Enclosure 3
January 2010 Reactor Oversight Process (ROP)
Monthly Public Meeting Handouts
Dated 2/12/2010

(Existing) *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 failure was independent of the maintenance performed.)

(Proposed*) EDG failure to start*[1]*:* A failure to start includes those failures up to the point where the EDG output breaker has received a signal to close. (Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed.

*(*Existing*) EDG failure to load/run:* Given that it 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 failure was independent of the maintenance performed.)

(Proposed) *EDG failure to load/run*[1]*:* Given that it has successfully started, a failure of the EDG output breaker to close, ~~to successfully load sequence, and~~ or a failure to run/operate for one hour during surveillance test load sequencing or actual demand.~~ to perform its monitored functions.~~ The one hour clock starts at the time that the EDG output breaker closes. During surveillance testing the EDG may not be fully loaded.~~ at the end of the first hour.~~ ~~This failure mode is treated as a demand failure for calculation purposes.~~ Failure to load/run also includes failures of the EDG output breaker to re-close following a grid disturbance if the EDG was running paralleled to the grid. (Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed).

(Existing) *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 failure was independent of the maintenance performed.)

(Proposed*) EDG failure to run*[1]*:* Given that it has successfully started, the output breaker successfully closed, and the EDG has run for an hour after the output breaker closed, a failure of an EDG to run/operate. During surveillance testing the EDG may not be fully loaded. (Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed.)

Draft MS05 PI Report Date Whitepaper

<u>Problem</u>

Questions regarding Safety System Functional Failure (SSFF) reportability associated with several Licensee Event Reports (LER) submitted by multiple licensees has resulted in the submittal of several revised or corrected LERs in the same period to report previously unreported SSFFs. The sudden jump in the number of SSFFs reported has resulted in a sharply negative performance indicator (PI) trend for PI MS05. This translates into a false indication of equipment performance for the current reporting periods.

Two different sections of NEI 99-02 can be interpreted in ways that produce different PI results when dealing with the submission of revised LERs that report previously unreported SSFFs and correct SSFF PI data. The section of NEI 99-02 that addresses reporting of SSFFs defines the PI "reporting date" as the date the LER is submitted. However, the section of NEI 99-02 that addresses corrections to previously submitted data provides guidance to use the CDE change report to correct previous submitted data "only to the extent necessary to correctly calculate the indicator for the current reporting period." The current interpretation of the NEI 99-02 guidance, based on the most recent NRC feedback, requires plants to report the SSFF occurrences (SSFF PI data) when the revised LERs are submitted. This results in an indication that portrays a large number of SSFFs occurring at the plants in a relatively short period of time when, in actuality, the PI data being reported is an indication of incorrect reportability determinations – not current equipment performance.

The purpose of MS05 is to monitor events or conditions for which there was a reasonable expectation that the fulfillment of the safety function of structures or systems would have been prevented. The performance indicator measures the number of events over a 4 quarter period. Because actual LER report dates typically lag the event date by sixty days or more, the PI "reporting date" was initially defined to establish consistency in reporting PI data - there was no forethought given to the time lag associated with revised or corrected LERs. The current guidance in NEI 99-02 does not make a distinction between an original LER that is reporting a SSFF within the time limits permitted by regulation (i.e., within 60 days) and an LER that is being corrected or revised to report a SSFF (i.e., sometime between 60 days from the time of event and three years from the time of the event).

PI data that reports SSFF(s) from a corrected or revised LER results in an unintended consequence if the initial SSFF event occurred more than four quarters earlier because the PI starts counting events outside the 4 quarter PI period. Also, the failure to associate the SSFF with the time period in which it occurred risks masking declining performance that existed at the time. When this occurs, the PI essentially shifts from monitoring plant equipment performance (events or conditions that prevented, or could have prevented, the fulfillment of the safety function) to monitoring human performance (the ability of a licensee to correctly report SSFFs).

<u>Proposed Resolution</u>

Clarify NEI 99-02 to accommodate revised LERs that report previously unreported SSFFs to be applied retroactively.

