TempNo.	PI	Topic	Status	Plant/ Co.
80.1	IE01	Reactor Power Indication	4/16 Introduced and Discussed 5/15 Discussed 6/18 Tentative approval	Columbia
81.3	IE03	Raccoon Intrusion	5/15 Introduced and Discussed 6/18 Tentative approval	Grand Gulf
81.4	IE03	Environmental FAQ	5/15 Introduced and Discussed 6/18 Tentative approval	Generic
82.0	MS06	PMT Issues	7/16 Introduced and Discussed	Generic
82.1	IE04	Time of Discovery	7/16 Introduced and Discussed	Generic

Plant: __Columbia Generating Station______
Date of Event: __March 22, 2008__________
Submittal Date: __April 10, 2008__________
Licensee Contact: _Greg Cullen_
Tel/email: _(509)377-6105 / gvcullen@energy-northwest.com
NRC Contact: __Zach Dunham, SRI___
Tel/email: _(509)377-2627

Performance Indicator: Unplanned Power Changes per 7,000 Critical Hours

Site-Specific FAQ (Appendix D)? No

FAQ requested to become effective when approved.

Question Section

NEI 99-02 Guidance needing interpretation (include page and line citation):
Revision 5, Page 15, Lines 14 and 15: "Licensees should use the power indication that is used to control the plant to determine if a change of greater than 20% of full power has occurred."

Event or circumstances requiring guidance interpretation:
On March 22, 2008 Reactor Feedwater (RFW) pump 1B (RFW-P-1B) experienced a speed transient which caused both RFW pump low suction pressure alarms to actuate. In response, control room staff initiated a reduction in reactor recirculation pump speed (both pumps) to reduce core flow (which reduces power) as directed by procedure. The core flow reduction was terminated after both RFW pump low suction pressure alarms cleared, as allowed by procedure. Upon termination of the flow reduction the operators assessed key plant parameters, including reactor power using the 1-minute average core thermal power (CTP) signal, and, after about 15 minutes, the 15-minute average CTP signal, and concluded that plant power was at 81% (as documented in the Condition Report and operating logs). The 1-minute and 15-minute average CTP signals are calculated using the reactor heat balance and are the normal signals used by operators to monitor and control plant power level. The 1-minute average CTP signal is driven by RFW flow and does not provide an accurate power calculation during RFW flow transients. It was not used by operators to assess power conditions during the initial RFW flow transient.

Subsequently, the control room staff requested that the Station Nuclear Engineer (SNE) provide an evaluation of peak power achieved during the transient to determine if reactor power exceeded 102% of the operating license limit. The SNE ultimately provided a plot of reactor power using an APRM simulated heat flux signal, which is not a signal used to control reactor power, nor is it a signal that is normally monitored by Operations personnel. The APRM simulated heat flux signal (a six second average of a single APRM signal, available for two of the APRMs) indicated that power had initially increased before the RFW control system recovered and brought speed (and power) back down. Since the RFW pump low suction pressure alarms did not clear at that point, operators reduced core flow. The APRM simulated heat flux signal indicates that power then went 1-3% below 80% RTP before settling out at approximately 81% RTP as conditions stabilized. Immediately following the transient the APRMs and APRM recorders were consulted for the purpose of assessing the condition of the core, but not for the purpose of assessing plant power level.

As cited above, guidance on what indications to use to determine if a change of greater than 20% of full power has occurred is “Licensees should use the power indication that is used to control the plant….” In this event the operators documented a reduction in power to approximately 81% RTP using indications available to them immediately following the transient (i.e., the 1-minute average). In addition, per Columbia operating procedures the primary power indication used to control and monitor the plant reactor power, including monitoring compliance with our license condition for reactor power, is the 15-minute average CTP signal, which is calculated using the reactor heat balance. This signal also indicated a reduction in power to approximately 81% RTP.

