit Television (CCTV) design change package has been prepared by Engineering and funding for the new upgrade has been approved by management but the physical installation will not occur immediately, when does the NEI 99-02 "Scheduled equipment upgrade" exemption occur to stop counting the compensatory hours?

Response In the situation where system degradation results in a condition that cannot be corrected under the normal maintenance program (e.g., engineering evaluation specified the need for a system/component modification or upgrade), and the system requires compensatory posting, the compensatory hours stop being counted toward the PI for those conditions addressed within the scope of the modification after such an evaluation has been made and the station has formally initiated a commitment in writing with descriptive information about the upgrade plan including scope of the project, anticipated schedule, and expected expenditures. This formally initiated upgrade is the result of established work practices to design fund, procure, install and test the project. A note should be made in the comment section of the PI submittal that the compensatory hours are being excluded under this provision. Compensatory hour counting resumes when the upgrade is complete and operating as intended by site requirements for sign-off. Reasonableness should be applied with respect to a justifiable length of time the

compensatory hours are excluded from the PI.

ID 250

Posting Date 03/02/2001

Question FAQ 250 has been withdrawn and replaced by FAQ 259.

Response

ID 253

Posting Date 02/08/2001

Question NEI 99-02 Rev. 0, page 127, "Definition of Terms" defines "CCTV" as "The closed circuit television cameras that support the IDS." and "CCTV Normalization Factor." as "the total number of perimeter cameras divided by 30. At our plant, and possibly other larger plants, other cameras referred to as "pan-tilt-zoom" or "PTZ" cameras "support" the IDS, thus could be construed to meet the definition of "CCTV."
The PTZ cameras can be positioned to monitor most perimeter zones (e.g., when perimeter cameras are unavailable), but are not physically on the perimeter. It is unclear if the PTZ cameras meet the definition of perimeter camera for inclusion in the CCTV Normalization Factor. The stated purpose of the CCTV normalization factor to compensate for larger than nominal plant sizes. Can PTZ cameras be credited in the CCTV normalization factor?

Response If conditions cause a PTZ to be used for primary assessment, then it would count towards the calculation of the normalization factor. PTZ cameras that are used to provide additional information to the perimeter cameras used for primary assessment or as backup to perimeter cameras should they be out of service would not be counted in the calculation of the normalization factor.

ID 230

Posting Date 10/31/2000

Question If perimeter intrusion equipment, CCTV monitoring equipment or systems supporting their functionality are damaged or destroyed by environmental conditions and remains unable to perform their intended function after the condition subsides (e.g., a lightning strike, wind, ice, flood) do you need to count any hours towards the performance indicator?

Response No. If after the environmental condition clears, the zone remains unavailable, despite reasonable recovery efforts, the hours do not have to be counted.

ID 189

Posting Date 06/14/2000

Question When rounding to the nearest tenth of an hour for counted comp. hours, at what point of the data collection/computation process is the rounding applied after an incident or at the end of each month?

Response For this performance indicator, rounding may be performed as desired provided the reported hours are expressed to the nearest tenth of an hour. For all other performance indicators, rounding of collected data is not necessary. Data should be reported to the available accuracy. Appropriate rounding is performed during the computation of the performance indicator.

ID 185

Posting Date 05/24/2000

Question Appendix D: Surry Site

At Surry Power Station we have only one full time CCTV camera that is used as part of the PA perimeter threat assessment. With only one CCTV camera, that has been reliable, we have not had any compensatory hours to report for this portion of the PI. This results in what might seem to be an artificially high performance index for this PI since the CCTV camera portion of the indicator is equally weighted with the IDS portion. Is it appropriate to continue to report CCTV camera compensatory hours for a site with such a low number of CCTV cameras?

Response Continue to report in accordance with the current guidance in NEI 99-02. That is, report compensatory hours for the single CCTV camera as they occur. Put a note for this PI in the comment section submitted to the NRC similar to the following: Performance data reflects one CCTV camera.

ID 184

Posting Date 05/24/2000

Question Appendix D: North Anna Site
At North Anna Power Station we have only one part time CCTV camera that is used as part of the PA perimeter threat assessment during refueling outages. With one part time CCTV camera, that has been reliable, we have not had any compensatory hours to report for this portion of the PI. This results in what might seem to be an artificially high performance index for this PI since the CCTV camera portion of the indicator is equally weighted with the IDS portion. Is it appropriate to continue to report CCTV camera compensatory hours for a site with a low number of and infrequently used CCTV cameras?