<u>Proposed Rewording of Guidance</u>

Revise NEI 99-02 Rev 6, Page 29, Line 31 to read:

Reporting date: the date of the SSFF for PI reporting purposes is the report date of the initial LER. If an LER is revised and subsequently reports a SSFF, the SSFF for PI data reporting purposes is the date of the original LER. If due to an error, an LER was not previously submitted, the reporting date of the SSFF will be sixty days after the event. PI data shall be corrected in accordance with the guidance provided in the Introduction Section of NEI 99-02. In cases where the original LER was submitted earlier than the current four quarter PI period, no correction is made to the previously submitted PI data; however, a comment shall be included in the MS-05 section of the next PI data submittal. The comment shall indicate that an LER (<u>include number</u>) was submitted that reported a previously unreported SSFF that occurred on (<u>include event date of the original LER</u>) which was outside the current PI reporting period.

ITemp No.	PI	Topic	Status	Plant / Co.
09-06	EP01	Offsite Call Simulation	Discussed	DAEC
09-07	MSPI	Changes to Planned Unavailability Baseline	Tentative Approval	Generic
09-09	IE03	Unplanned Power Changes	Tentative Approval	Generic
09-10	EP02	Common EOF	Discussed	Sequoyah
10-01	NA	Withdrawal of FAQs	Introduced	Generic
10-02	IE04	USwC	Introduced	Generic

FAQ

Plant: Duane Arnold Energy Center
Date of Event: 6/24/09
Submittal Date: 7/21/09
Licensee Contact: Mike Davis, Bob Murrell
Tel/email: 319-851-7032/ michael.davis@nexteraenergy.com
319-851-7900/ robert.murrell@nexteraenergy.com
NRC Contact: Randy Baker Tel/email: 319-851-7210

Performance Indicator: **Drill and Exercise Performance**

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):

NEI 99-02, Rev. 6 page 45, lines 43 – 46:

> *Performance statistics from operating shift simulator training evaluations may be included in this indicator only when the scope requires classification. Classification, PAR notifications and PARs may be included in this indicator if they are performed to the point of filling out the appropriate forms and demonstrating sufficient knowledge to perform the actual notification.*

NEI 99-02, Rev. 6 page 46, lines 17 – 19:

> *Simulation of notification to offsite agencies is allowed. 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.*

Event or circumstances requiring guidance interpretation:

In accordance with Duane Arnold Energy Center (DAEC) procedures for making offsite notifications of emergency events, the Shift Technical Advisor (Key Communicator) fills out the notification form, gains approval from the Shift Manager (Key Decision Maker/Emergency Director), and hands the form off to the Security Shift Supervisor (not filling an NRC Participation PI key position). The Security Shift Supervisor then contacts offsite authorities using a telephone system (one call notifies all county and state authorities).

During licensed operator continuing training simulator evaluations, Security personnel are sometimes not available to participate. In these cases, the simulator instructor/evaluator role-plays as the Security Shift Supervisor. When this occurs, the instructor does not pick up the phone and simulate making a call to offsite authorities.

The NRC resident has challenged counting these as successful DEP opportunities because there is no demonstration of using the phone equipment.

NEI 99-02, Rev. 6 seems to differentiate the extent of demonstrating notification between operations simulator evaluations and drills. This is also discussed in a previous FAQ 202.

What extent of simulation is required to “demonstrate sufficient knowledge to perform actual notification”? Should “demonstration of their ability to use the equipment” be applied to operations simulator evaluations?

In the simulator evaluations in question, the simulator scenario was developed to have the instructor role-play as the Shift Security Supervisor and did not require any participant to demonstrate use of the phone if security personnel were not available. If these instances do not meet the intent for demonstrating sufficient knowledge of performing notifications and there were no errors made by the participants, should these opportunities be counted in the performance indicator as failures?

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

The NRC has concluded that the opportunities are failures due to not demonstrating the use of phone equipment.

Potentially relevant existing FAQ numbers

None

Response Section

Proposed Resolution of FAQ

During operator simulator training, personnel filling a non-key position for making a phone call to offsite agencies may not be available. In these instances where the Shift Manager (Emergency Director) and the Shift Communicator do not perform the notification phone call, it is acceptable to demonstrate the notification process up to the point of filling out the appropriate forms and providing the completed notification forms to a person role-playing as the phone-talker.

At a later time off sequence a phone talker will complete the process of using the telecommunications equipment.

Past opportunities performed by Licensees in a similar manner as the FAQ submitter will not require revision. Data will be collected using this new process going forward.

