Enclosure 2
Meeting Summary Handouts
of the March 30, 2011
ROP Public Meeting
Dated April 13, 2011

REACTOR OVERSIGHT PROCESS (ROP)
MONTHLY PUBLIC MEETING AGENDA

March 30, 2011; 9:00 AM – 2:30 PM; Two White Flint North Building;
ACRS Conference Room – T-2B1

9:00 – 9:05 AM	Introduction and Purpose of Meeting
9:05 – 9:15 AM	Inspection Branch Topics 1. General operating experience topics of interest 2. Opportunity for public comment
9:15 – 9:25 AM	Operating Experience Branch Topics 1. General inspection topics of interest 2. Opportunity for public comment
9:25 – 9:35 AM	Performance Assessment Branch Topics 1. General assessment topics of interest 2. Opportunity for public comment
09:35 – 11:00 AM	Discussion of Performance Indicator (PI) Topics 1. Potential NEI 99-02 guidance changes • MSPI EDG boundary conditions (FOTP modeled as a separate component) • Discussion of Gap Analysis of the ROP 2. Opportunity for public comment
11:00 – 11:45 AM	Lunch
11:45 – 2:15 PM	Discussion of Open and New PI Frequently Asked Questions (FAQs) *Note: Topic may be moved up if meeting is ahead of schedule. The latest draft FAQs is located on the public web at: http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/draft_faqs.pdf. This list is subject to change the day before the meeting based on availability of new draft FAQs provided by the Nuclear Energy Institute. Public comments will be addressed on FAQs following the discussion.*
2:15 – 2:30 PM	Future Meeting Dates, Action Items, Future Agenda Topics

Breaks will be taken as needed

Open FAQs on NEI 99-02
Status Date: For 3/30/2011 ROP Public Meeting

No.	PI	Topic	Status	Plant/Co.	Point of Contact
09-10 FINAL	EP02	Common EOF	Discussed status 9/15/10. Proposed resolution is to be discussed 1/20/11. Updated text was provided to NRC (Kahler, et.al.) on 1/14/11 and, we believe, captures agreements of NSIR and EOP Task Force reached since 9/15/10. Revised text and current status was presented on 2/16/2011, per Marty Hug and Eric Schrader. *Tentatively Approved 1/20/11; Approved FINAL 2/16/11.* *Revised wording of FINAL version was sent to S. Vaughn for NRC approval notation on 3/8/11. NRC approval notation received week of 3/20.*	Generic	Walt Lee (TVA), Marty Hug (NEI)
10-02 To be discussed 3/30	IE04	USwC	NRC feedback on the last mark-up was received on 1/19/11. NRC's revised mark-up of NEI 99-02 will be discussed. *[Discussed 1/20, 2/16]*	Generic	Jim Slider (NEI)for the ROP Task Force
10-06 Not ready for discussion on 3/30	MS	Cascading Unavailability	Introduced at October 20 ROP meeting. Discussed 12/1/10. NRC to provide feedback at 1/20/11 meeting. NRC's proposed mark-up of NEI 99-02 will be discussed. *[Tentatively Approved 1/20/11; ROP TF proposed adjustments to NEI 99-02 will be ready for submittal to NRC at next meeting (May 2011)]*	Generic	John Dowling (Ameren)

Open FAQs on NEI 99-02
Status Date: For 3/30/2011 ROP Public Meeting

No.	PI	Topic	Status	Plant/Co.	Point of Contact
10-07 To be discussed 3/30	IE04	Vendor EOPs	Introduced at December 1 ROP meeting. ROP TF discussion draft of changes to NEI 99-02 will be presented. *[No discussion of contents 1/20, 2/16]*	Generic	Steve Vaughn (NRC)
11-01 To be discussed 3/30	MS10	Cooling Water Boundary	Converted from white paper to draft FAQ. FAQ to be introduced at 1/20/11 meeting. Revised wording from ROP TF will be discussed 3/30/2011. *[Introduced and discussed 1/20, 2/16]*	Generic	Jim Peschel (NextEra) Steve Vaughn (NRC)
11-02 FINAL	MS	MSPI Basis Document Updates	Converted from white paper to draft FAQ. FAQ to be introduced at 1/20/11 meeting. ROP TF revised wording will be presented 2/16/2011. *[Tentatively Approved 1/20, Final 2/16; NRC approval notation received]*	Generic	Roy Linthicum (Exelon) Steve Vaughn (NRC)
11-03 FINAL	USwC	Robinson Scram	Introduced 1/20/2011. *[Introduced, discussed and Tentatively Approved 1/20/11; Final 2/16; NRC approval notation received]*	Generic	Garrett Sanders (Progress)
11-04 To be discussed 3/30	IE03	Power Changes Needed to Recover from Loss of Equipment	Converted from white paper to draft FAQ. Introduced at 1/20/11 meeting. *[Introduced and discussed 1/20, 2/16]*	Generic	Robin Ritzman (First Energy) Jocelyn Lian (NRC)
11-05 To be discussed 3/30	MS08	Point Beach Pumps	Introduced 1/20/2011. *[Introduced, discussed and Tentatively Approved 1/20/11; further discussed 2/16]*	NextEra	Carol Jilek (NextEra)

Open FAQs on NEI 99-02
Status Date: For 3/30/2011 ROP Public Meeting

No.	PI	Topic	Status	Plant/Co.	Point of Contact
11-06 To be approved Final 3/30	MS	EDG Run Hours	Introduced 2/16/2011; tentatively approved 2/16.	Generic	Roy Linthicum (Exelon)
11-07 (Proposed)	MS	FOTP Failures	To be introduced 3/30/2011	Generic	Roy Linthicum (Exelon)
11-08 (Proposed)	MS	EDG Failure Mode Definitions	To be introduced 3/30/2011	Generic	Roy Linthicum (Exelon)

NEI Contact: James E. Slider, 202-739-8015, jes@nei.org

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 Sanfillipo____ 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.

UNPLANNED SCRAMS WITH COMPLICATIONS (USwC)

Purpose

This indicator monitors that subset of unplanned automatic and manual scrams that either require additional operator actions beyond that of the "normal" scram or involve the unavailability or inability to recover main feedwater. Such events or conditions have the potential to present additional challenges to the plant operations staff and therefore, may be more risk-significant than uncomplicated scrams.

Indicator Definition

The USwC indicator is defined as the number of unplanned scrams while critical, both manual and automatic, during the previous 4 quarters that require additional operator actions or involve the unavailability or inability to recover main feewater as defined by the applicable flowchart (Figure 2) during the scram response (see definition of *scram response* in the Definitions of Terms section)~~and the associated flowchart questions~~.

Data Reporting Elements

The following data are required to be reported for each reactor unit.

The number of unplanned automatic and manual scrams while critical in the previous quarter that required additional operator actions~~response~~ or involve the unavailability or inability to recover main feedwater as determined by the applicable flowchart ~~criteria~~(Figure 2) during the scram response.

Calculation

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

value = total unplanned scrams while critical in the previous 4 quarters that required additional operator ~~response~~ actions or involve the unavailability or inability to recover main feedwater as defined by the applicable flowchart ~~and the associated flowchart questions~~(Figure 2) during the scram response.

Definition of Terms

Scram means the shutdown of the reactor by the rapid addition of negative reactivity by any means, e.g., insertion of control rods, boron, use of diverse scram switches, or opening reactor trip breakers.

Normal Scram means any scram that is not determined to be complicated in accordance with the guidance provided in the Unplanned Scrams with Complications indicator. A normal scram is synonymous with an uncomplicated scram.

Unplanned scram means that the scram was not an intentional part of a planned evolution or test as directed by a normal operating or test procedure. This includes scrams that occurred during the execution of procedures or evolutions in which there was a high chance of a scram occurring but the scram was neither planned nor intended.

Criticality, for the purposes of this indicator, typically exists when a licensed reactor operator declares the reactor critical. There may be instances where a transient initiates from a subcritical condition and is terminated by a scram after the reactor is critical—this condition would count as a scram.

Scram Response refers to the period of time which starts with the onset of the initiating event and concludes when operators have~~-~~ completed the scram response EOP~~ actions~~ and the plant has achieved a stabilized condition in accordance with criteria in approved plant procedures.

For a PWR, the reactor is considered "stable" when all of the following are true:

- Pressurizer pressure is within the nominal operating pressure band
- Pressurizer level is within the no-load pressurizer band
- L~~The l~~evel and pressure of all steam generators is ~~between the bottom of the narrow range indication and 50%, including allowances for channel accuracies and reference leg process errors~~within the normal operating band. ~~and pressure is within the nominal operating pressure band.~~
- ~~The~~ RCS temperature is within the allowable RCS no-load temperature band (T_{ave} if any RCS pump running, T_{cold} if no RCS pumps running).
- [SJV1]

For a BWR, the reactor is considered stable when all of the following are true:

- No EOP entry conditions exist[s2]
- Reactor cooldown rates are less than 100 degrees F/hr
- Reactor water level is~~and pressure are~~ being maintained within the range specified by plant procedures

Clarifying Notes

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PWR FLOWCHART QUESTIONS (See Figure 2)
Did two or more control rods fail to fully insert?

…

Did the turbine fail to trip?

…

Was power lost to any ESF bus?

…

Was a Safety Injection signal received?

…

Was Main Feedwater unavailable or not recoverable using approved plant procedures ~~following the scram~~during the scram response?

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 steam generators if necessary. The qualifier of "not recoverable using approved plant procedures" will allow a licensee to answer "No" to this question if there is no physical equipment restraint to prevent the operations staff from starting the necessary equipment, aligning the required systems, or satisfying required logic using plant procedures approved for use and in place prior to the reactor scram occurring.