Response Continue to report in accordance with the current guidance in NEI 99-02. That is, report compensatory hours for the part time CCTV camera as they occur. Put a note for this PI in the comments section submitted to the NRC similar to the following: Performance data reflects zero, (or X), hours of CCTV camera operation during this reporting period.

ID 163

Posting Date 05/02/2000

Question Is the tamper detection system considered part of the IDS? For example, if the tamper detection system is being monitored for compensatory measures, but the IDS is properly functioning, do licensees need to count these compensatory hours?

Response Not if IDS is functioning as intended.

ID 162

Posting Date 05/02/2000

Question NEI 99-02 under the Preventive maintenance section indicates that during preventive maintenance or testing, cameras that do not function properly and can be compensated for by means other than posting an officer, no compensatory man-hours are counted. Does this exclusion only apply to camera events discovered during the above mentioned times or can this exclusion be applied to any time a camera can be compensated for by means other than posting an officer?

Response The PI counts compensatory man-hours. Any compensatory actions other than posting a security officer (e.g., use of alternate equipment) are not counted. Note: If a security officer is normally posted for a zone (as a normal post, not compensating), and he is now told to comp a zone because cameras are not working, these hours would count.)

ID 161

Posting Date 05/02/2000

Question Variable Normalization Factor

During steady state operations our site has one access portal open for personnel to enter the protected area. During an outage we open a second access portal. The change in protected area barrier configuration affects the number of zones that are used. The result is we have a 1.9 normalization factor during steady state, and 1.95 during an outage. What value of normalization factor should we report for quarters that include an outage?

Response A prorated normalization factor that addresses periods when the second access portal is open should be reported. Add a note in the comment field describing the situation

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ID 160

Posting Date 04/01/2000

Question If a security officer is posted to comp. for two zones for 1 hour, do you count 1 or 2 compensatory hours?

Response If one security officer is posted to watch two zones for one hour, one (1) hour applies to the PI.

ID 141

Posting Date 04/01/2000

Question NEI 99-02 guidance for the Protected Area Security Equipment Performance Indicator states that when extreme environmental conditions occur that render the IDS or CCTV temporarily inoperable, the compensatory hours are not counted. In summer months, the duration of environmental conditions is typically tied to the period of time associated with storm passage. In winter months, storm passage does not as clearly represent the duration, because significant accumulations of snow and ice can remain and be an impediment to system function far beyond the passage of the storm despite removal efforts. If the IDS and CCTV are not designed to operate under such conditions, should compensatory hours count?

Response Unavailabilities due to environmental conditions beyond the design specification of the system are not counted. If after the environmental condition clears, the zone remains unavailable, despite reasonable recovery efforts, the hours do not have to be counted.

ID 140

Posting Date 04/01/2000

Question Is the performance indicator for IDS strictly looking at the protected area boundary or are vital doors included?

Response The Purpose paragraph establishes that the PI is for the plant perimeter.

ID 139

Posting Date 04/01/2000

Question For the Security Equipment indicator, there is a paragraph entitled "Scheduled equipment upgrade". This paragraph requires that if a system cannot be corrected under normal maintenance program, compensatory hours stop being counted after a modification or upgrade has been initiated. For the case where there are a few particularly troubling zones that result in formal initiation of an entire system upgrade for all zones, should we stop counting compensatory hours for all zones until the upgrade is in place?

Response No, only subsequent failures that would have been prevented by the planned upgrade are excluded from the count. This exclusion applies regardless of whether the failures are in a zone that precipitated the upgrade action or not, as long as they are in a zone that will be affected by the upgrade, and the upgrade would have prevented the failure.

ID 138

Posting Date 04/01/2000

Question Do e-fields taken out of service to support plant operations (not failures) and where guards are posted, count as Security Equipment Performance indicator compensatory hours.

Response No.

ID 137

Posting Date 04/01/2000

Question Should compensatory hours for the security computer and multiplexers be counted on the PI data being submitted.

Response Compensatory hours for this PI cover hours expended in posting a security officer as required compensation for IDS and/or CCTV unavailability because of a degradation or defect. If problems with the security computer or multiplexer result in compensatory postings because the IDS/CCTV is no longer capable of performing its intended safeguards function, the hours would count.

ID 136

Posting Date 04/01/2000

Question A CCTV camera is functioning properly, but lighting in an area is poor such that the camera cannot detect intrusion and compensatory actions are taken, do these hours count as part of the indicator?

Response The camera requires lighting to perform its function, therefore the system is not operating as intended and the compensatory hours are counted.