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

NEI 99-02, Rev. 6 page 45, lines 43 – 46:

Current wording is italicized, proposed additions are underlined.

Performance statistics from operating shift simulator training evaluations may be included in this indicator only when the scope requires classification. Classification, PAR notifications and PARs may be included in this indicator if they are performed to the point of filling out the appropriate forms and demonstrating sufficient knowledge to perform the actual notification. <u>It is recognized that key control room positions may not perform the actual communication with offsite agencies as part of the notification process. Personnel filling non-key positions for contacting offsite agencies (phone-talker) may not be available during simulator training. Therefore, “demonstrating sufficient knowledge” during the simulator session includes demonstrating knowledge of the notification process and interface with persons (actual or evaluator role-playing) assigned to contact offsite agencies using equipment (phone-talker). If an evaluator role-plays the phone talker during the simulator session, a phone talker is required to complete the notification process out of sequence (e.g. notification form completed in the simulator is provided to a phone talker at a later time and the phone talker demonstrates use of the telephone equipment). Timeliness is determined by adding the time</u>

required to complete the notification form in the simulator to the time required by the phone talker to utilize the communications equipment out of sequence.

FREQUENTLY ASKED QUESTION

Plant: N/A
Date of Event: N/A
Submittal Date: October 15, 2009
Licensee Contact: Roy Linthicum
NRC Contact: John Thompson, 301 415-1011, john.thompson@nrc.gov

Performance Indicator: Mitigating System Performance Indicator

Site-Specific FAQ? NO

FAQ requested to become effective: NA

__Question Section__

NEI guidance needing interpretation/revision:

NEI 99-02, Revision 5, Appendix F, Section F.1.2.1:

To address the problem of having too frequent baseline revisions, the staff is proposing to clarify the definition of maintenance program philosophy and the addition of a requirement to ensure that changes in the UA baseline are consistent with the unavailability assumptions contained in the PRA.

Basis for Revising NEI 99-02, Appendix F, Section f 1.2.1

Section F1.2.2 states that, "The initial baseline planned unavailability is based on actual plant-specific values for the period 2002 through 2004. (Plant specific values of the most recent data are used so that the indicator accurately reflects deviation from expected planned maintenance.) These values are expected to change if the plant maintenance philosophy is substantially changed with respect to on-line maintenance or preventive maintenance. In these cases, the planned unavailability baseline value should be adjusted to reflect the current maintenance practices, including low frequency maintenance evolutions." The point of changing the planned unavailability values is to account for philosophy changes to the on-line maintenance or preventive maintenance program.

As this UA baseline definition includes all non-failure activities, the concept of making changes to the UA baseline tied solely to the maintenance program philosophy appears to have created inconsistencies in the implementation of maintenance program philosophy changes. It is the staff's expectation that the performance or condition of the SSCs is effectively controlled by preventive maintenance and testing programs (a maintenance rule expectation). These programs and condition monitoring activities should be periodically evaluated to ensure that the objective of preventing failures of SSCs through maintenance is appropriately balanced against the objective of minimizing unavailability of SSCs. Changes to the maintenance program philosophy refer to changes to the preventive maintenance and testing programs. This interpretation is consistent with the definition of Maintenance contained in Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." This guidance states: "For the purposes of the maintenance rule, maintenance activities are as described in the "Final Commission Policy Statement on Maintenance of Nuclear Power Plants. This definition is very broad and includes all activities associated with the planning, scheduling, accomplishment, post-maintenance testing, and returning to service activities for surveillances and preventive and corrective maintenance." Other additions of unplanned unavailability, such as equipment modifications, except as discussed below, or responses to degraded conditions, are not considered to be a change in maintenance program philosophy. Changes to baseline unavailability for equipment modifications are allowed only if the modification is consistent with the assumptions in the PRA that were used to develop the MSPI Birnbaum values and are not already reflected in the MSPI UA baseline. That is, the unavailability values contained in the PRA include unavailability hours consistent with those needed for the proposed modification, and current maintenance and testing programs; and the hours in the MSPI UA baseline do not reflect this total unavailability. If the MSPI baseline is adjusted as a result of a modification, the MSPI baseline changes should be removed at the conclusion of the 3-year monitoring period that encompasses the modification.