The operations staff must be able to start and operate the required equipment using normal alignments and approved emergency, normal, and off-normal operating procedures to provide the required flow to~~feed~~ the minimum number of steam generators required by the EOPs~~ to satisfy the heat sink criteria~~. Manual operation of controllers/equipment, even if normally automatic, is allowed if addressed by procedure. Situations that require maintenance or repair activities or non-proceduralized operating alignments require an answer of "Yes." Additionally, the restoration of Feedwater must be capable of feeding the Steam Generators in a reasonable period of time. Operations should be able to start a Main Feedwater pump and start feeding Steam Generators with the Main Feedwater System within about 30 minutes ~~post scram~~from the time it was recognized that Main Feedwater was needed. During startup conditions where Main Feedwater was not placed in service prior to the scram this question would not be considered and should be skipped. If design features or procedural prohibitions prevent restarting Main Feedwater under certain plant conditions, and MFW is free from damage or failure (i.e., capable of performing its intended function) and available for use, this question should be answered as "No."

Was the scram response procedure unable to be completed without entering another EOP?

…

BWR FLOWCHART QUESTIONS (See Figure 2)

Did an RPS actuation fail to indicate / establish a shutdown rod pattern for a cold clean core?

…

Was pressure control unable to be established following the initial transient?

…

Was power lost to any Class 1E Emergency / ESF bus?

…

Was a Level 1 Injection signal received?

…

Was Main Feedwater not available or not recoverable using approved plant procedures during the scram response?

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. The qualifier of “not recoverable using approved plant procedures” will allow a licensee to answer “NO” to this question if there is no physical equipment restraint to prevent the operations staff from starting the necessary equipment, aligning the required systems, or satisfying required logic circuitry using plant procedures approved for use that were in place prior to the scram occurring.

The operations staff must be able to start and operate the required equipment using normal alignments and approved emergency, normal and off-normal operating procedures. Manual operation of controllers/equipment, even if normally automatic, is allowed if addressed by procedure. Situations that require maintenance or repair activities or non-proceduralized operating alignments will not satisfy this question. Additionally, the restoration of Main Feedwater must be capable of being restored to provide feedwater to the reactor vessel in a reasonable period of time. Operations should be able to start a Main Feedwater pump and start feeding the reactor vessel with the Main Feedwater System within about 30 minutes from the time it was recognized that Main Feedwater was needed~~post scram~~. During startup conditions where Main Feedwater was not placed in service prior to the scram, this question would not be considered, and should be skipped.

Following initial transient, did stabilization of reactor pressure/level and drywell pressure meet the entry conditions for EOPs?

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Mark-up from Steve Vaughn 1/28/2011
For FAQ 10-02

APPENDIX H

USwC Basis Document

The USwC PI will monitor the following six conditions that either have the potential to complicate the operators' scram ~~recovery~~ response actions or involve the unavailability or inability to recover main feedwater during the scram response.

1. Reactivity Control
2. Pressure Control (BWRs)/Turbine Trip (PWRs)
3. Power available to Emergency Busses
4. Need to actuate emergency injection sources
5. Availability of Main Feedwater
6. Utilization of scram recovery Emergency Operating Procedures (EOPs)

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H 1 PWR Flowchart Basis Discussion

H 1.1 Did two or more control rods fail to fully insert?

…

H 1.2 Did the turbine fail to trip?

…

H 1.3 Was power lost to any ESF bus?

…

H 1.4 Was a Safety Injection signal received?

…

H 1.5 Was Main Feedwater unavailable or not recoverable using approved plant procedures ~~following the scram~~during the scram response?

This section of the indicator is a holdover from the Scrams with Loss of Normal Heat Removal indicator which the USwC indicator~~ is~~ replaced~~ing~~. Since all PWR designs have an emergency Feedwater system that operates if necessary, the availability of the normal or main Feedwater system,~~s~~ as~~is~~ a backup in emergency situations, can be important for managing risk following a reactor scram. This portion of the indicator is designed to

~~measure~~ assess that backup availability or ability to recover main feedwater as directed by approved plant procedures (e.g., the EOPs) on a loss of all emergency Feedwater.

It is not necessary for the main Feedwater system to continue operating following a reactor trip. Some plants, by design, have certain features to prevent main feedwater from continued operation or from allowing it to be restarted unless certain criteria are met. ~~The system must be free from damage or failure that would prohibit restart of the system if necessary.~~ Since some plant designs do not include electric driven main Feedwater pumps (steam driven pumps only) it may not be possible to restart main Feedwater pumps without a critical reactor. ~~Those plants should answer this question as "No" and move on.~~ ~~Some~~ Additionally, some other plant designs have interlocks and signals in place to prevent feeding the steam generators with main Feedwater unless reactor coolant temperature is greater than the no-load average temperature. In both cases these plants ~~should also answer this question as "No" and move on~~may be justified in answering this question as "No" if main feedwater is free from damage or failure (i.e., capable of performing its intended function) and available for use.

Licensees should rely on the material condition availability of the equipment to reach the decision for this question. Condenser vacuum, cooling water, and steam pressure values should be evaluated based on the requirements to operate the pumps and may be lower than normal if procedures allow pump operation at that lower value. As long as these support systems are able to be restarted (if not running) to support main feedwater restart within the estimated 30 minute timeframe they can be considered as available. These requirements apply until the completion or exit of the scram response. ~~procedure.~~

The availability of steam dumps to the condenser does NOT enter into this indicator at all. Use of atmospheric steam dumps following the reactor trip is acceptable for any duration.

Loss of one feed pump does not cause a loss of main feedwater. Only one is needed to remove residual heat after a trip. As long as at least one pump can still operate and provide Feedwater to the minimum number of steam generators required by the EOPs to satisfy the heat sink criteria, main feedwater should be considered available.

The failure in a closed position of a feedwater isolation valve to a steam generator is a loss of feed to that one steam generator. As long as the main feedwater system is able to feed the minimum number of steam generators required by the EOPs to satisfy the heat sink criteria, the loss of ability to feed other steam generators should not be considered a loss of feedwater. Isolation of the feedwater regulating or isolation valves does not constitute a loss of feedwater if nothing prevents them from being reopened in accordance with procedures.

A Steam Generator Isolation Signal or Feedwater Isolation Signal does not constitute a loss of main feedwater as long as it can be cleared and feedwater restarted. If the isolation signal was caused by a high steam generator level, the 30 minute estimate for restart time frame should start once the high level isolation signal has cleared.

The estimated 30 minute time frame for restart of main Feedwater was chosen based on restarting from a hot and filled condition. Since this time frame will not be measured directly it should be an estimation developed based on the material condition of the plants systems following the reactor trip. If no abnormal material conditions exist the 30 minutes should be met. If plant procedures and design would require more than 30 minutes, even if all systems were hot and the material condition of the plants systems following the reactor trip were normal, that routine time should be used in the evaluation of this question, provided SG dry-out cannot occur on an uncomplicated trip if the time is longer than 30 minutes. The ~~opinion~~ judgment of the on-shift licensed SRO during the reactor trip should be ~~accepted~~ used in determining if this timeframe was met.

H 1.6 Was the scram response procedure unable to be completed without entering another EOP?

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H 3 BWR Flowchart Basis Discussion

H 3.1 Did an RPS actuation fail to indicate / establish a shutdown rod pattern for a cold clean core?

…

H 3.2 Was pressure control unable to be established following the initial transient?

…

H 3.3 Was power lost to any Class 1E Emergency / ESF bus?

…

H 3.4 Was a Level 1 Injection signal received?

…

H 3.5 Was Main Feedwater not available or not recoverable using approved plant procedures during the scram response?

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. The qualifier of “not recoverable using approved plant procedures” will allow a licensee to answer “NO” to this question if there is no physical equipment restraint to prevent the operations staff from starting the necessary equipment, aligning the required systems, or satisfying required logic circuitry using plant procedures approved for use that were in place prior to the scram occurring.

The operations staff must be able to start and operate the required equipment using normal alignments and approved emergency, normal and off-normal operating procedures. Manual operation of controllers/equipment, even if normally automatic, is allowed if addressed by procedure. Situations that require maintenance or repair activities or non-proceduralized operating alignments will not satisfy this question. Additionally, the restoration of Main Feedwater must be capable of being restored to provide feedwater to the reactor vessel in a reasonable period of time. Operations should be able to start a Main Feedwater pump and start feeding the reactor vessel with the Main Feedwater System within about 30 minutes from the time it was recognized that Main Feedwater was needed~~post scram~~. During startup conditions where Main Feedwater was not placed in service prior to the scram, this question would not be considered, and should be skipped.

H 3.6 Following initial transient, did stabilization of reactor pressure/level and drywell pressure meet the entry conditions for EOPs?

Since BWR designs have an emergency high pressure system that operates automatically between a vessel-high and vessel-low level, it is not necessary for the Main Feedwater System to continue operating following a reactor trip. However, failure of the Main Feedwater System to be available is considered to be risk significant enough to require a "Yes" response for this PI. To be considered available, the system must be free from damage or failure that would prohibit restart of the system. Therefore, there is some reliance on the material condition or availability of the equipment to reach the decision for this question. Condenser vacuum, cooling water, and steam pressure values should be evaluated based on the requirements to operate the pumps~~,~~ and may be lower than normal if procedures allow pump operation at that lower value.

The estimated 30 minute time frame for restart of Main Feedwater was chosen based on restarting from a hot condition with adequate reactor water level. Since this time frame will not be measured directly, it should be an estimation developed based on the material condition of the plants systems following the reactor trip. If no abnormal material conditions exist, the 30 minutes should be capable of being met. If plant procedures and design would require more than 30 minutes, even if all systems were hot and the material condition of the systems following the reactor trip were normal, a routine time should be used in the evaluation of this question. The ~~considered opinion~~ judgment of an on-shift licensed SRO should be used in determining if ~~in meeting~~ this time frame is met~~acceptable~~.

When a scram occurs plant operators will enter the EOPs to respond to the condition. In the case of a routine scram the procedure entered will be exited fairly rapidly after verifying that the reactor is shutdown, excessive cooling is not in progress, electric power is available, and reactor coolant pressures and temperatures are at expected values and controlled. Once these verifications are done and the plant conditions considered "stable" (see guidance in the Definition of Terms section under ~~s~~*scram response*) operators will exit the initial procedure to another procedure that will stabilize and prepare the remainder of the plant for transition for the use of normal operating procedures. The plant would then be ready be maintained in Hot Standby, to perform a controlled normal cool down, or to begin the restart process. The criteria in this question is used to verify that there were no other conditions that developed during the stabilization of the plant in the scram response related vessel parameters that required continued operation in the EOPs or re-entry into the EOPs or transition to a follow-on EOP. Maintaining operation in EOPs that are not related to vessel and drywell parameters do not count in this PI.