FAQ 227 (dated 10/31/2000) appears to be the question that led to the guidance quoted above. This FAQ asked, “For calculating the change in power, should secondary power data be used, nuclear instruments or which ever is more accurate?” The response was, “Licensees should use the power indication that is used to control the plant at the time of the transient.” In this case the operators were not controlling the plant in response to indicated power but were reducing core flow in response to the alarms. Cessation of the flow (and power) reduction was dictated by the clearing of the RFW pump low suction pressure alarms. Upon checking power level following the transient, using the 1-minute average CTP signal, it was determined that power was reduced to 81% CTP (as documented in the CR and the operating logs). The APRM simulated heat flux signal was clearly not used to control the plant, nor was it initially consulted to determine final power level or the extent of the transient. The wording of the guidance and the FAQ 227 question and response would indicate that the licensee is not required to find or use the “more accurate” indications when assessing the power change, but should use initial indications of the power level. In this case the CR, operating logs, 1-minute average CTP signal, and 15-minute average CTP signal all indicate a reduction to 81% RTP.

RIS 2007-21 generated a significant amount of discussion about monitoring of instantaneous power in Boiling Water Reactors (BWRs) and resulted in some agreement that an average CTP calculation is the best way of monitoring power. However, these calculations have inherent inaccuracies during transient conditions, particularly RFW flow transients. APRMs serve a primary purpose of performing a reactor protective trip function and also have accuracy issues as far as indication of instantaneous core thermal power. As such, they provide more insights to transient conditions, but are not as accurate for absolute power indication, and, in fact, the APRMs are calibrated against the average CTP signal.

If licensee and NRC resident/region do not agree on the facts and circumstances explain

NRC Region IV has indicated that they do not agree with use of the 15-minute average CTP signal for assessing the event because events of a different type (multiple transients or power oscillations) would be invisible or inaccurately assessed. They cite the example discussion on page 14, lines 23-30 of NEI 99-02, Revision 5, as a case where a 15-minute average would not lead to assessment of two separate unplanned power changes of greater than 20% due to the signal averaging over a relatively long period of time.

In addition, NRC Region IV considers that the reference in NEI 99-02, page 15, lines 14-15, to "use the power indication that is used to control the plant" should include all indications that are normally available to the operators for controlling plant power. For example, in response to a quickly developing transient, such as during plant response to a component failure, power indication averaged over 15 minutes may not be appropriate for controlling power whereas APRM's may be a better indicator for the operators to use during the transient response. In contrast, during a slowly developing transient, such as a controlled reduction in power, a power average may be appropriate.

Potentially relevant existing FAQ numbers

227

Response Section

Proposed Resolution of FAQ

The purpose of the indicator is to monitor the number of unplanned power changes (excluding scrams) that could have, under certain plant conditions, challenged safety functions with the intent of providing leading indication of risk-significant events (per NEI 99-02). FAQ 227 provided clarification that detailed analysis of exact core conditions is not required to meet the intent of the indicator. This PI does not specify the use of secondary calorimetric averaging (i.e., heat balance equation) to compute changes in reactor power, only that licensees are required to use the method of power determination that is used to control the plant. However, it is recognized that some power indications that are used to control the plant are not appropriate during a transient, (i.e. 15 minute calorimetric power averaging). In these situations, other indications and/or procedural guidance need to be consulted that could provide a reasonable assurance that a power change of greater than 20% did or did not occur.

In the event described above, the transient involved a brief increase in feedwater flow, which caused the RFW pump low suction alarm to activate. The operators reduced pump speed to reduce flow as directed by procedure. Initial indications following completion of the transient indicated that power stabilized at 81% power using a 1 minute power average. Since the event started at 100% power and power initially stabilized at 81% power at the end of the event the gross power change was approximately 19%; therefore, this value does not meet the reporting criteria for the PI.

If appropriate, provide proposed rewording of guidance for inclusion in next revision.

Guidance revision does not appear to be necessary at this point.