The initial baseline planned unavailability is based on actual plant-specific values for the period 2002 through 2004 and may not be fully consistent with current practices. However, it is expected that changes to baseline unavailability will reflect the appropriate balancing of preventing failures of SSCs against the objective of minimizing unavailability of SSCs and, as such, the unavailability should not be increasing with time unless a maintenance program philosophy change has been implemented.

Event or circumstances requiring guidance interpretation:

Recommended Changes

Change Section F1.2.2 (lines 35 to 41) from:

The initial baseline planned unavailability is based on actual plant-specific values for the period 2002 through 2004. (Plant specific values of the most recent data are used so that the indicator accurately reflects deviation from expected planned maintenance. These values are expected to change if the plant maintenance philosophy is substantially changed with respect to on-line maintenance or preventive maintenance. In these cases, the planned unavailability baseline value should be adjusted to reflect the current maintenance practices, including low frequency maintenance evolutions.)

To:

The initial baseline planned unavailability is based on actual plant-specific values for the period 2002 through 2004. (Plant specific values of the most recent data are used so that the indicator accurately reflects deviation from expected planned maintenance. These values are expected to change if the plant maintenance philosophy is substantially changed with respect to on-line maintenance or preventive maintenance. In these cases, the planned unavailability baseline value should be adjusted to reflect the current maintenance practices, including low frequency maintenance evolutions.) Prior to implementation of an adjustment to the planned unavailability baseline value, the impact of the adjusted values on all MSPI PRA inputs should be assessed. A change to the PRA model and associated changes to the MSPI PRA inputs values is required prior to changing the baseline unavailability if:

$\Delta CDF > 1E\text{-}8$

Where:

$\Delta CDF_{baseline} = \sum(\Delta UA_i * Birnbaum_i)$

$\Delta UA_i = UA_{current} - UA_{baseline}$ for segment i

$UA_{current}$ = proposed unavailability (expressed as a probability) to be used as the new baseline

$UA_{baseline}$ = the base unavailability (expressed as a probability) for 2002 – 2004

$Birnbaum_i$ = Birnbaum value of segment i

The following changes are considered a "change in plant maintenance philosophy:"

- A change in frequency or scope of a current preventative maintenance activity or surveillance test.
- The addition of a new preventative maintenance activity or surveillance test.
- The occurrence of a periodic maintenance activity at a higher or lower frequency during a three year data window (e.g., a maintenance overhaul that occurs once every 24 months will occur twice 2/3 of the time and once 1/3 of the time). If the unavailability hours required for the additional maintenance activity is included in the PRA modeled unavailability, the baseline unavailability can be changed without further assessment.
- Planned maintenance activities that occur less than once every 3 years (e.g., 5 or 10 year overhauls). If the unavailability hours required for the additional maintenance activity is included in the PRA modeled unavailability, the baseline unavailability can be changed without further assessment.
- The performance of maintenance in response to a condition-based preventive maintenance activity.
- Performance of an on-line modification that has been determined to be consistent with the unavailability values contained in the PRA in that the PRA includes unavailability hours for the proposed modification, and current maintenance and testing programs; and the hours in the MSPI UA baseline do not reflect this total unavailability.

The following changes are not considered a "change in plant maintenance philosophy:"

- The performance of maintenance in response to a degraded condition (even when it is taken out of service to address the degraded condition) unless this action is in response to a condition-based preventive maintenance activity.
- Planned maintenance activity that exceeds its planned duration.
- The performance of an on-line modification that do not meet the change in plant maintenance philosophy online modification criterion.

Note: Condition-based maintenance consists of periodic preventive maintenance tasks or on-line monitoring of the health or condition of a component (e.g., vibration analysis, oil analysis, MOVAT) and predefined acceptance criteria where corrective action is to be taken on exceeding these criteria. Condition-based maintenance does not include discovery of a degraded condition as a result of actions that are outside of the maintenance programs.

Plant: N/A
Date of Event: N/A
Submittal Date: October 15, 2009
Licensee Contact: Jeff Thomas, 704-382-3438, cjthomas@duke-energy.com
NRC Contact: John Thompson, 301 415-1011, john.thompson@nrc.gov

UNPLANNED POWER CHANGES PER 7,000 CRITICAL HOURS

Purpose

This indicator monitors the number of unplanned power changes (excluding scrams) that could have, under other plant conditions, challenged safety functions. It may provide leading indication of risk-significant events but is not itself risk-significant. The indicator measures the number of plant power changes for a typical year of operation at power.