For example:
Suppression Pool level high or low require entry into an EOP on Containment Control. Meeting EOP entry conditions for this EOP do not count in this PI.

Proposed FAQ 10-06

Plant: **Callaway Plant**
Date of Event: **2/6/10**
Submittal Date: **Proposed as 10/20/10**
Licensee Contact: **John Dowling, 314-225-1546, jdowling@ameren.com**
NRC Contact: **Jeremy Groom**
Performance Indicator: **Mitigating Systems**
Site Specific FAQ: **No**
FAQ requested to become effective when approved.

Question Section:

The Licensee and Resident Inspectors request clarification in the guidance for what constitutes cascaded unavailability. NEI 99-02 section 2.2, Mitigating System Performance Index, pages 31-36, provide the guidance on how to properly administer and report this performance indicator. On page 34, under the Monitored Systems section, line 37 states explicitly “No support systems are to be cascaded onto the monitored systems, e.g., HVAC room coolers, DC power, Instrument Air, etc.”

Appendix F section 2.1.3 provides guidance on how to define the boundaries of frontline system monitored components and support system components for the Unreliability element of MSPI. While this guidance could reasonably be extended to the unavailability section, there are no explicit statements regarding the definition of boundaries between frontline systems and support systems in the Unavailability element of MSPI.

What guidance should be used to define the frontline system and support system boundaries for the unavailability element of MSPI to ensure the “no cascading of unavailability” clause is met and unavailability is accurately reported?

Guidance needing clarification/interpretation:

Add a statement in Appendix F, section 1.2.1 regarding the establishment of boundaries between frontline and support system components for reporting unavailability consistent with the “No cascading of unavailability” clause from page 34.

Page F-6 "No Cascading of Unavailability" section should be clarified. Currently, all examples in this section refer to disabling a function of a monitored piece of equipment for protection when a support system is out of service. This could lead to an interpretation that these examples are the only conditions applicable to the “no cascading clause” on page 34.

Page F-29 "Failures and Discovered Conditions of Non-Monitored Structures, Systems, and Components" section does not appear to be consistent with the guidance of page 34 for no cascading of support systems onto monitored systems, specifically lines 20 – 23 … " An example could be a manual suction isolation valve left closed which would have caused a pump to fail. This would not be counted as a failure of the pump. Any mis-positioning of the valve that caused the train to be unavailable would be counted as unavailability from the time of discovery." This example does not indicate whether the mis-positioned valve was inside or outside the monitored system boundary, which introduces confusion. This example should include a statement that the mis-positioned valve is inside the monitored system boundary.

Event requiring guidance interpretation:

On February 6, 2010 a DC power supply failed in cabinet SA036C, the ESFAS Channel 2 termination/logic cabinet. This power supply failure resulted in declaring the Turbine Driven Auxiliary Feedwater Pump inoperable in accordance with Tech Spec requirements. No actions were taken that removed the capability of the pump to flow water to the steam generators. Licensee did not count unplanned unavailability for the Turbine Driven Auxiliary Feedwater train because it was considered “cascaded” unavailability from the ESFAS system. This cabinet is not within the train boundary for the Turbine Driven Auxiliary Feedwater train as identified in the Callaway MSPI Basis Document. Referring to Figure F-4 on page F-58 of Appendix F of NEI 99-02, the ESFAS system is outside the Turbine Driven Pump boundary. The failed power supply does not meet the definition of a support component as defined in INPO 98-001 "Supporting components – A supporting component exists in the plant solely to support the operation of a single key component. If a component supports multiple key components, it should be considered a key component." The failed power supply, SA036C, supports actuation signals to the two steam admission valves to the Turbine Driven Auxiliary Feedwater Pump, the Turbine Driven Auxiliary Feedwater Pump (a monitored component) the Turbine Driven Pump loss of suction pressure signal (one of 3 logic) to other Auxiliary Feedwater pumps suction valves, and the Automatic Test Insertion function. The two steam admission valves are within the MSPI boundary for the TDAFP train (TRAIN T) but are outside the boundary for the Turbine Driven Auxiliary Feedwater Pump and are not monitored components. Since SA036C supports more than one component, with only one of those being a monitored component, it can not be considered a supporting control component, and thus is not included within the boundary of the Turbine Driven Auxiliary Feedwater pump per the guidance of F.2.1.3.

Licensee's interpretation of cascaded unavailability is: monitored train unavailability resulting from equipment failure or other unavailability of a support system outside the boundary of the monitored train. NEI 99-02 Revision 6 page 34 lines 37 and 38 states: No support systems are to be cascaded onto monitored systems, e.g., HVAC room coolers, DC power, instrument air, etc. Licensee interprets the referenced NEI 99-02 Appendix F pages and sections above as clarification and reinforcement of the no cascading clause on page 34. However, these references can lend themselves to varied interpretation.

It is the Licensee’s position that the “Failures and Discovered Conditions of Non-Monitored Structures, Systems, and Components" section on page F-29, refers only to those components within the frontline system boundary and not to those components outside the boundary or to support system components. Any other interpretation would conflict with the general guidance against cascaded unavailability on page 34.

NRC Resident Inspector Position:

In the case of the failure of ESFAS Power Supply SA036C, the automatic start functions of the turbine driven auxiliary feedwater pump would be unavailable. Following the failure, the licensee did declare the turbine driven auxiliary feedwater pump inoperable. The resident inspectors believe the time associated with the failure of this power supply should count as unplanned unavailability for the turbine driven train of the auxiliary feedwater system. Unavailability is defined in NEI 99-02, Revision 6, Page 31, beginning on line 15.

> *Unavailability is the ratio of the hours the train/system was unavailable to perform its monitored functions (as defined by PRA success criteria and mission times) due to planned and unplanned maintenance or test during the previous 12 quarters while critical to the number of critical hours during the previous 12 quarters.*

NEI 99-02 (Page 31, Line 22-27) goes on to state that:

> *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.*

While the ESFAS Power Supply SA036C is a unmonitored component in MSPI (in terms of the Unreliability Index) the inspectors believe the time associated with the power supply failure should be included in the Unavailability Index based on the guidance in NEI 99-02, Revision 6, Page F-29, (Beginning on Line 18.)

> *"Failures of SSCs that are **<u>not included in the performance index</u>** will not be counted as a failure or a demand. Failures of SSCs that would have caused an SSC within the scope of the performance index to fail will not be counted as a failure or demand. An example could be a manual suction isolation valve left closed which would have caused a pump to fail. This would not be counted as a failure of the pump. Any mis-positioning of the valve **<u>that caused the train to be unavailable would be counted as unavailability from the time of discovery."</u>***

The inspectors believe this guidance indicates that failures of SSCs that are not included in the performance index will not be counted as a failure or a demand in the Unreliability Index but should be counted as unavailability from the time of discovery.

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

NA, there is agreement on facts and circumstances, but not on interpretation of the existing guidance as stated above.

Potentially relevant existing FAQ numbers: NA

Response Section:

Proposed Resolution of FAQ:
Provide a judgment as to the correct interpretation of NEI 99-02 guidance as it pertains to the question and event requiring guidance interpretation.

The licensee recommends incorporating the following proposed wording changes or changes with equivalent meaning into the next revision of NEI 99-02. The basis for this recommendation is to ensure consistency between NEI 99-02 section 2.2, Mitigating System Performance Index, pages 31-36, and NEI 99-02 and Appendix F Section's 1.2.1, 2.2.1 and 2.2.2 and provide explicit guidance as to the definition of boundaries between frontline systems and support systems in the Unavailability section.

Licensee proposed wording changes:

Bolded and underlined phrases indicate proposed changes, strike-throughs indicate deletions.

Page F-6

No Cascading of Unavailability: **There is no cascading of unavailability from support system components to frontline system monitored components. A failure of a support system component may require a monitored component to be declared Inoperable. If the monitored component is not rendered non-functional through tag out or physical plant conditions then no unavailable time should be accrued for the monitored component.**
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~~ **monitored train** in "maintenance" mode or by pulling the control fuses of the ~~supported~~ **monitored** component~~.~~ If no maintenance is being performed ~~on a supported component~~ **within a monitored train** and it is only ~~disabled for equipment protection~~ **unavailable** due to a support system being out of service, no unavailability should be reported for the train/segment. If however, maintenance is performed on the monitored ~~component~~ train, 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~~ **unavailable**, 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.

Page F-29

Failures and Discovered Conditions of Non-Monitored Structures, Systems, and Components (SSC)

This statement refers to Non-Monitored SSCs within the boundary of the frontline system.

Failures of SSCs that are not included in the performance index will not be counted as a failure or a demand. Failures of SSCs that would have caused an SSC within the scope of the performance index to fail will not be counted as a failure or demand. An example could be a manual suction isolation valve left closed which would have caused a pump to fail. This would not be counted as a failure of the pump. Any mis-positioning of the valve that caused the train to be unavailable would be counted as unavailability from the time of discovery. The significance of the mis-positioned valve prior to discovery would be addressed through the inspection process. (Note, however, in the above example, if the shut manual suction isolation valve resulted in an actual pump failure, the pump failure would be counted as a demand and failure of the pump.)

MITIGATING SYSTEM PERFORMANCE INDEX

Purpose

…

Indicator Definition

…

Unavailability is the ratio of the hours the train/system was unavailable to perform its monitored functions (as defined by the train/system boundaries, PRA success criteria and mission times) due to planned and unplanned maintenance or test during the previous 12 quarters while critical to the number of critical hours during the previous 12 quarters. (Fault exposure hours are not included; unavailable hours are counted only from the time of discovery of a failed condition to the time the train's monitored functions are recovered.) 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.