Plant: Grand Gulf Nuclear Station
Date of Event: April 29, 2008
Submittal Date: May 14, 2008
Licensee Contact: Mike Larson **Tel/email:** 601-437-6685 / mlarson@entergy.com
Licensee Contact: Steve Osborn **Tel/email:** 601-437-2344 / sosborn@entergy.com
NRC Contact: Richard Smith **Tel/email:** 601-437-4620 / rich.smith@nrc.gov

Performance Indicator: Unplanned Power Changes per 7,000 Critical Hours

Site Specific FAQ (Appendix D)? Yes or No: No

FAQ requested to become effective when approved.

<u>Question Section:</u>

NEI 99-02 Rev 5 Guidance needing interpretation (include page and line citation):
Page(s) 14 & 15.
42 Anticipated power changes greater than 20% in response to expected environmental problems
43 (such as accumulation of marine debris, biological contaminants, or frazil icing) which are
44 proceduralized but cannot be predicted greater than 72 hours in advance may not need to be
45 counted unless they are reactive to the sudden discovery of off-normal conditions. However,
46 unique environmental conditions which have not been previously experienced and could not
47 have been anticipated and mitigated by procedure or plant modification, may not count, even if
48 they are reactive. The licensee is expected to take reasonable steps to prevent intrusion of marine
49 or other biological growth from causing power reductions. Intrusion events that can be
1 anticipated as a part of a maintenance activity or as part of a predictable cyclic behavior would
2 normally be counted unless the down power was planned 72 hours in advance. The
3 circumstances of each situation are different and should be identified to the NRC in a FAQ so
4 that a determination can be made concerning whether the power change should be counted.

Event or circumstances requiring guidance interpretation:

<u>Event</u>

During the spring, the Mississippi River floods as ice melts in the north and spring rains greatly increase the river flow volume. The spring 2008 Mississippi River flooding has been more extensive than flooding seen since Grand Gulf Nuclear Station (GGNS) entered construction and operation. In fact, the Mississippi River levels were higher than any seen since 1973, when the river crested at 51.2 feet, well in excess of installed animal deterrence devices.

GGNS has a service water system that employs a radial well system for its cooling water during normal operation. These radial wells are located closer to the Mississippi River than the plant and are designed to remain functional during flooding in excess of that experienced in the spring of 2008. Although situated over dry land during most of the year, equipment to support the radial wells' operation is located on a platform approximately 26 feet above ground level sitting on pilings. The structure is protected from impact by barges or large debris being swept uncontrolled down the river by additional large pilings. A boat is required for station personnel to access the Radial Well Switchgear during times of river flooding.

At 2112 on April 29, 2008, GGNS experienced a loss of Balance of Plant (BOP) Transformer 23 resulting in a loss of the 28AG Bus and Radial Well Pumps E, F, and J. The Loss of Plant Service Water (PSW) Off-Normal Event Procedure (ONEP) was entered as well as the Reduction in Recirculation Flow ONEP. Reactor power was reduced to approximately 47% using Reactor Recirculation flow and control rod insertion. The plant responded as expected. Upon investigation into the loss of BOP Transformer 23, a dead raccoon was found in the vicinity of the transformer which clearly appeared to have come in contact with energized equipment.

The cause of the loss of BOP Transformer 23 is believed to be a short inducted by the raccoon. The flooding of the Mississippi River is believed to have allowed the raccoon to climb into the transformer area bypassing the installed prevention measures. Animal intrusion is normally prevented from the area by removal of ladder access and installed animal deterrence (approximately 8 to 10 feet high above ground) on the power poles adjacent to the transformer structure. These measures prohibit animal intrusion under normally anticipated and expected environmental conditions when animals would be present (.i.e., dry, non-flooded conditions). It was not anticipated or expected that an animal would gain access by swimming in the flooded conditions of the Mississippi River. In order to reach the Radial Well Switchgear, the raccoon either was caught-up in the river or swam a significant distance from the flooded wood line to reach the platform.

The design features were modified following the event to prevent reoccurrence.