Indicator Definition

The number of unplanned changes in reactor power greater than 20% of full-power, per 7,000 hours of critical operation excluding manual and automatic scrams.

Data Reporting Elements

The following data is reported for each reactor unit:

- the number of unplanned power changes, excluding scrams, during the previous quarter
- the number of hours of critical operation in the previous quarter

Calculation

The indicator is determined using the values reported for the previous 4 quarters as follows:

$$value = \frac{(total\ number\ of\ unplanned\ power\ changes\ over\ the\ previous\ 4\ qtrs)}{total\ number\ of\ hours\ critical\ during\ the\ previous\ 4\ qtrs} x\ 7{,}000\ hrs$$

Definition of Terms

Unplanned ~~change~~ change in reactor power, for the purposes of this indicator, is a change in reactor power that (1) ~~was~~ was initiated less than 72 hours following the discovery of an off-normal condition that required or ~~resulted~~ resulted in a power change of greater than 20% full power to resolve and (2) has not been excluded ~~from~~ from counting per the guidance below. Unplanned changes in reactor power also include uncontrolled excursions of greater than 20% of full power that occur in response to changes in reactor or plant conditions and are not an expected part of a planned evolution or test.

Formatted: Space Before: 6 pt

Clarifying Notes

The value of 7,000 hours is used because it represents one year of reactor operation at about an 80% availability factor.

If there are fewer than 2,400 critical hours in the previous four quarters the indicator value is displayed as N/A because rate indicators can produce misleadingly high values when the denominator is small. The data elements (unplanned power changes and critical hours) are still reported.

The 72 hour period between discovery of an off-normal condition and the corresponding change ~~in power level of greater than 20% of full power to resolve and the corresponding change~~ in power level is based on the typical time to assess ~~prepare for a planned power change. It includes 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 the planning that is performed between the discovery of the condition and initiation of the power change.

~~recognizing the possible need for a change in power level of greater than 20% and completion of the power change. The licensee should have objective evidence to demonstrate when the possible need for the downpower was recognized such as logs documenting actions required by Technical Specifications, troubleshooting plans, meeting minutes, corrective action program entries, or similar type documentation.~~
Given the above, it is incumbent upon licensees to provide objective evidence that identifies when the off-normal condition was discovered and when the power change of more than 20% was initiated. Such objective evidence may include logs, troubleshooting plans, meeting minutes, corrective action program documents, or similar type documentation.

Examples of occurrences that would be counted against this indicator include:

- Power reductions that exceed 20% of full power and are not part of a planned and documented evolution or test. Such power changes may include those conducted in response to equipment failures or personnel errors or those conducted to perform maintenance.
- Runbacks and power oscillations greater than 20 % of full power. A power oscillation that results in an unplanned power decrease of greater than 20% followed by an unplanned power increase of 20% should be counted as two separate PI events, unless the power restoration is implemented using approved procedures. For example, an operator mistakenly opens a breaker causing a recirculation flow decrease and a decrease in power of greater than 20%. The operator, hearing an alarm, suspects it was caused by his action and closes the breaker resulting in a power increase of greater than 20%. Both transients would count since they were the result of two separate errors (or unplanned/non-proceduralized action).
- Unplanned downpowers of greater than 20% of full power for ALARA reasons

Formatted: Bulleted + Level: 1 + Aligned at: 18 pt + Tab after: 0 pt + Indent at: 36 pt

Examples of occurrences that are not counted include the following:

- Planned power reductions (anticipated and contingency) that exceed 20% of full power and are initiated in response to an off-normal condition discovered at least 72 hours before initiation of the power change.
- Unanticipated equipment problems that are encountered and repaired during a planned power reduction greater than 20% that alone could have required a power reduction of 20% or more to repair.
- Apparent power changes that are determined to be caused by instrument problems.
- If conditions arise that would normally require unit shutdown, and an NOED is granted that allows continued operation before power is reduced greater than 20%, an unplanned power change is not reported because no actual change in power greater than 20% of full power

Formatted: Bulleted + Level: 1 + Aligned at: 18 pt + Tab after: 0 pt + Indent at: 36 pt occurred. However, 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.