31

Data Reporting Elements

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Calculation

…

Plant Specific PRA

…

Definition of Terms

***Risk Significant Functions**:* those at power functions, described in the Appendix F section "Additional Guidance for Specific Systems," that were determined to be risk-significant in accordance with NUMARC 93-01, or NRC approved equivalents (e.g., the STP exemption request). The risk significant system functions described in Appendix F, "Additional Guidance for Specific Systems" should be modeled in the plant's PRA/PSA. System and equipment performance requirements for performing the risk significant functions are determined from the PRA success criteria, mission times, and boundaries for the system.

33

 Received 2/14/11

<u>Clarifying Notes</u>

Documentation and Changes

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Changes to PRA coefficient:

…

Changes to non-PRA information:

…

Monitored Systems

Systems have been generically selected for this indicator based on their importance in preventing reactor core damage. The systems include the principal systems needed for maintaining reactor coolant inventory following a loss of coolant accident, for decay heat removal following a reactor trip or loss of main feedwater, and for providing emergency AC power following a loss of plant off-site power. One support function (cooling water support system) is also monitored. The cooling water support system monitors the cooling functions provided by service water and component cooling water, or their direct cooling water equivalents, for the four front-line monitored systems. <u>Other</u>~~No~~ support systems <u>(e.g., HVAC room coolers, DC power, instrument air, etc.)</u> ~~are to~~<u>will not</u> be cascaded onto the monitored systems<u>'</u>~~, e.g., HVAC room coolers, DC power, instrument air, etc.~~ <u>unavailability or reliability data. For the purposes of MSPI, a failure of a support system component that is outside the system and train boundary of a monitored system will not result in unavailability of a monitored train or failure of a monitored component.</u>

Diverse Systems

…

Use of Plant-Specific PRA and SPAR Models

…

<u>APPENDIX F</u>

**METHODOLOGIES FOR COMPUTING THE UNAVAILABILITY INDEX,
THE UNRELIABILITY INDEX AND COMPONENT PERFORMANCE LIMITS**

 Received 2/14/11

This appendix provides the details of three calculations: the System Unavailability Index, the System Unreliability Index, and component performance limits.

F 1. System Unavailability Index (UAI) Due to Train Unavailability

…

F 1.1. Identification of System Trains

…

F 1.1.1. Monitored Functions and System Boundaries

The first step in the identification of system trains is to define the monitored functions and system boundaries. Include all components within the system boundary that are required to satisfy the monitored functions of the system. Support systems (e.g., HVAC room coolers, DC power, instrument air, etc.) may be needed to satisfy a monitored function; however, if the failure of a support system component is outside of the system and train boundary of the monitored system, no unavailability or failure should be cascaded onto the monitored train or component respectively.

F-1

…

System Interface Boundaries

…

Water Sources and Inventory

Water tanks are not considered to be monitored components. As such, they do not contribute to URI. However, since tanks can be in the train boundary, periods of insufficient water inventory contribute to UAI if they result in loss of the monitored train function for the required mission time. If additional water sources are required to satisfy train mission times, only the connecting active valve from the additional water source is considered as a monitored component for calculating UAI. If there are valves in the primary water source that must change state to permit use of the additional water source, these valves are considered monitored and should be included in UAI for the system.

F-2

Unit Cross-Tie Capability

…

Common Components

…

F 1.1.2. IDENTIFICATION OF TRAINS WITHIN THE SYSTEM

…

Cooling Water Support Systems and Trains

…

Unit Swing trains and components shared between units

…

Maintenance Trains and Installed Spares

…

Trains or Segments that Cannot Be Removed from Service

…

F 1.2. COLLECTION OF PLANT DATA

…

F 1.2.1. Actual Train Unavailability

…

Unplanned unavailable hours: These hours include elapsed time between the discovery and the restoration to service of an equipment failure or human error (such as a misalignment) that makes the train unavailable. 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. Unavailable hours to correct discovered conditions that render a monitored ~~component~~ train incapable of performing its monitored function are counted as unplanned unavailable hours. An example of this is a condition discovered by an operator on rounds, such as an obvious oil leak, that was determined to have resulted in the equipment being non-functional even though

no demand or failure actually occurred. Unavailability due to mis-positioning of components that renders a train incapable of performing its monitored function~~s~~ is included in unplanned unavailability for the time required to recover the monitored function.

No Cascading of Unavailability Between Two Monitored Systems: In some cases plants will disable the autostart of a supported monitored system when the support monitored 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~~monitored train in "maintenance" mode or by pulling the control fuses of the ~~supported~~ monitored component. If no maintenance is being performed ~~on a supported component~~within a monitored train and it is only ~~disabled for equipment protection~~unavailable due to another monitored system ~~support system~~ being out of service (i.e., service or cooling water), no unavailability should be reported for the train/segment. If, however, maintenance is performed on the monitored ~~component~~train such that the train is rendered unavailable, 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~~unavailable, 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.

Additional guidance on the following topics for counting train unavailable hours is provided below.

- Short Duration Unavailability
- Credit for Operator Recovery Actions to Restore the Monitored Function

Short Duration Unavailability

…

Credit for Operator Recovery Actions to Restore the Monitored Functions

…

Counting Unavailability when Planned and Unplanned Maintenance are Performed in the Same Work Window

...

Failures and Discovered Conditions of Non-Monitored Structures, Systems, and Components (SSC)

Failures of SSCs that are not included as monitored components in the performance index will not be counted as a failure or a demand. Failures of non-monitored SSCs that would have caused a monitored component~~n SSC~~ within the scope of the performance index to fail will not be counted as a failure or demand of the monitored component. An example could be a manual suction isolation valve left closed which would have caused a pump to fail. In this case, the

 Received 2/14/11

manual suction valve is with in the train boundary but is not a monitored component. The~~is~~ closed manual isolation valve would not be counted as a failure of the pump; however, a~~. A~~ny mis-positioning of the valve that caused the train to be unavailable would be counted as unavailability from the time of discovery. The significance of the mis-positioned valve prior to discovery would be addressed through the inspection process. (Note, however, in the above example, if the shut manual suction isolation valve resulted in an actual pump failure, the pump failure would be counted as a demand and failure of the pump.)

F-29

PWR Auxiliary Feedwater Systems

Scope

The function of the AFW system is to provide decay heat removal via the steam generators to cool down and depressurize the reactor coolant system following a reactor trip. The mitigation of ATWS events with the AFW system is not considered a function to be monitored by the MSPI. (Note, however, that the FV values will include ATWS events).

The function monitored for the indicator is the ability of the AFW system to take a suction from a water source (typically, the condensate storage tank and if required to meet the PRA success criteria and mission time, from an alternate source), and to inject into at least one steam generator~~.~~[s1] after receiving an auto actuation signal.

The scope of the auxiliary feedwater (AFW) or emergency feedwater (EFW) systems includes the pumps and the components in the flow paths from the condensate storage tank [s2]and, if required, the valve(s) that connect the alternative water source to the auxiliary feedwater system. The flow path for the steam supply to a turbine driven pump is included from the steam source (main steam lines) to the pump turbine. Pumps included in the Technical Specifications (subject to a Limiting Condition for Operation) are included in the scope of this indicator. Some initiating events, such as a feedwater line break, may require isolation of AFW flow to the affected steam generator to prevent flow diversion from the unaffected steam generator. This function should be considered a monitored function if it is required.

F-50

Train Determination

…

 Received 2/14/11

Plant: Generic
Date of Event: N/A
Submittal Date: 12/1/2010
Licensee Contact: Jim Slider Tel/email: 202.739.8015/jes@nei.org
NRC Contact: Steve Vaughn Tel/email: 301.415.3640/Stephen.Vaughn@nrc.gov

Performance Indicator: USwC – IE04

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 21, lines 5-13; Page 23, line 15-23; H-5, line 39-46; H-6, lines 1-12; H-20, lines 21-46; H-21, line 1-11;

Event or circumstances requiring guidance interpretation:

As stated in FAQ 10-05 (ID #475), Palo Verde proposed additional wording to Appendix D of NEI 99-02 that would relieve Combustion Engineering (CE) plants from reporting a complicated scram for loss of forced cooling (LOFC) events as long as the LOFC event was not caused by a loss of off-site power (LOOP). The guidance in NEI 99-02 was clear and did not result in a question of interpretation; rather, the licensee sought relief from the reporting guidance. The NRC determined that the LOFC at Palo Verde counted as a complicated scram because more than one EOP was entered while the operators responded to the event. However, representatives from Palo Verde expressed concern that Westinghouse plants were at an unfair advantage because the structure of their EOPs would lead to a different determination under the PI guidance for the same scram. For example, a scram at a Westinghouse plant might result in only one EOP entry, while the same scram at a CE plant might result in entering multiple EOPs. The ROP Working Group agreed to initiate a generic FAQ to evaluate the potential disparity among vendor designs and recommend changes to "level the playing field."

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

Potentially relevant existing FAQ numbers
FAQ 10-05 (ID #475)

Response Section
Proposed Resolution of FAQ: Revise the guidance to ensure that a similar scram experienced at different vendor sites will result in consistent implementation.
Proposed Changes to NEI 99-02

Page 21, lines 5-13:

The response to the scram must be completed without transitioning to an additional EOP after entering the scram response procedure (e.g., ES01 for Westinghouse). This step is used to determine if the scram was uncomplicated by counting if additional procedures beyond the normal scram response required entry after the scram. A plant exiting the normal scram response procedure without using another EOP would answer this step as "No". Approved exceptions to this requirement include: 1) the discretionary use of the lowest level Function Restoration Guideline (Yellow Path) by the operations staff, 2) use of the Re-diagnosis Procedure by Operations unless a transition to another EOP is required, and 3) **entry into another EOP** when securing forced circulation if maintenance of natural circulation is addressed in the separate EOP.

Page H-6, lines 5-12:

There are some EOPs that are used specifically at the operator discretion and are not required to be used. In the Westinghouse EOP suite these are Yellow Path functional restoration procedures and the re-diagnosis procedures. These procedures typically verify that the operator is taking the correct action (re-diagnosis) or the stabilization of some minor plant parameters (Yellow path). Use of these procedures is an allowed exception to this step.