ID 77

Posting Date 02/15/2000

Question A previous FAQ (FAQ 60) discusses one Intrusion Detection System (IDS) segment that must be covered by two or more compensatory posts (two or more watch persons) and if you count one hour or the hours expended by the watchpersons (i.e. two or more per hour). The response states that total compensatory man-hours should be counted and that this performance indicator measures total man-hours of compensatory action vs. total hours of compensatory action.

At our Station, we have a situation where security persons are already in place at continuously manned remote location security booths around the perimeter of the site. In the event of a need to provide compensatory coverage for the loss IDS equipment, security persons already in these booths can fulfill this function. More than one person can be assigned to provide the coverage, since more than one person may be readily available. The question now becomes, do we need to count all of the persons that have been assigned to fulfill the compensatory function when some of the persons may have been assigned when it was not necessary to do so, but was done as a matter of convenience.

Response Only the required compensatory man-hours should be counted. If more than one person is required to provide coverage due to the lost equipment, then the hours of each should be counted toward this indicator.

ID 83

Posting Date 01/07/2000

Question How must we address extreme environmental conditions. A steady rain is not a "severe storm". "Sun glare" is not an extreme condition. Excessive summer heat reflecting off of a hot roof that renders the IDS inoperable for brief periods, although not an extreme environmental condition, inhibits proper operation for several consecutive days at about the same time. What if a heavy rain leaves a puddle of water that makes the IDS inoperable for several hours. Conservatively reporting environmental effects on protection equipment could cause an indicator to be unacceptable. If the clarifying note addressed "adverse environmental conditions", all weather related degradations would not be counted.

Response The clarifying note is intended to allow exemption of compensatory hours that are required due to environmental conditions that exist beyond the design specifications of the system. The question to ask is, Is the system performing in accordance with its design specifications? If the system is not designed to function during certain instances of sun glare, the hours do not have to count.

ID 82

Posting Date 01/07/2000

Question In the security equipment PI, the terms corrective maintenance and Preventive maintenance are used. However, there is another subset of maintenance - predictive maintenance - and it is not clear whether to consider it preventative (exempt) or corrective (non-exempt).

Predictive maintenance occurs on equipment that is currently performing its intended safety function satisfactorily (i.e., can pass surveillances and is OPERABLE), but has exhibited symptoms of declining performance (i.e., increased false alarms may indicate the need for insulator cleaning in advance of the routine PM cleaning or before eventual failure due to salt buildup; or a weak line signal may indicate the desirability of computer board replacement in advance of waiting for board failure).

Response Predictive maintenance is treated as preventive maintenance. Since the equipment has not failed (remains capable of performing its intended detection (safety) function), any maintenance performed in advance of its actual failure is preventive. It is not the NRC's intent to create a disincentive to performing maintenance to ensure the security systems perform at their peak reliability and capability

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ID 81

Posting Date 01/07/2000

Question When determining the need to compensatory post an Intrusion Detection System when it can not perform its intended safety function, there are three types of failures: (1) inability to detect intrusion; (2) inability to detect IDS sabotage (i.e., tamper alarms); and (3) inability to note equipment problems (i.e., supervisory alarm). Clearly, items 1 and 2 are failures and compensatory hours should be counted; however, what about failures of the supervisory sub-system?

Response IDS equipment issues that do not require compensatory hours would not be counted.

ID 80

Posting Date 01/07/2000

Question A licensee performs a routine surveillance on a security Intrusion Detection System (IDS) or Closed Circuit TV (CCTV). During the surveillance, the equipment is determined to be inoperable (not capable of performing its intended safety function). When does the inoperability start.

Response The metric is based on the comp hours and starts when the IDS or CCTV is actually posted. There is no "fault exposure hours" or other consideration beyond the actual physical compensatory posting.

ID 68

Posting Date 01/07/2000

Question If a compensatory measure such as positioning a Pan-Tilt-Zoom camera in an area that compensates for a out of service fixed zone camera, does that count against the Protected Area Security Equipment PI even though no additional man-hours are required for the compensatory measure.

Response This indicator utilizes compensatory man-hours to provide an indication of CCTV and IDS unavailability. Other compensatory measures would not be counted as part of this indicator.

ID 61

Posting Date 11/11/1999

Question Compensatory hours are not double counted when compensatory measures are assigned to multiple points (i.e. a single officer spending 4 hours watching both a camera and a zone). However, where are the comp hours assigned, to the camera or the zone.

What If 1 MSF (Member of the Security Force) spent a total of 12.5 hours (one standard shift) on compensatory measures for malfunctioning equipment (0530 - 1800). Of the 12.5 hours =

0530 - 1400 MSF compensated for zone 4 (IDS) totaling 8.5 hrs

0700 - 1200 MSF compensated for camera 4 (CCTV) totaling 5 hrs

0900 - 1800 MSF compensated for camera 5 (CCTV) totaling 9 hrs

How should we divide the hours up?