- Anticipatory power reductions intended to reduce the impact of external events such as hurricanes or range fires threatening offsite power transmission lines, and power changes requested by the steam load dispatches.
- Power changes to make rod pattern adjustments
- Power changes directed by the load dispatcher under normal operating conditions due to load demand, for economic reasons, for grid stability, or for nuclear plant safety concerns.

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 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.

Formatted: Space Before: 0 pt, No bullets or numbering

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.

Formatted: No bullets or numbering

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 however, the condition suddenly degrades beyond the predefined limits and requires rapid response, this situation would count. If the licensee has previously identified a slowly degraded off-normal condition but has not prepared plans recognizing the potential need to reduce power when the condition reaches predefined limits, then a sudden degradation of that condition requiring rapid response would constitute a new off-normal condition and therefore, a new time of discovery.

Formatted: No bullets or numbering

Formatted: Font color: Auto

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. However, if the cause of the downpower(s) and the scram are different, an unplanned power change and an unplanned scram must both be counted. For example, an unplanned power reduction is made to take the turbine generator off line while remaining critical to repair a component. However, when the generator is taken off line, vacuum drops rapidly due to a separate problem and a scram occurs. In this case, both an unplanned power change and an unplanned scram would be counted. If an off-normal condition occurs above 20% power, and the plant is shutdown by a planned reactor trip using normal operating procedures, only an unplanned power change is counted.

FAQ TEMPLATE

Plant: Plant Generic

Date of Event: 10/19/2009
Submittal Date: 11/09/2009
Licensee Contact: Tony Feltman Tel/email: ahfeltman@tva.gov
Martin Hug mth@nei.org
NRC Contact: Tel/email:

Performance Indicator: NEI 99-02 (rev. 6) 2.4 Emergency Preparedness Cornerstone Emergency Response Organization Drill Participation

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):

Page 50, Lines 3-8

Purpose

This indicator tracks the participation of ERO members assigned to fill Key Positions in performance enhancing experiences, and through linkage to the DEP indicator ensures that the risk significant aspects of classification, notification, and PAR development are evaluated and included in the PI process. This indicator measures the percentage of ERO members assigned to fill Key Positions who have participated recently in **performance-enhancing experiences** such as drills, exercises, or in an actual event.

Page 50, Lines 10 - 13
Indicator Definition
The percentage of ERO members assigned to fill Key Positions that have participated in a drill, exercise, or actual event during the previous eight quarters, **as measured on the last calendar day of the quarter.**

Page 50, Lines 13 - 14
If an ERO member filling a Key Position has participated in more than one drill during the eight quarter evaluation period, the most recent participation should be used in the indicator statistics.

Page 52, Lines 20-22
If a person is assigned to more than one Key Position, it is expected that the person be counted in the denominator for each position and in the numerator only for drill participation that addresses each position. **Where the skill set is similar**, a single drill might be counted as participation in both positions.

Page 52, Lines 24-29
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; particularly, if more than one ERO position is assigned to perform the same Key Position.

Page 52, Lines 31-41
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 that ERO member and credit given in the numerator when the ERO member performs each Key Position.

Similarly, ERO members **need not individually** perform an opportunity of classification, notification, or PAR development in order to receive ERO Drill Participation credit. The evaluation of the DEP opportunities is a crew evaluation for the entire Emergency Response Organization. ERO members may receive credit for the drill if their participation is a meaningful opportunity to gain proficiency in their ERO function.

Page 53, Lines 1-3
Participation may be as a participant, mentor, coach, evaluator, or controller, but not as an observer. Multiple assignees to a given Key Position could take credit for the same drill if their participation is a meaningful opportunity to gain proficiency.

Event or circumstances requiring guidance interpretation:
The event/circumstance principally involves utilities with common EOFs where the functions of EOF Senior Manager, EOF Key Protective Measures and EOF Communicator are assigned to Key Positions that generically support multiple nuclear sites.

Utilities with a common EOF established to support multiple nuclear sites have made Key Position assignments to provide implementation of the three functions mentioned above and described in NEI 99-02 rev 6.

ERO members assigned to each function are grouped and monitored to ensure that each member receives a "meaningful opportunity to gain proficiency". This membership is accounted for at the end of each quarter and entered into the ROP process.