In addition, the scope of the Westinghouse normal scram response procedure (ES01) encompasses loss of forced circulation events, whereas other PWR EOP schemes may require entry into a separate EOP. Loss of forced circulation events, in themselves, do not result in complications for the operator nor are they risk-significant unless required in response to an event such as Loss of Offsite Power. Therefore, in order to treat events of similar type consistently, entry into an additional EOP specific to a loss of forced circulation event is likewise an allowed exception to this step. Maintenance of the plant in Mode 3 on natural circulation requires monitoring of temperatures that are already monitored. This does not involve additional challenges to plant safety functions or the control staff. If the EOP scheme has the control room operator exit the normal scram procedure for a Loss of Forced Circulation and the EOP was exited upon restoration of forced circulation without commencing a plant cool down, then the use of an additional EOP to address the Loss of Forced Circulation shall not require counting under this criterion. If the EOP was used in response to an event such as a Loss of Off-site Power, this exception cannot be used.

Other than the above described exceptions, transition out of these procedures to an EOP different from the current procedure in effect, i.e. a new procedure or the base procedure, would count as a complication.

FAQ 11-01: Cooling Water Boundary (Generic)

Updated 3/7/2011

Plant: Generic
Date of Event: NA
Submittal Date: 01/20/11
Licensee Contact: Jim Peschel, Tel/email: 603.773.7194/james_peschel@nexteraenergy.com
NRC Contact: Steve Vaughn, Tel/email: 301.415.3640/stephen.vaughn@nrc.gov

Performance Indicator: MS-10, Mitigating System Performance Index (Cooling Water Systems)

Site Specific FAQ (Appendix D)? No

FAQ requested to become effective: October 1, 2011

Question Section

NEI 99-02, Rev. 6, provides guidance for the cooling water system scope on pages F-52 and F-53. The text from page F-53, lines 2 through 7, highlighted in italics below, indicates that only the last valve in a cooling water system line is included in the boundary of the monitored component. While this may be correct in most applications, there are plant configurations where a cooling water system line running to a monitored system (EDG for example) has more than one isolation valve (e.g., manual isolation valve(s)). If the isolation valve(s) were closed it would only result in supported train unavailability and would not affect the availability of the cooling water system. However, the guidance on page F-53, lines 2 through 7, could lead one to the opposite conclusion and suggest that the cooling water system would be unavailable.

NEI 99-02, Rev. 6, Page F-53, lines 1 through 9:

> Systems that provide this function typically include service water and component cooling water or their cooling water equivalents. *Pumps, valves, heat exchangers and line segments that are necessary to provide cooling to the other monitored systems are included in the system scope up to, but not including, the last valve that connects the cooling water support system to components in a single monitored system. This last valve is included in the other monitored system boundary. If the last valve provides cooling to SSCs in more than one monitored system, then it is included in the cooling water support system.* Service water systems are typically open "raw water" systems that use natural sources of water such as rivers, lakes or oceans. Component Cooling Water systems are typically closed "clean water" systems.

<u>Question</u> - Should a cooling water system isolation valve(s) in a line supplying a single monitored component be included in the monitored train's system boundary?

The industry and the NRC agree on the issue and question as described above.

Response Section

<u>Response</u> – Yes, a cooling water system isolation valve(s) in a line supplying a single monitored train should be included in the monitored train's system boundary.

Revise NEI 99-02, Rev. 6, Page F-53, lines 1 through 9, to read as follows:

> Systems that provide this function typically include service water and component cooling water or their cooling water equivalents. Pumps, valves, heat exchangers and line segments that are

necessary to provide cooling to the other monitored trains or segments are included in the cooling water system scope up to, but not including, the ~~last~~ isolation valve(s) that connect(s) the cooling water support system to components in a single monitored ~~system~~ train or segment. This ~~last~~ isolation valve is included in the monitored train or segment boundary. The last valve(s) that provides cooling to SSCs in more than one monitored train or segment is included in the cooling water support system. All valves (e.g., manual isolation valves or motor operated valves (MOVs)) in a cooling water line to single monitored train or segment are included in the monitored train or segment boundary. Figure F-6 depicts the treatment of multiple isolation valves. Service water systems are typically open "raw water" systems that use natural sources of water such as rivers, lakes or oceans. Component Cooling Water systems are typically closed "clean water" systems.

###

Cooling Water System Boundary

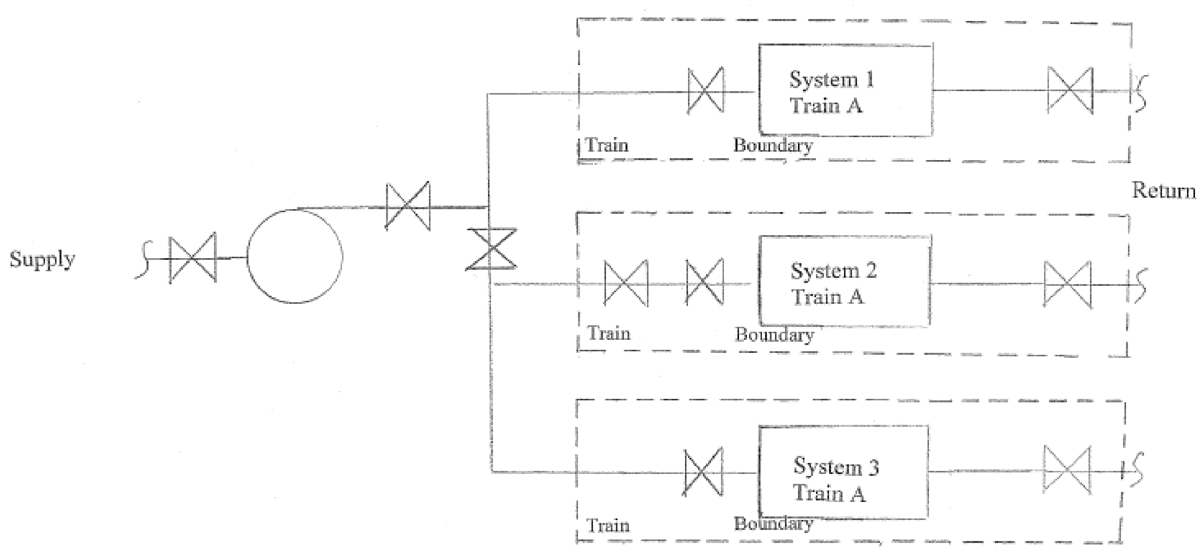


Figure F-6

FAQ TEMPLATE
FAQ 11-01: Cooling Water Boundary (Generic)
Updated 3/7/2011

Plant: Generic
Date of Event: NA
Submittal Date: 01/20/11
Licensee Contact: Jim Peschel, Tel/email: 603.773.7194/james_peschel@nexteraenergy.com
NRC Contact: Steve Vaughn, Tel/email: 301.415.3640/stephen.vaughn@nrc.gov

Performance Indicator: MS-10, Mitigating System Performance Index (Cooling Water Systems)

Site Specific FAQ (Appendix D)? No

FAQ requested to become effective: October 1, 2011

Question Section

NEI 99-02, Rev. 6, provides guidance for the cooling water system scope on pages F-52 and F-53. The text from page F-53, lines 2 through 7, highlighted in italics below, indicates that only the last valve in a cooling water system line is included in the boundary of the monitored component. While this may be correct in most applications, there are plant configurations where a cooling water system line running to a monitored system (EDG for example) has more than one isolation valve (e.g., manual isolation valve(s)). If the isolation valve(s) were closed it would only result in supported train unavailability and would not affect the availability of the cooling water system. However, the guidance on page F-53, lines 2 through 7, could lead one to the opposite conclusion and suggest that the cooling water system would be unavailable.

NEI 99-02, Rev. 6, Page F-53, lines 1 through 9:

> Systems that provide this function typically include service water and component cooling water or their cooling water equivalents. *Pumps, valves, heat exchangers and line segments that are necessary to provide cooling to the other monitored systems are included in the system scope up to, but not including, the last valve that connects the cooling water support system to components in a single monitored system. This last valve is included in the other monitored system boundary. If the last valve provides cooling to SSCs in more than one monitored system, then it is included in the cooling water support system.* Service water systems are typically open "raw water" systems that use natural sources of water such as rivers, lakes or oceans. Component Cooling Water systems are typically closed "clean water" systems.

Question - Should a cooling water system isolation valve(s) in a line supplying a single monitored component be included in the monitored train's system boundary?

The industry and the NRC agree on the issue and question as described above.

Response Section

Response – Yes, a cooling water system isolation valve(s) in a line supplying a single monitored train should be included in the monitored train's system boundary.

Revise NEI 99-02, Rev. 6, Page F-53, lines 1 through 9, to read as follows:

> Systems that provide this function typically include service water and component cooling water or their cooling water equivalents. Pumps, valves, heat exchangers and line segments that are

necessary to provide cooling to the other monitored ~~systems~~ trains or segments are included in the cooling water system scope up to, but not including, the ~~last~~ isolation valve(s) that connect(s) the cooling water support system to components in a single monitored ~~system~~ train or segment. This/these ~~last~~ isolation valve is/are included in the ~~other~~ monitored ~~system~~ train or segment boundary. ~~If the~~The last valve(s) that provides cooling to SSCs in more than one monitored ~~system or train~~train or segment~~, then it~~ is included in the cooling water support system. ~~If the cooling water line to a single monitored component or train contains components~~All valves (e.g., manual isolation valves or motor operated valves (MOVs))~~ that would only affect the monitored component or train, those components~~ in a cooling water line to single monitored train or segment are included in the ~~other system~~monitored train or segment boundary. Figure F-~~1~~ 6 depicts the treatment of multiple isolation valves. Service water systems are typically open "raw water" systems that use natural sources of water such as rivers, lakes or oceans. Component Cooling Water systems are typically closed "clean water" systems.