<u>Industry Design Standards</u>

IEEE Standard 1264-1993 (R2004), “IEEE Guide for Animal Deterrents for Electric Power Supply Substations,” documents methods and designs to mitigate interruptions and equipment damage resulting from animal intrusions into electric power supply substations. The standard identifies that there are many animals including birds, mammals, reptiles, and insects that are known or potential sources of animal related outages. The standard states that a mitigation program should be put in place after experiencing an unacceptable level of animal related problems and that survey results indicate that deterrence methods are typically implemented after a substation begins to experience the animal intrusions of concern.

The standard goes on to provide examples of mitigation methods and their reported effectiveness. The standard discusses that a necessary part of the mitigation of animal intrusions is monitoring the effectiveness of installed deterrents for the type of animal and problem the deterrent is intended to mitigate. The standard identifies that often a trail and error approach is necessary to find an effective solution for each problem.

<u>Operating Experience</u>

Based upon previous operating experience, GGNS has implemented measures to mitigate the potential for animal intrusion into critical outdoor equipment. Previous land animal intrusions at GGNS and identified industry events have occurred when the animal approached the area of concern via a land route. This is the first identified event where the animal swam into the area of concern. There has been no occurrence of Radial Well Switchgear water borne animal intrusions in the history of GGNS.

The Mississippi Department of Wildlife, Fisheries and Parks (MDWFP) was contacted to obtain relevant information concerning raccoons. The following information was obtained from a Small Game Biologist for the department.

Under normal river conditions, a raccoon might swim to a know location or island. He would not expect one to swim on purpose in the flood conditions experienced in 2008. MDWFP observed greatly increased numbers of wildlife in areas not normally frequented due to the higher than normal flood conditions.

Raccoons’ do climb trees and can travel tree to tree. He would not expect a raccoon to travel tree to tree for approximately half a mile over water, swim an extended distance, and then climb a power pole to access a structure (switchgear house). His opinion was it’s more probable that the raccoon was caught-up in the river and climbed the pole seeking refuge.

Conclusion

The Mississippi River flooding level with an animal intrusion is a unique environmental condition that has not been previously experienced and therefore, could not have been anticipated and mitigated by procedure or plant modification.

Requested Interpretation

Does the GGNS down power of April 29^{th} 2008 count as an Unplanned Power Change per 7,000 Critical Hours?

If licensee and NRC resident/region do not agree on the facts and circumstances explain:

NRC Statement to be include in the Licensee's FAQ for the greater than 20% power decrease on April 29, 2008.

Facts:

- In 2002 and 2005, Grand Gulf Nuclear Station had reactor scrams due to raccoons causing ground faults to station transformers in the main station switch yard.
- The corrective actions for the first scram in 2002 did not prevent the scram that occurred in 2005.
- The licensee identified the BOP 23 transformer as vulnerable to animal intrusion following the 2002 reactor scram.
- The Mississippi river level routinely rises in the spring, requiring Grand Gulf employees to use a power boat to perform operator rounds and maintenance checks on equipment at the river.
- In June of 2006, the licensee found an injured raccoon at the base of the BOP 23 transformer. The raccoon had burn marks on its nose and hind legs. The raccoon had come into contact with live current from either the primary or secondary side of one of the platform transformers but did not cause a trip of equipment.
- In response to this event in June of 2006, the licensee placed animal guards on the wooden electrical poles by the transformer platform believed to be approximately 8-10 feet from the ground. They also removed a section of ladder going to the platform approximately 4 feet 7 inch from the ground.

The region and the resident staff have concluded that the environmental conditions which have been previously experienced at the site could have been anticipated by the licensee to mitigate the unintended down power. The staff disagrees with the licensee's assertion that the combination of a routine flooding event and repetitive animal intrusion equates to a unique environmental condition. The staff has concluded that, based on the above listed facts, the licensee should have developed corrective actions to mitigate the loss of the BOP transformer by adding animal deterrents that would be effective during flooding events. This would have prevented the occurrence of the April 29, 2008 down power event.