Where common EOFs are established supporting multiple sites the EOF, ERO membership is trained, including involvement in a drill and exercise program to ensure that they are fully qualified to respond to each site served by that EOF when emergencies are declared.

To restate the issue another way, this membership represents each nuclear site served by the EOF operationally and functionally.

In general given this prescribed condition procedures, processes and protocols have been established that have generic application or in words the **skill set is similar** in application regardless of the nuclear site involved.

Where benchmarking has been conducted, a common approach to calculating Participation Credit for this EOF Key Position set is as follows;

Participation Credit is given for these "generic" key positions and counted (as specified in NEI 99-02) for all nuclear sites served by the EOF when a Key Position member is provided a meaningful opportunity to gain proficiency during any one nuclear site drill or exercise. This practice is not a new practice nor is this practice the result of a collaborative effort. This has been establish by each utility separately.

Comment [MTH1]: NRC does not believe 99-02 invokes this process so I do not want to draw attention to this point.

DEP Credit is only provided to the nuclear site included in the drill or exercise additionally as invoked by NEI 99-02.

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

NRC region does not agree with the generic participation credit approached and has specified that participation credit can ONLY be provided to the specific site involved in the drill or exercise.

Potentially relevant existing FAQ numbers

NA

<u>Response Section</u>

Proposed Resolution of FAQ

1) Revise NEI 99-02 to provide clarifying language to more effectively communicate counting participation credit for NEI 99-02 EOF positions when centralized Emergency Offsite Facilities are utilized.
2) The concept of a centralized Emergency Offsite Facility was being utilized prior to the issuance of NEI 99-02 at a minimum of three utilities. Tennessee Valley Authority, Exelon and the Salem-Hope Creek facility each had centralized Emergency Offsite Facilities. Additionally Exelon executed a pilot for NEI 99-02 where participation credit was counted for each plant served by the centralized Emergency Offsite Facility.

If appropriate, provide proposed rewording of guidance for inclusion in next revision.
[PARTICIPATION]
NEI 99-02 Revision 6, page 54

expected to be just a phone talker who is not tasked with filling out the form. There is no intent to track a large number of shift communicators or personnel who are just phone talkers.

Where an approved centralized Emergency Offsite Facility (EOF) serves multiple nuclear plant sites at a number of locations (fleet concept) participation may be counted for each of the nuclear sites served by the centralized EOF when;

- Key EOF Positions are functionally aligned as prescribed in NEI 99-02.
- Key EOF Positions support similar key skills and functions
  - When only site specific attributes (i.e., evacuation sections, EALs, etc.) differ but the key skills and functions to attain the attributes are similar then participation credit may be counted.
- All other NEI 99-02 criteria for participation are met.
- Specifically the following criteria shall be met to grant participation credit:
  - Dose assessment – same software used for all sites.
  - Field monitoring team tracking and control are the same if EOF directs teams. Radio systems are the same.
  - PAR process is the same.
  - Notification form and equipment the same.
  - There are advisors on each team in the EOF that are familiar with each plant so that the EOF Senior Manager and EOF Key Protective Measures ERO Member may be advised on EALs, site terrain and special weather condition attributes, plant operation (BWR and PWR experience) and radiation monitoring system characteristics.

[DRILL AND EXERCISE PERFORMANCE]
NEI 99-02 Revision 6, page 48

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.

If a licensee discovers after the fact (greater than 15 minutes) that an event or condition had existed which exceeded an EAL, but no emergency had been declared and the EAL is no longer exceeded at the time of discovery, the following applies:

- *If the indication of the event was not available to the operator, the event should not be evaluated for PI purposes.*
- *If the indication of the event was available to the operator but not recognized, it should be considered an unsuccessful classification opportunity.*

- *In either case described above, notification should be performed in accordance with*

NUREG-1022 and not be evaluated as a notification opportunity.

Where an approved centralized Emergency Offsite Facility (EOF) serves multiple nuclear plants sites at a number of locations (fleet concept) DEP for any drill or exercise may be only counted for the participating nuclear sites served by the centralized EOF and principally involved in actual or simulated emergency event.