###

Cooling Water System Boundary

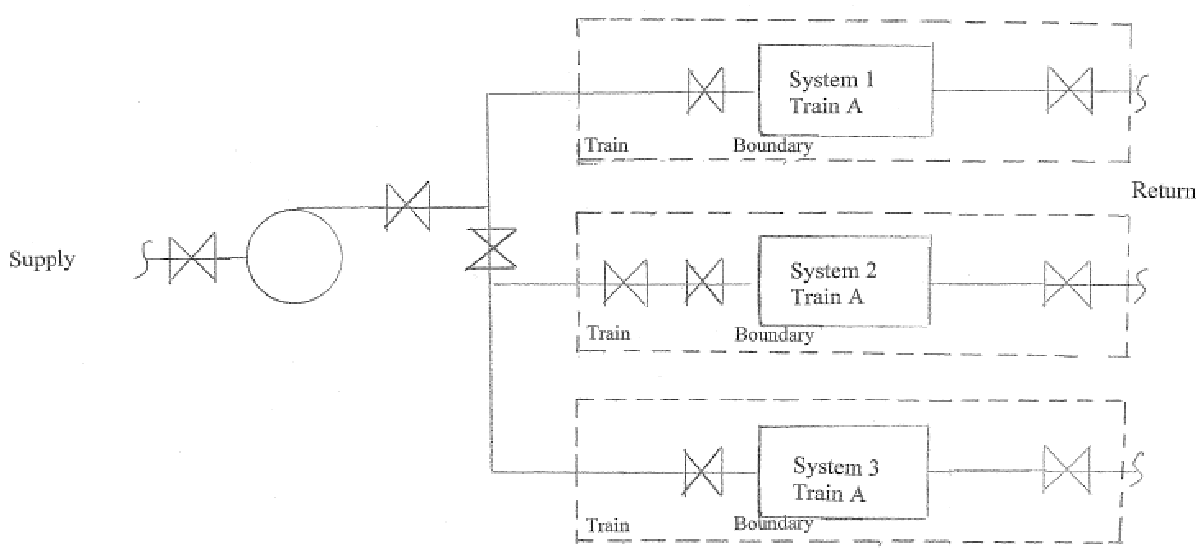


Figure F-6

FAQ TEMPLATE

FAQ 11-04 Updated 3/21/2011

Power Changes Needed to Recover from Loss of Equipment

Plant: Generic
Date of Event: June 4, 2010
Submittal Date: January 20, 2011
Contact: Robin Ritzman **Tel/email:** 330-384-5414 rritzman@firstenergycorp.com
NRC Contact: Jocelyn Lian **Tel/email:** 301-415-4666 Jocelyn.Lian@nrc.gov

Performance Indicator: IE03 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):
Page 13, Lines 24 – 29

Event or circumstances requiring guidance interpretation:

At 0707 hours on June 4, 2010, the Perry Plant entered single loop operation (SLO) when reactor recirculation pump A tripped OFF due to a failed optical isolator card. Reactor power in SLO was approximately 58% RTP. This power change is counted as an unplanned power change under the PI because the power change was greater than 20% (100% to 58%) and was initiated less than 72 hours following discovery of the off-normal condition.

After replacing the optical isolator card, it was necessary to reduce power to approximately 21% to establish reactor conditions necessary to restart reactor recirculation pump A and commence power ascension. The power reduction began at 2220 hours and ended at 1827 hours on June 5, 2010. The second power reduction was also counted as an unplanned power change under the PI because the power change was greater than 20% (58% to 21%) and was initiated less than 72 hours following discovery of the off-normal condition.

The question being asked in this case is whether the second power reduction should be counted as a separate occurrence. Clearly, the second power reduction was implemented to address the initial condition (i.e., reactor recirculation pump A trip). It is not desirable for a boiling water reactor (BWR) to operate in SLO for long periods of time, although SLO is a licensed operating mode. The reactor has to be brought a condition with adequate margins to thermal limits and stability in order to re-start the non-operating recirculation pump after repairs are completed. A power reduction is necessary to reach those conditions. The operating recirculation pump has to be transferred to slow speed. Then, the non-operating pump is started in slow speed at the desired power level. Power ascension may commence with both pumps running in slow speed.

The indicator monitors the number of unplanned power changes that could have, under other plant conditions, challenged safety functions. Operating in SLO in accordance with Technical Specifications does not challenge nuclear safety or is in itself, risk-significant. Therefore, a second power reduction to recover a non-operating recirculation pump does not appear to be within the intent of the PI.

The guidance on NEI 99-02 page 14 lines 23 through 30 and beginning on line 42 indicates that power changes resulting from proper implementation of preexisting procedural guidance which are not in response to an equipment failure or personnel error are not meant to be counted by this indicator. This is in direct contrast to power changes resulting from equipment failures or personnel errors. Consistent this guidance, voluntary power changes (i.e., the timing of the power change was at the discretion of plant management and not a result of degrading conditions) to restore equipment to service in accordance with previously existing procedures does not contribute to this indicator either by adding to the magnitude of the initiating event unplanned power change or being counted separately.

Guidance in NEI 99-02 is requested to clarify reporting criteria for situations similar to ~~this~~ the Perry event, where a power reduction is required to place equipment in service, such as to recover a non-operating reactor recirculation pump. No clarification is needed for the initial trip to enter SLO which will be counted and reported under the PI.

If licensee and NRC resident/region do not agree on the facts and circumstances, explain
The NRC resident inspector agrees with the facts as stated in the FAQ. In the Perry case that initiated this FAQ, both unplanned power changes were reported. The NRC inspector believes that NEI 99-02, as written, requires two unplanned power changes to be reported.

Potentially relevant existing FAQ numbers
None identified.

Response Section

Proposed Resolution of FAQ
~~A p~~Power ~~reduction greater than 20% RTP~~changes implemented less than 72 hours from time of discovery, in accordance with ~~an approved~~preexisting procedures, for the purpose of placing equipment in service, such as restarting a non-operating reactor recirculation pump in a BWR plant or a heater drain pump, should not be reported under this PI~~ because it is considered to be part of the same event~~. The initiating event or condition that resulted in the need to restore the equipment is the event evaluated under this criterion.

If appropriate, provide proposed rewording of guidance for inclusion in next revision.
Add to Clarifying Notes for Unplanned Power Changes per 7,000 Critical Hours in NEI 99-02, page~~s 13-16~~ 14: ~~"In some cases, power changes are necessary to place equipment in service. For example, in BWRs, a proceduralized power reduction greater than 20% for the purpose of re-starting a reactor recirculation pump to re-establish two-loop operation is excluded following an initial power reduction of greater than 20% caused by a recirculation pump trip. This event is not counted twice because the second power reduction to recover the tripped recirculation pump is implemented by an approved procedure~~ ~~and is considered to be part of the same event.~~

~~A second power reduction to recover equipment within a 72-hour timeframe should be considered to be the same event as the original power reduction. However, if the causes of the multiple power reductions within a 72-hour period are different, they should be treated as separate events."~~

Current Guidance:
16 Unplanned power changes and shutdowns include those conducted in response to equipment
17 failures or personnel errors and those conducted to perform maintenance. They do not include
18 automatic or manual scrams or load-follow power changes.

Add the following to the end of the sentence on line 17:

Voluntary power changes (i.e., the timing of the power change was at the discretion of plant management and not a result of degrading conditions) to restore equipment to service in accordance with previously existing procedures does not contribute to this indicator either by adding to the magnitude of an initiating event unplanned power change or being counted separately.

Current Guidance:
23 Unplanned power changes include runbacks and power oscillations greater than 20% of full
24 power. A power oscillation that results in an unplanned power decrease of greater than 20%
25 followed by an unplanned power increase of 20% should be counted as two separate PI events,
26 unless the power restoration is implemented using approved procedures. For example, an
27 operator mistakenly opens a breaker causing a recirculation flow decrease and a decrease in
28 power of greater than 20%. The operator, hearing an alarm, suspects it was caused by his action
29 and closes the breaker resulting in a power increase of greater than 20%. Both transients would
30 count since they were the result of two separate errors (or unplanned/non-proceduralized action).

Add the following to the end of line 30:
Alternately, if the power change is implemented to restore equipment to service and is performed using a previously existing approved procedure, the power change(s) (increases or decreases) to restore the equipment to service would not count against this indicator.

FAQ TEMPLATE

FAQ 11-04 Updated 3/21/2011

Power Changes Needed to Recover from Loss of Equipment

Plant: Generic
Date of Event: June 4, 2010
Submittal Date: January 20, 2011
Contact: Robin Ritzman **Tel/email:** 330-384-5414 rritzman@firstenergycorp.com
NRC Contact: Jocelyn Lian **Tel/email:** 301-415-4666 Jocelyn.Lian@nrc.gov

Performance Indicator: IE03 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):
Page 13, Lines 24 – 29

Event or circumstances requiring guidance interpretation:

At 0707 hours on June 4, 2010, the Perry Plant entered single loop operation (SLO) when reactor recirculation pump A tripped OFF due to a failed optical isolator card. Reactor power in SLO was approximately 58% RTP. This power change is counted as an unplanned power change under the PI because the power change was greater than 20% (100% to 58%) and was initiated less than 72 hours following discovery of the off-normal condition.

After replacing the optical isolator card, it was necessary to reduce power to approximately 21% to establish reactor conditions necessary to restart reactor recirculation pump A and commence power ascension. The power reduction began at 2220 hours and ended at 1827 hours on June 5, 2010. The second power reduction was also counted as an unplanned power change under the PI because the power change was greater than 20% (58% to 21%) and was initiated less than 72 hours following discovery of the off-normal condition.

The question being asked in this case is whether the second power reduction should be counted as a separate occurrence. Clearly, the second power reduction was implemented to address the initial condition (i.e., reactor recirculation pump A trip). It is not desirable for a boiling water reactor (BWR) to operate in SLO for long periods of time, although SLO is a licensed operating mode. The reactor has to be brought a condition with adequate margins to thermal limits and stability in order to re-start the non-operating recirculation pump after repairs are completed. A power reduction is necessary to reach those conditions. The operating recirculation pump has to be transferred to slow speed. Then, the non-operating pump is started in slow speed at the desired power level. Power ascension may commence with both pumps running in slow speed.