Response Compensatory hours expended to address multiple equipment problems are assigned based upon the piece of equipment that first required compensatory hours. When this first piece of equipment is returned to service and no longer requires compensatory measures, the second piece of equipment carries the hours, etc. In the offered example, IDS-Zone 4 would be assigned 8.5 hours and CCTV-camera 5 would be assigned 4 hours.

ID 60

Posting Date 11/11/1999

Question If two IDS segments can be covered by a single comp post (one watchperson) then the guidance says to only count one hour (don't double count the single post). What if one IDS segment must be covered by 2 or more comp posts (two or more watchpersons), do you count one hour or the hours expended by the watchpersons (i.e., 2 or more per hour).

Response Total compensatory man-hours should be counted. This performance indicator measures total man-hours of compensatory action vs. total hours of compensatory action.

ID 59

Posting Date 11/11/1999

Question For Security Intrusion Detection Systems (IDS), if the number of IDS segment false alarms exceeds 5 per hour, licensees declare the IDS segment inoperable (due to excessive false alarms. Note, these are not nuisance nor environmental alarms.), comp post the segment, repair/test the segment, return the segment to operable and remove the comp post. The question is, if an IDS segment is removed from service and comp posted, but the resultant maintenance does NOT disclose any malfunction and the system is returned to service with essentially no corrective maintenance (some minor tweaking of system sensitivity might be done since it is out of service, but for this discussion the sensitivity was not initially mis-set), do you count the comp posting hours against the metric.

Response If there is no equipment malfunction and the system would still have alarmed during intrusion (still capable of performing its intended function), then the compensatory man hours that were established as part of a precautionary maintenance activity would not be counted.

ID 57

Posting Date 11/11/1999

Question For a multi unit site how are the CCTV and IDS Compensatory Hours to be reported? Are they reported under only 1 unit, all units, divided between the units, or separately as a site-wide program?

Response Information supporting performance indicators is reported on a per unit basis. For performance indicators that reflect site conditions, this requires that the information be repeated for each unit on the site.

Physical Protection

PP02 Personnel Screening Program

ID 134

Posting Date 04/01/2000

Question Should we include such things as "entry into a vital Area without proper authorization, or just the reporting requirements that would be reported if 10 CFR 73.56 or 10 CFR 73.57 were not met as outlined in Generic Letter 91-003 and NUREG 1304?"

Response GL 91-03 and NUREG 1304 are not germane. The only Reportable event is that defined in the PI - "a failure in the licensee's program that requires prompt regulatory notification." If you did not make a one-hour report concerning a significant failure to meet regulation it is not included for PI purposes.

ID 133

Posting Date 04/01/2000

Question Personnel Screening Program Performance indicator: As written in NEI 99-002 it appears that this indicator only applies to reportable conditions in 10 CFR 73.56 & 57, but it needs to be absolutely clear.

Response The PI applies to § 73.56 and 73.57 and not to all of Part 73.

Physical Protection

PP02-PP03 Physical Protection

ID 128

Posting Date 04/01/2000

Question For the Personnel Screening and Fitness for Duty indicator - it is not stated that the date to be used for reporting or what quarter to report an event in is the LER date. Is this an accurate assumption? This would be the same as the SSFF date requirement.

Response The criterion for reporting of performance indicators is based on the time the failure or deficiency is identified, with the exception of the Safety System Functional Failure indicator, which is based on the Report Date of the LER.

ID 127

Posting Date 04/01/2000

Question Clarifying Notes for both the Unescorted Access Authorization Program and FFD performance indicators imply that if an event is reported appropriately in accordance with either the reporting criteria of Part 26 or Part 73.55 then the program is working as designed and there is no event counted in the PI data. What then is the meaning/purpose of the sentence on page C-6 of the guidance document of the cornerstone document: "...data is currently available and there are regulatory requirements to report significant events"...?

Response The sentence before the quoted piece used the term "program degradations." The intention is to keep the reported information in two groups:· Specific reports required by regulation (e.g., operator tested positive for drugs) which means the program is working as intended and not to be included in the PI, and· Significant programmatic failures of the implemented regulatory requirements that would amount to one-hour type reports - these are the only reports included in the PIs for access authorization or fitness-for-duty.