FAQ TEMPLATE

Plant: _Generic_________________
Date of Event: __NA__________________
Submittal Date: __January 21, 2010 _________
Licensee Contact: __Ken Heffner________ Tel/email: _919-270-5611/kmh@nei.org
NRC Contact: __Nathan Sanfiilipo____ Tel/email: _301-415-3951/nathan.sanfillipo@nrc.gov

Performance Indicator:

NA

Site-Specific FAQ (Appendix D)? No

FAQ requested to become effective when approved

Question Section

Existing Guidance on Page E-3 beginning at line 16

Withdrawal of FAQs

A licensee may withdraw a FAQ after it has been accepted by the joint ROP Working Group. Withdrawals must occur during an ROP Working Group monthly (approximately) meeting. However, the ROP Working Group should further discuss and decide if a guidance issue exists in NEI 99-02 that requires additional clarification. If additional clarification is needed then the original FAQ should be revised to become a generic FAQ.

Event or circumstances requiring guidance interpretation

The staff has expressed concern that when a licensee withdraws an FAQ, the efforts that they expend during the discussions preceding the withdrawal of the FAQ are not captured.

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

NA

Response Section

Proposed Resolution of FAQ

Recommended Change

Withdrawal of FAQs

A licensee may withdraw a FAQ after it has been accepted by the joint ROP Working Group. Withdrawals must occur during an ROP Working Group meeting. However, the ROP Working Group should further discuss and decide if a guidance issue exists in NEI 99-02 that requires additional clarification. If additional clarification is needed then the original FAQ should be revised to become a generic FAQ. In many cases, there are lessons learned from the resources expended by the ROP Working Group that should be captured. In those cases, the FAQ will be entered in the FAQ log as a generic FAQ. If there is disagreement between the staff and industry, both positions should be articulated in the FAQ. These withdrawn FAQs should be considered as historical and are not considered to be part of NEI 99-02. Although they do not establish precedence, they do offer insights into perspectives of both industry and NRC staff and, as such, can inform future decisions to submit an FAQ.

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

See proposed resolution

FAQ TEMPLATE

Plant: _Generic_________________
Date of Event: __NA___________________
Submittal Date: __January 21, 2010 _________
Licensee Contact: __Ken Heffner________ Tel/email: _919-270-5611/kmh@nei.org
NRC Contact: __Nathan Sanfiilipo____ Tel/email: _301-415-3951/nathan.sanfillipo@nrc.gov

Performance Indicator:
IE04 Unplanned Scrams with Complications

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):

NEI 99-02 Revision 6, Page 20 lines 22 to 46, page 22 lines 35-45, and page 23 lines 1-10 discuss whether or not Main Feedwater was available following an unplanned scram.

Event or circumstances requiring guidance interpretation:

When FAQ # 467 was approved, the response section stated that the guidance in NEI 99-02 should be reviewed to see if it needs to be revised based on circumstances that might require the availability of feedwater beyond 30 minutes and whether consideration of the scram response time window remains an appropriate marker for judging a complication to recovery from an unplanned scram.

The purpose of this FAQ is to define what constitutes scram“ response” as opposed to scram “recovery.”

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

In FAQ #467, the plant’s recommendation was to change the guidance in two locations:

1. If operating prior to the scram, did Main Feedwater cease to operate and was it unable to be restarted during the reactor scram response? The consideration for this question is whether Main Feedwater could be used to feed the reactor vessel if necessary. When considering the availability of Main Feedwater, it should be able to be restarted within the first 30 minutes following the scram.

The Senior Resident’s response was that this guidance change would not capture those events that are of higher safety significance because main feed is not available, even if it was not required to be used, and 30 minutes is a completely arbitrary number.

2. Operations should be able to start a Main Feedwater pump and start feeding the reactor vessel with the Main Feedwater System within 30 minutes of the initial scram transient. During startup

conditions where Main Feedwater was not placed in service prior to the scram, the question would not be considered, and should be skipped.

This Senior Resident's response to this proposed change was that even if the main feed steam supply is temporarily isolated, the PI should capture those events where main feed couldn't be restored in a relatively short time. "It might be different if the equipment was designed such that restoration was not possible

Potentially relevant existing FAQ numbers
467

Response Section

Proposed Resolution of FAQ

The first 30 minutes after the scram is considered scram response and Main Feedwater must be available in the event that it could be needed. After 30 minutes is considered scram recovery.

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