The indicator monitors the number of unplanned power changes that could have, under other plant conditions, challenged safety functions. Operating in SLO in accordance with Technical Specifications does not challenge nuclear safety or is in itself, risk-significant. Therefore, a second power reduction to recover a non-operating recirculation pump does not appear to be within the intent of the PI.

The guidance on NEI 99-02 page 14 lines 23 through 30 and beginning on line 42 indicates that power changes resulting from proper implementation of preexisting procedural guidance which are not in response to an equipment failure or personnel error are not meant to be counted by this indicator. This is in direct contrast to power changes resulting from equipment failures or personnel errors. Consistent this guidance, voluntary power changes (i.e., the timing of the power change was at the discretion of plant management and not a result of degrading conditions) to restore equipment to service in accordance with previously existing procedures does not contribute to this indicator either by adding to the magnitude of the initiating event unplanned power change or being counted separately.

Guidance in NEI 99-02 is requested to clarify reporting criteria for situations similar to the Perry event, where a power reduction is required to place equipment in service, such as to recover a non-operating reactor recirculation pump. No clarification is needed for the initial trip to enter SLO which will be counted and reported under the PI.

If licensee and NRC resident/region do not agree on the facts and circumstances, explain
The NRC resident inspector agrees with the facts as stated in the FAQ. In the Perry case that initiated this FAQ, both unplanned power changes were reported. The NRC inspector believes that NEI 99-02, as written, requires two unplanned power changes to be reported.

Potentially relevant existing FAQ numbers
None identified.

Response Section

Proposed Resolution of FAQ
Power changes implemented less than 72 hours from time of discovery, in accordance with preexisting procedures, for the purpose of placing equipment in service, such as restarting a non-operating reactor recirculation pump in a BWR plant or a heater drain pump, should not be reported under this PI. The initiating event or condition that resulted in the need to restore the equipment is the event evaluated under this criterion.

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

Add to Clarifying Notes for Unplanned Power Changes per 7,000 Critical Hours in NEI 99-02, page 14:

Current Guidance:

Unplanned power changes and shutdowns include those conducted in response to equipment failures or personnel errors and those conducted to perform maintenance. They do not include automatic or manual scrams or load-follow power changes.

Add the following to the end of the sentence on line 17:

Voluntary power changes (i.e., the timing of the power change was at the discretion of plant management and not a result of degrading conditions) to restore equipment to service in accordance with previously existing procedures does not contribute to this indicator either by adding to the magnitude of an initiating event unplanned power change or being counted separately.

Current Guidance:

Unplanned power changes include 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).

Add the following to the end of line 30:

Alternately, if the power change is implemented to restore equipment to service and is performed using a previously existing approved procedure, the power change(s) (increases or decreases) to restore the equipment to service would not count against this indicator.

FAQ Template
FAQ 11-05: Point Beach Unit 1 and Unit 2 Auxiliary Feedwater (AF) Systems
Introduced 1/20/11

Plant:	Point Beach Units 1 and 2
Date of Event:	NA
Submittal Date:	January 20, 2011
Licensee Contact:	Carol Jilek, 920-755-7345, carol.jilek@nexteraenergy.com
NRC Contact:	NA
Performance Indicator:	MS-08, Heat Removal Systems
Site Specific FAQ (Appendix D)?	YES

FAQ requested to become effective upon Point Beach implementation of the new technical specification for the Auxiliary Feedwater (AF) Systems in the second quarter of 2011.

This purpose of this FAQ is to request an exemption from the guidance of NEI 99-02 due to plant-specific circumstances at Point Beach involving major design changes to the Unit 1 and Unit 2 AF systems that are scheduled to be implemented during the second quarter of 2011. Reference NEI 99-02, Appendix E, page E-1, lines 18 and 19.

Question Section

Issue: Point Beach is upgrading the Unit 1 and Unit 2 auxiliary feedwater systems (AF) during the second quarter of 2011 with Unit 2 being completed during the spring outage and Unit 1 while the plant is on line. The current AF design has two motor-driven AF pumps that are shared between the two units. In the current configuration, the operating unit has planned unavailability during the other unit's refueling outage. After the upgrade modifications are completed, the AF system will have one new motor-driven pump dedicated to each unit and will no longer have planned unavailability during the alternate unit's refueling outage. The new pumps will be the same model casing as the old pumps, but will have a different impeller, resulting in a higher flow rate, and will be powered by 4160V versus 480V. The preventive maintenance activities for the new pumps and associated monitored valves will be essentially the same as those for the existing pumps and associated monitored valves. The change will reduce the number of motor-driven AF trains from two to one per unit and will change the generic common cause failure adjustment value from 1.25 to 1.0 in NEI 99-02, Appendix F, Table 7.

The refueling outage is scheduled to be completed during the second quarter of 2011. As the units will be putting the new AF pumps and associated monitored valves in service during the middle of a quarter, the device records in CDE will be updated upon entry into MODE 4 ascending for Unit 2 and when the new AF pump and associated monitored valves are placed in service for Unit 1. However, CDE and the MSPI Basis Document will not be updated until the end of the second quarter to reflect the new PRA and the new train definitions.

The completion of the modification during the middle of a quarter will result in the inability to implement all of the guidance in NEI 99-02 related to reporting of data in CDE. The goal is to provide a second quarter MSPI submittal for AF that accurately reflects the actual availability and reliability of the existing and new AF system configurations and implements the guidance of NEI 99-02 as much as reasonable. However, as CDE does not support the submittal of split data and does not allow PRA model changes mid-quarter, an MSPI result for MS08, Heat Removal Systems, reflecting second quarter 2011 AF system unavailability and reliability would not be representative of the new system and would not provide meaningful results. Therefore, the following exemptions from NEI 99-02 guidance are requested for Point Beach based upon the system design changes being implemented in the second quarter of 2011.

Questions:

1. Is it acceptable to gray out MS08, Heat Removal Systems, for the second quarter of 2011 as the results will not be meaningful?

2. As the new pumps and associated monitored valves will be similar to the existing pumps and associated monitored valves, is it acceptable to determine the baseline data (nominally 2002-2004) for the new pumps and associated monitored valves by utilizing the data for the existing pumps and associated monitored valves, removing the unavailability taken when the other unit was in an outage and averaging the data?

3. As the new pumps and associated monitored valves will be similar to the existing pumps and associated monitored valves, is it acceptable to determine the past three years historical data for the new pumps and associated monitored valves by utilizing the data for the existing pumps and associated monitored valves, removing the unavailability taken when the other unit was in an outage and averaging the data?

4. Is it acceptable to update the device records in CDE at the time the new pumps and associated monitored valves are placed in service and to update the train definition in the MSPI Basis Document at the end of the second quarter of 2011?

5. Is it acceptable to revise the generic common cause failure adjustment value in NEI 99-02, Appendix F, Table 7 from 1.25 to 1.0 per this FAQ and to update NEI 99-02 at a later date after the systems are placed in service?

<u>Resolution</u>

1. Yes - It is appropriate to gray out MS08, Heat Removal Systems, for the second quarter of 2011 as the results will not be meaningful. A note shall be added to the CDE submittal file explaining why the indicator is gray.

2. Yes - As the new pumps and associated monitored valves will be similar to the existing pumps and associated monitored valves, it is acceptable to determine the baseline data (nominally 2002-2004) for the new pumps and associated monitored valves by utilizing the data for the existing pumps and associated monitored valves, removing the unavailability taken when the other unit was in an outage and averaging the data.

3. Yes - As the new pumps and associated monitored valves will be similar to the existing pumps and associated monitored valves, it is acceptable to determine the past three years historical data for the new pumps and associated monitored valves by utilizing the data for the existing pumps and associated monitored valves, removing the unavailability taken when the other unit was in an outage and averaging the data.

4. Yes - It is acceptable to update the device records in CDE at the time the new pumps and associated monitored valves are placed in service and to update the train definition in the MSPI Basis Document at the end of the second quarter.

5. Yes - It is acceptable to revise the generic common cause failure adjustment value in NEI 99-02, Appendix F, Table 7 from 1.25 to 1.0 per this FAQ and to update NEI 99-02 at a later date after the systems are placed in service.

Plant: **Generic**
Date of Event: **N/A**
Submittal Date: **2/16/11**
Licensee Contact: **Roy Linthicum, 630-657-3846, roy.linthicum@exeloncorp.com**
NRC Contact: **Steve Vaughn**
Performance Indicator: **Mitigating Systems**
Site Specific FAQ: **No**
FAQ requested to become effective: October 1, 2011

Question Section:

NEI 99-02 section F.2.2.1, Mitigating System Performance Index, page F-20, provides the guidance for counting EDG run hours. During initiate implementation of MSPI, it was decided to include the 1st hour of run time for the EDGs in the run hours calculations, even though failures within the 1st hour or operation are either EDG demand or Load/Run failures, as it was expected to result in a small impact to the calculated . A recent investigation (ML 101580244) concluded that in order to maintain the industry generic failure rates used as a comparison for MSPI, the 1st hour of operation for the EDGs must be **excluded** from the run hours calculations. Inclusion of the 1st hour or operation results in almost a factor of 1.5 reduction in the industry prior failure rate used for MSPI.

The impact of not counting the 1st hour of operation on historical MSPI reporting identified that excluding the 1st hour of operation from the EDG run hours would not have resulted in any change in indicator color. Therefore, this change will be made for future reporting only.

Guidance needing clarification/interpretation:

Revise NEI 99-02 section F.2.2.1 and F.2.2.2 eliminate the addition of the 1st hour of EDG operation from the run hour data that is input into the CDE database.

Event requiring guidance interpretation:

N/A. This FAQ is for general guidance improvement and does not address a specific event.

NRC Resident Inspector Position:

The NRC is in agreement with the need to revise guidance on MSPI EDG run hour reporting.

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

NA.