Potentially relevant existing FAQ numbers:

Multiple FAQs have been approved associated with a downpower which was the result of a known potential environmental hazard that manifested itself in a manner previously not experienced at the station (e.g., fish/debris/algae in amounts not previously experienced). Reference FAQs 306, 451, 448, 452, 437, 444, and 445.

Response Section:

Proposed Resolution of FAQ: This downpower counts toward the indicator. In 2002 and 2005, Grand Gulf experienced reactor scrams due to raccoons causing ground faults to station transformers. The licensee had identified that that the BOP 23 transformer is vulnerable to animal intrusion following the 2002 scram. In June 2006, the licensee discovered an injured raccoon near the base of the BOP 23 transformer and then took corrective actions to attempt to prevent future animal intrusion by installing animal guards and removing portions of a ladder. In addition, the Mississippi River routinely floods the area around the BOP 23 transformer. Although the licensee stated that the combination of the animal intrusion and flooding was the first time this was experienced at Grand Gulf, it was reasonable that the two environmental conditions could be present concurrently and that this should have been taken into consideration when choosing to provide an animal deterrent through a design change (animal guards on the poles). During the event discussions with the licensee, the licensee stated that flooding was not considered when placing the animal guards on the poles. NEI 99-02 states, “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.” Regardless of whether this event was unique, it was within the licensee’s ability to predict and be prevented; therefore, it counts towards the indicator.

If appropriate proposed rewording of guidance for inclusion in next revision.

None.

FAQ 81.4

Plant: Generic
Date of Event: NA
Submittal Date: May 6, 2008
Licensee Contact: Julie Keys
NRC Contact: Nathan Sanfilippo

Performance Indicator:IE02

Site-Specific FAQ (Appendix D)? No

FAQ requested to become effective when approved.

Question Section

NEI 99-02 page 14, lines 42 through 49 and page 15, lines 1 through 4 state: *"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."*

The NEI ROP Task Force and the NRC staff have in the past reviewed many repeat FAQs from various plants related to the exception in IE02, Power Changes Greater than 20%, from counting events caused by expected environmental problems. Typically FAQs are generated not because the site's resident inspector feels the plant's response was inadequate but because NEI 99-02 dictates it. The generation of such FAQs is an inefficient use of the industry's and NRC's time. Once the original FAQ (and implicitly the plant's plans and procedures for dealing with future similar events) has been approved, the site resident inspector should be allowed to make the determination whether the plant's response was timely and adequate. An FAQ should only be required if the resident inspector and plant do not agree the guidance has been met as is the case with the other indicators.

Response Section

The subject text should be replaced with the following :

Anticipated power changes greater than 20% in response to expected environmental problems (such as accumulation of marine debris, biological contaminants, animal intrusion, environmental regulations, or frazil icing) may qualify for an exclusion from the indicator. The licensee is expected to take reasonable steps to prevent intrusion of animals, marine debris, 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 or the event meets the guidance below.

In order for an environmental event to be excluded, any of the following may be applied:

- If the conditions have been experienced before and they exhibit a pattern of predictability or periodicity (e.g., seasons, temperatures, weather events, animals, etc.), the station must have a monitoring procedure in place or make a permanent modification to prevent reoccurrence for the event to be considered for exclusion from the indicator. If monitoring identifies the condition, the licensee must have implemented a proactive procedure (or procedures) to specifically address mitigation of the condition before it results in impact to operation. This procedure cannot be a general Abnormal Operating Procedure (AOP) or Emergency Operating Procedure (EOP) addressing the symptoms or consequences of the condition (e.g., low condenser vacuum); rather, it must be a condition-specific procedure that directs actions to be taken to address the specific environmental conditions (e.g., jellyfish, gracilaria, frazil ice, etc.)
- If the event is predictable, but the magnitude of the event becomes unique, the licensee must take appropriate actions and equipment designed to mitigate the event must be fully functional at the time of the event to receive an exclusion.
- Environmental conditions that are unpredictable (i.e., lightning strikes) may not need to count if equipment designed to mitigate the event was fully functional at the time of the event.
- Downpowers caused by adherence to environmental regulations, NPDES permits, or ultimate heat sink temperature limits may be excluded from the indicator.