Physical Protection
PP03 FFD/Personnel Reliability Program

ID 336

Posting Date 03/20/2003

Question The clarifying note for the Fitness-For-Duty / Personnel Reliability Program PI states that the indicator does not include any reportable events that result from the program operating as intended. There is also an example provided that indicates that a random test drug failure would not count since the program itself was successful.

The following example is somewhat more complex and would help to further clarify treatment of situations associated with random testing:

Example - A licensee supervisor is selected for a random drug test but refuses and resigns prior to providing a specimen. All actions taken upon discovery are in accordance with Part 26 and the program functions as intended. (The subject event had been reported to the NRC Operations Center within 24-hours of occurrence in accordance with 10 CFR 26.73. The subject event was included in the 6-month report of performance data required by 10 CFR 26.71. NEI's Personnel Access Data System (PADS) had been immediately updated such that the subject individuals record adequately reflects this event.) The subject supervisor, prior to the event, was expected to be effectively practicing the behavioral observation techniques (for which supervisors are required to be trained per 10 CFR 26.22) in his role as a supervisor. Would this example count as a PI data element?

Response No. The program functioned as intended and the requirements of Part 26 were met

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ID 129

Posting Date 04/01/2000

Question The clarifying note for the Fitness-For-Duty / Personnel Reliability Program Performance Indicator states that the indicator does not include any reportable events that result from the program operating as intended. What is not clear is whether all 10 CFR Part 26 reportable events count as data reporting elements or not. For example, if a contract supervisor is selected for a random drug test, tests positive, and we take the proper action, does this count as a data reporting element or not? One could say that the random drug test failure is a failure to implement the requirements of 10 CFR Part 26. Alternatively, one could say that the program functioned as intended and we complied with the requirements of 10 CFR Part 26.

Response No. The example would not count since the program was successful. Only count program failures.

ID 58

Posting Date 11/11/1999

Question When reporting data for FFD/personnel screening for a multi-site company for which personnel are tested for both sites, how is the data reported?

Response The Personnel Screening Program Performance Indicator provides a measure of the effectiveness of programmatic efforts to implement regulatory requirements outlined in 10 CFR Part 73. Where a programmatic failure affected (or had the potential to affect) multiple sites, the instance is reported for each affected unit.

General

All All

ID 120

Posting Date 06/14/2000

Question FAQ 120 Withdrawn

Response

ID 119

Posting Date 06/14/2000

Question FAQ 119 Withdrawn

Response

ID 118

Posting Date 06/14/2000

Question FAQ 118 Withdrawn

Response

ID 117

Posting Date 06/14/2000

Question FAQ 117 Withdrawn

Response

ID 116

Posting Date 06/14/2000

Question FAQ 116 Withdrawn

Response

ID 115

Posting Date 06/14/2000

Question FAQ 115 Withdrawn

Response

ID 114

Posting Date 06/14/2000

Question FAQ 114 Withdrawn

Response

ID 113

Posting Date 06/14/2000

Question FAQ 113 Withdrawn

Response

ID 121

Posting Date 04/01/2000

Question When should quarterly performance indicator reports be submitted when the normal submittal date falls on a Saturday, Sunday, or Holiday?

Response The performance indicator data reports are submitted to the NRC under 10 CFR 50.4 requirements. Per 10 CFR 50.4, if a submittal due date falls on Saturday, Sunday, or Federal holiday, the next Federal working day becomes the official due date.

ID 67

Posting Date 01/07/2000

Question Individual Plant Examinations (IPEs) were established using a certain set of PRA assumptions. These included assumptions regarding the availability of equipment that perform Safety functions. The criteria used for availability decisions have varying degrees of conservatism from plant-to-plant. In some cases, these criteria may be less stringent than criteria currently used in NEI 99-02 Rev D for determining the availability of equipment within the scope of Mitigating Systems. However, these less stringent criteria give a more accurate representation of risk if they accurately determine the actual status of equipment availability to perform its function.It's possible that these less stringent criteria are still being used on a day-to-day basis (e.g., to establish risk profiles for on-line maintenance). Has this potential conflict been recognized (using different decision criteria for availability of the same equipment, depending upon what process is making the decision)? Is there an expectation to reconcile this? What effect does this have upon a plant's PRA if risk assumptions are no longer valid using 99-02 criteria? Is there an expectation that availability decisions for equipment outside the scope of the performance indicators be consistent with 99-02 criteria?

Response It is recognized that there are differences in definitions between the NRC PIs, WANO indicators, maintenance rule, and IPEs. Industry and NRC will be working in year 2000 to try to reconcile indicator definitions. NEI 99-02 applies to NRC PIs and not to operability decisions or your PRA.