Potentially relevant existing FAQ numbers: NA

Response Section:

Proposed Resolution of FAQ:
It is recommended that the following proposed wording changes or changes with equivalent meaning be incorporated into NEI 99-02.

Licensee proposed wording changes:

Bolded and underlined phrases indicate proposed changes, strike-throughs indicate deletions.

Page F-21: Lines 27 – 32

Run hours (pumps and emergency power generators only) are defined as the time the component is operating. **For pumps, r**~~R~~un hours include the first hour of operation of the component. **For EDGs, exclude all hours before the output breaker is closed (or EDG hours when the EDG is run unloaded) and the first hour after the breaker is closed (the first hour of operation after the breaker is closed is considered part of the load/run demand).** Exclude post maintenance test run hours, unless in case of a failure, the cause of the failure was independent of the maintenance performed. In this case, the run hours may be counted as well as the failure. Pumps that remain running for operational reasons following the completion of post maintenance testing, accrue run hours from the time the pump was declared operable.

FAQ 11-07 (Proposed) – MSPI EDG Fuel Oil Transfer Pumps

Plant: Generic
Date of Event: N/A
Submittal Date: 3/30/11
Licensee Contact: Roy Linthicum, 630-657-3846, roy.linthicum@exeloncorp.com
NRC Contact: Steve Vaughn
Performance Indicator: Mitigating Systems
Site Specific FAQ: No
FAQ requested to become effective: October 1, 2011

Question Section:

NEI 99-02 section F.5 page F-45 provides inconsistent treatment of EDG Fuel Oil Transfer pumps (FOTPs). The FOTPs are identified as being within the system boundary but are not monitored components nor do they contribute to the unavailability unless there is only one pump per EDG. As noted in the guidance, the reason for this treatment is that the FOTP contribution to MSPI was expected to be small. Additional investigation has shown that for some plant configurations, the contribution from the FOTPs could be significant, based on plant design details such as number of pumps, number of EDGs, Day Tank Capacity, cross connect capability, etc. Therefore, appropriate consideration of the FOTPs in MSPI is needed.

Several options for adding the FOTPs to MSPI were investigated, including added the pumps as separate monitored components or considering them within the boundary of the EDG super-component. Based on limitations of the current Consolidated Data Entry software design, it was determined that inclusion of the FOTPs as being with the EDG super-component boundary is the most cost effective option available.

Guidance needing clarification/interpretation:

Revise NEI 99-02 section F.5 and Figure F-1 to include the Fuel Oil Transfer Pumps within the EDG super-component boundary.

Event requiring guidance interpretation:

N/A. This FAQ is for general guidance improvement and does not address a specific event.

NRC Resident Inspector Position:

The NRC is in agreement with the need to revise guidance on the treatment of Fuel Oil Transfer Pumps.

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

NA.

Potentially relevant existing FAQ numbers: NA

Response Section:

Proposed Resolution of FAQ:
It is recommended that the following proposed wording changes or changes with equivalent meaning be incorporated into NEI 99-02.

Licensee proposed wording changes:

Bolded and underlined phrases indicate proposed changes, strike-throughs indicate deletions.

Page F-19, Table 2

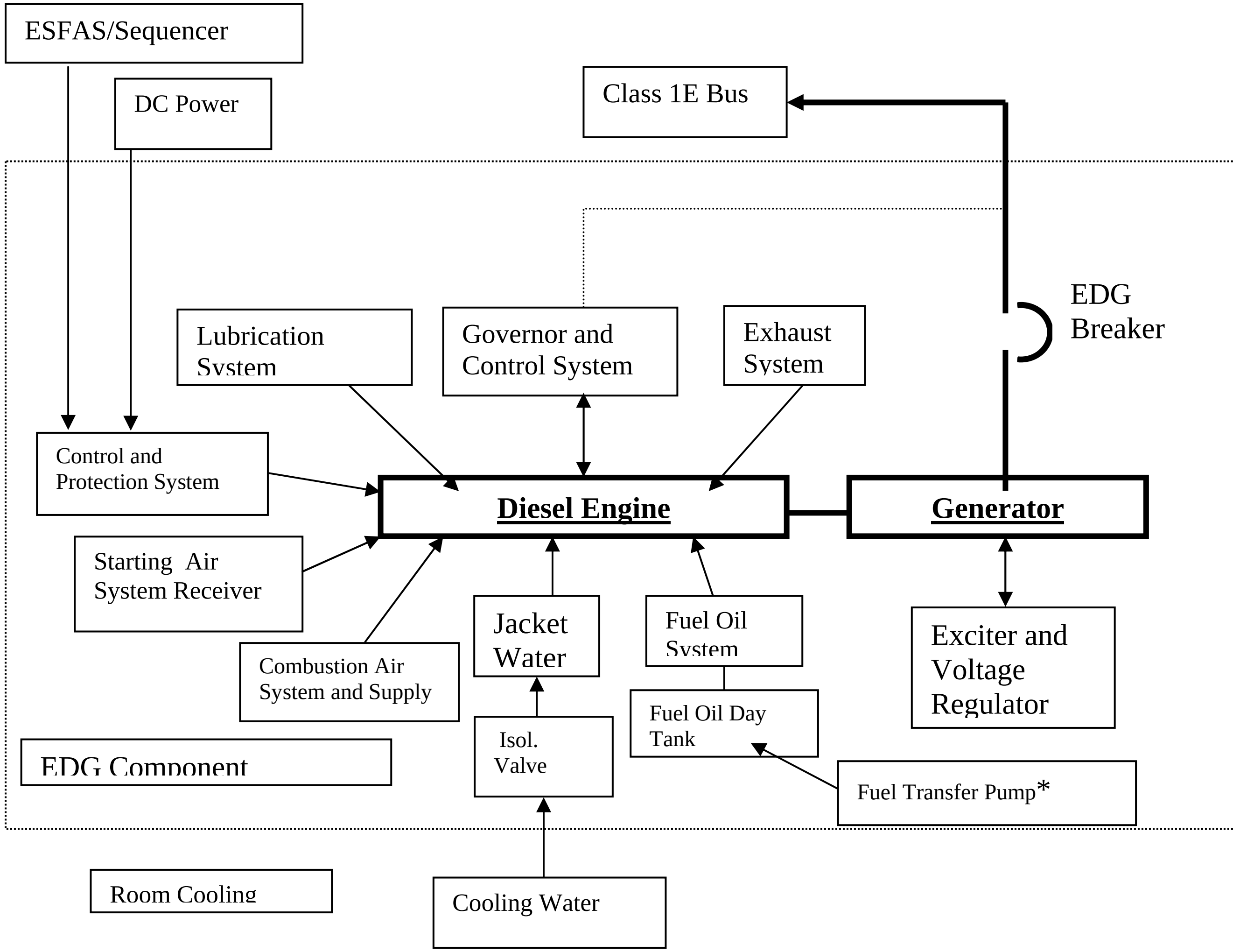
The diesel generator boundary includes the generator body, generator actuator, lubrication system (local), fuel system (local), ***fuel oil transfer pumps***, cooling components (local), startup air system receiver, exhaust and combustion air system, dedicated diesel battery (which is not part of the normal DC distribution system), individual diesel generator control system, cooling water isolation valves, circuit breaker for supply to safeguard buses and their associated control circuit (relay contacts for normally auto actuated components, control board switches for normally operator actuated components

Page F-45: Line 33 – Page F-46 Line 2

The EDG component boundary includes the generator body, generator actuator, lubrication system (local), fuel system (local or day tank ***and fuel oil transfer pumps***), cooling components (local), startup air system receiver, exhaust and combustion air system, dedicated diesel battery (which is not part of the normal DC distribution system), individual diesel generator control system, cooling water isolation valves, circuit breaker for supply to safeguard buses and their associated control circuit. Air compressors are not part of the EDG component boundary.

The fuel transfer pumps required to meet the PRA mission time are within the ***EDG component*** ~~system~~ boundary, but are not considered to be a ***separate*** monitored component for reliability monitoring in the EDG system. Additionally they are monitored for contribution to train unavailability ~~only~~ if ***the fuel oil transfer pump(s) is (are) required to meet the EDG mission time.***~~an EDG train can only be supplied from a single transfer pump. Where the capability exists to supply an EDG from redundant transfer pumps, the contribution to the EDG MSPI from these components is expected to be small compared to the contribution from the EDG itself. Monitoring the transfer pumps for reliability is not practical because accurate estimations of demands and run hours are not feasible (due to the auto start and stop feature of the pump) considering the expected small contribution to the index.~~

Page F-55, Figure F-1



- The Fuel Transfer Pump is included in the EDG ***Component*** ~~System~~ Boundary. See Section 5 for monitoring requirements.

FAQ 11-08 EDG Failure Mode Definitions
(Proposed for Introduction at March 30, 2011 Meeting)

Plant: Generic____________

Date of Event: NA__________________

Submittal Date: March 30, 2011____________

Licensee Contact: Ken Heffner___ Tel/email: 919-546-5688/ken.heffner@pgnmail.com

NRC Contact: _____________ Tel/email: ___________________________________

Performance Indicator: MS06

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):

The Guidance in question begins on page F-25 line 21 and ends on F-26 line 9.

Event or circumstances requiring guidance interpretation:

There is no event driving this requested change to the guidance. The existing definitions for EDG Failure to Start, Load/Run, and Run are confusing and somewhat contradictory. Industry is proposing to change the guidance as described below.

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

NA

Potentially relevant existing FAQ numbers

NA

Response Section

Proposed Resolution of FAQ

Make the changes to the guidance described below.

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

(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:* 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:* Given that it has successfully started, a failure of the EDG output breaker to close, or a failure to run/operate for one hour during surveillance test load sequencing or actual demand. The one hour clock starts at the time that the EDG output breaker closes. During surveillance testing the EDG may not be fully loaded. 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:* 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.) Failures of EDG Fuel Oil Transfer Pumps are considered to be EDG failures to run if the failure of the EDG Fuel Oil Transfer Pump results in failure of the EDG to be able to run for 24 hours.