The circumstances of each situation are different. In all cases, the NRC Region and Resident Inspectors should evaluate the circumstances of the power change, and if in disagreement with the licensee’s position, the event should be identified in an FAQ so that a decision can be made concerning whether the power change should be counted. If the event is truly unique, an FAQ should be submitted unless the NRC Region and Resident Inspectors agree with the licensee’s position.

FAQ 82.0

Plant: Generic
Date of Event: NA
Submittal Date: July X, 2008
Licensee Contact: Julie Keys
NRC Contact: Nathan Sanfilippo

Performance Indicator: MSPI

Site-Specific FAQ (Appendix D)? No

FAQ requested to become effective when approved.

Question Section

NEI 99-02, Appendix F, page F-25, lines 21 through 23 and page F-26, lines 1 through 9 states:

"*EDG failure to start*: A failure to start includes those failures up to the point the EDG has achieved required speed and voltage. (Exclude post maintenance tests, unless the cause of the failure was independent of the maintenance performed.)"

"*EDG failure to load/run*: Given that is has successfully started, a failure of the EDG output breaker to close, to successfully load sequence and to run/operate for one hour to perform its monitored functions. This failure mode is treated as a demand failure for calculation purposes. (Exclude post maintenance tests, unless the cause of the failure was independent of the maintenance performed.)"

"EDG failure to run: Given that it has successfully started and loaded and run for an hour, a failure of an EDG to run/operate. (Exclude post maintenance tests, unless the cause of the failure was independent of the maintenance performed.)"

The NEI ROP Task Force and the NRC staff have, in the past, spent significant time reviewing FAQs and dealing with the term "independent of the maintenance performed." The conduct of maintenance activities involves numerous support activities. It is recognized that during the conduct of a specified maintenance activity the potential exists to inadvertently induce equipment failures that would not be immediately identified or recognized. Such failures would be dependent on the maintenance activity, that is the failure would not have occurred if the maintenance had not been performed, and most likely would be identified during PMT performed prior to restoring the component to operable status. Failures that are caused by the maintenance activity should not be counted as they are **not** indicative of the reliability of the equipment that was undergoing maintenance. Licensee utilize PMT to verify that a monitored component is operable prior to returning it to service after the completion of a maintenance activity. The following guidance was developed by the NEI ROP and the NRC staff to make it easier to determine what failures, identified during PMT, are dependent on the maintenance performed and which are independent of the maintenance performed.

Response Section

Page F-26, line 34 - The following test should be inserted in NEI 99-02, Rev. 5 at line 34 on page F-26.

Treatment of failures discovered during post maintenance tests:
Failures identified during post-maintenance tests (PMT) are not counted unless the cause of the failure was independent of the maintenance performed. The maintenance scope of work includes the activities required to be performed to conduct the maintenance, including support activities, the actual maintenance activities, and the activities required for restoration of the monitored component(s) to their available and operable conditions. This includes, but is not limited to, typical tasks such as scaffolding erection and removal, coatings applications, insulation removal and installation, rigging activities, health physics activities, interference removal and restoration, as required to support and perform the required maintenance activity. Support activities may be planned, scheduled and implemented on separate work orders from the work order for the monitored component(s). System or component failures introduced during the scope of work are not indicative of the reliability of the equipment, since they would not have occurred had the maintenance activity not been performed. In addition, the potential exists that components or devices not included in the direct scope of work may be affected by the ongoing activities. Such failures are not counted providing:

- They are identified during or prior to the post-maintenance testing and are corrected prior to the component(s) being returned to operable status,
- The repair is documented in a work package, and
- The critical components not directly in the scope of work, but that have the potential to be affected by the maintenance activity, are noted by means such as cautions in the procedures, inclusion in the pre-job briefings, protection by signs, placards or padding.
- The licensee uses the corrective action program to document the basis for the determination that the cause of the failure was dependent on the maintenance performed. This determination must establish a clear relationship between the maintenance performed and the failure.

FAQ 82.1

Plant: Generic
Date of Event: NA
Submittal Date: July 8, 2008
Licensee Contact: Julie Keys
NRC Contact: Nathan Sanfilippo

Performance Indicator: IE04

Site-Specific FAQ (Appendix D)? No

FAQ requested to become effective when approved.

Question Section

"Time of discovery" should be more clearly defined in the following sections of NEI 99-02, revision 5:

- Page 29, lines 18-20, end of second paragraph in section Indicator Definition.
- Page F-5, lines 34-42, fifth paragraph in section F.1.2.1. "Actual Train Unavailability"

Background. "Time of discovery" is used in the Mitigating Systems Performance Index (MSPI) for the assignment of train unavailable hours when the train cannot perform one or more of its MSPI monitored functions. The "time of discovery" is the start time for the train unavailable hours and the end time is when the train's capability to perform its monitored function(s) is restored. Typically, "time of discovery" occurs when a component failure happens causing the train to become unavailable. At other times, a component degraded condition may occur that prevents a train from performing its monitored function(s). In some of these cases it may take an evaluation to determine the impact of the degraded condition on the train's monitored function(s).

An assumption of MSPI is that monitored function(s) are promptly restored after a component failure. ("Promptly" is not defined.) Therefore, degraded conditions are expected to be evaluated promptly so that if a degraded condition prevents the performance of a monitored function, the monitored function can be restored quickly.

For MSPI purposes, the "time of discovery" is when a component failure occurs that renders a train unable to perform a monitored function. For a component degraded condition, "time of discovery" is when an evaluation is completed that determines that a train is/was unable to perform a monitored function. In both of these cases, train unavailability is assigned only for the time it takes to restore the ability to perform the monitored function(s) from the time the failure is known. In the case of a component degraded condition that renders a train unable to perform a monitored function, an appropriate type failure is assigned to the component in MSPI unreliability to account for the amount of time that the condition existed prior to discovery, when the component was in an unknown failed state.

Delays in initiating or completing evaluations of degraded conditions would be addressed through the inspection process.

If licensee and NRC resident/region do not agree on the facts and circumstances, explain
The licensee and the NRC agree on this change

Potentially relevant existing FAQ numbers
None

Response Section
If appropriate, provide proposed rewording of guidance for inclusion in next revision.

Change the guidance as follows:

- Page 29, section titled Indicator Definition, second paragraph, line 20. Add the following sentence after the last sentence (in the parentheses) of the second paragraph; "Time of discovery of a failed monitored component is when the licensee determines that a failure has occurred or when an evaluation determines that the train would not have been able to perform its monitored function(s)." In any case where a monitored component has been declared inoperable due to a degraded condition, if the component is considered available, there must be a documented basis for that determination, otherwise a failure will be assumed and unplanned unavailability would accrue. If the component is degraded but considered operable, timeliness of completing additional evaluations would be addressed through the inspection process.
- Page F-5, section titled "Actual Train Unavailability," paragraph starting "Unplanned unavailable hours:" After the first sentence of this paragraph add "Time of discovery of a failed monitored component is when the licensee determines that a failure has occurred or when an evaluation determines that the train would not have been able to perform its monitored function(s)." In any case where a monitored component has been declared inoperable due to a degraded condition, if the component is considered available, there must be a documented basis for that determination, otherwise a failure will be assumed and unplanned unavailability would accrue. If the component is degraded but considered operable, timeliness of completing additional evaluations – would be addressed through the inspection process.
- Page F-5, section titled "Actual Train Unavailability," paragraph starting "Unplanned unavailable hours:" In the third sentence on line 39, revise the sentence to read "oil leak that was determined to have resulted in the equipment being non-functional……"
- The background information above should be placed in a performance indicator basis document such as IMC 0308.