Enclosure 2
Meeting Summary Handouts
of the August 15, 2011
ROP Public Meeting
Dated July 13, 2011

REACTOR OVERSIGHT PROCESS (ROP)
MONTHLY PUBLIC MEETING AGENDA

July 13, 2011; 9:00 AM – 2:30 PM; Two White Flint North Building;
Conference Room – T-10A1

9:00 – 9:10 AM	Introduction and Purpose of Meeting
9:10 – 9:25 AM	Operating Experience Branch Topics 1. General operating experience topics of interest 2. Discussion of recent staff study on Ineffective Use of Vendor Technical Recommendations 3. Opportunity for public comment
9:25 – 9:40 AM	Inspection Branch Topics 1. General inspection topics of interest 2. Opportunity for public comment
9:40 – 10:15 AM	Performance Assessment Branch Topics 1. General assessment topics of interest 2. Opportunity for public comment
10:15 – 11:00 AM	Discussion of Performance Indicator (PI) Topics 1. PI validity during extended shutdown for Crystal River 2. MSPI topics 3. Opportunity for public comment
11:00 – 11:30 AM	Lunch
11:30 – 2:15 PM	Discussion of 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

March 2, 2011

MEMORANDUM TO: R. W. Borchardt
Executive Director for Operations

FROM: Annette L. Vietti-Cook, Secretary **/RA/**

SUBJECT: STAFF REQUIREMENTS – SECY-10-0121 – MODIFYING THE RISK-INFORMED REGULATORY GUIDANCE FOR NEW REACTORS

The Commission has disapproved the staff's recommendation to modify risk guidance for new reactors as described in SECY10-0121. The Commission has approved a hybrid of Options 1 and 2 as described below. The staff should continue to use the existing risk-informed framework, including current regulatory guidance, for licensing and oversight activities for new plants, at this time, pending additional analysis and review as described below. Substantive changes that would alter the outcomes of the activities below should be made only under specific Commission direction.

The Commission reaffirms that the existing safety goals, safety performance expectations, subsidiary risk goals and associated risk guidance (such as the Commission's 2008 Advanced Reactor Policy Statement and Regulatory Guide 1.174), key principles and quantitative metrics for implementing risk-informed decision making, are sufficient for new plants. Because new plant designs incorporate operating experience from current generation reactors, severe accident research, and risk insights from design probabilistic risk assessments, the Commission expects that the advanced technologies incorporated in new reactors will result in enhanced margins of safety. However, the Commission continues to expect (consistent with the 2008 Advanced Reactor Policy Statement), as a minimum, at least the same degree of protection of the public and the environment that is required for current-generation light water reactors. New reactors with these enhanced margins and safety features should have greater operational flexibility than current reactors. This flexibility will provide for a more efficient use of NRC resources and allow a fuller focus on issues of true safety significance.

In the near-term and coordinated with the below activities, the staff should articulate, in a single document, a coherent overview of the Commission's policies and decisions regarding new reactor safety performance. This document should be written at a summary-level (e.g., a brochure) for purposes of public communication and to supplement NRC staff knowledge management (which would be done separately).

The staff should engage with external stakeholders in a series of tabletop exercises to test various realistic performance deficiencies, events, modifications, and licensing bases changes against current NRC policy, regulations, guidance and all other requirements (e.g., Technical Specifications, license conditions, code requirements) that are or will be relevant to the licensing bases of new reactors. The tabletop exercises should either confirm the adequacy of those regulatory tools (and make the NRC aware of these potential scenarios such that

commensurate regulatory oversight can be applied) or identify areas for improvement, such as potential adjustments to the Reactor Oversight Process.

The staff should continue to work with stakeholders to consider appropriate use of 10 CFR 50.59 by combined license holders and develop guidance for changes during the construction phase and operational phase of a new nuclear power plant that would not require NRC approval. This new plant change control guidance should address severe accident design features and other elements of 10 CFR Part 52 not applicable to operating plants. The staff should assess the sufficiency of regulatory guidance to support combined license holder application of risk-managed technical specifications and potential application of 10 CFR 50.69, *Risk-Informed Categorization and Treatment of Structures, Systems and Components for Nuclear Power Reactors.*

The staff should provide, in the form of Commission Assistant notes or briefings, a schedule of activities followed by progress updates every six months.

The staff should inform the Commission of the results of the above activities. The staff should prepare a notation vote paper with options and recommendations that provide greater specificity and definition than was contained in SECY-10-0121. If the staff concludes that the enhanced safety margins for new plants will significantly decrease without regulatory policy changes, the staff should clearly explain how “significant” (in the context of decreasing safety margins) was defined to support the recommendations.

(EDO) (SECY Suspense: 6/4/12)

cc: Chairman Jaczko
Commissioner Svinicki
Commissioner Apostolakis
Commissioner Magwood
Commissioner Ostendorff
OGC
CFO
OCA
OPA
Office Directors, Regions, ACRS, ASLBP (via E-Mail)
PDR

No.	PI	Topic	Status	Plant/Co.	Point of Contact
10-02 Discussed	IE04	USwC	NRC feedback on the last mark-up was received on 1/19/11. NRC's 6/29/11 mark-up of NEI 99-02 will be discussed. [Discussed 1/20, 2/16, 3/30, 5/4] Industry change 7/12	Generic	Jim Slider (NEI) for the ROP Task Force
10-06 To Be Discussed	MS	Cascading Unavailability	Introduced at October 20 ROP meeting. Discussed 12/1/10. [Tentatively Approved 1/20/11 for Callaway question. In May, the ROP TF prepared a replacement for the body of the Callaway FAQ to present modifications of NEI 99-02 needed to clarify guidance on unavailability.]	Generic	Roy Linthicum (Exelon)
11-01 Expected to be approved-Final at July 13 meeting	MS10	Cooling Water Boundary	Converted from white paper to draft FAQ. Introduced 1/20/11; discussed 1/20, 2/16. Tentatively approved on 3/30. Received NRC comments 7/8/11]	Generic	Jim Peschel (NextEra) Steve Vaughn (NRC)
11-04 To be discussed	IE03	Power Changes Needed to Recover from Loss of Equipment	Converted from white paper to draft FAQ. Introduced at 1/20/11 meeting. [Introduced 1/20, discussed 2/16, 3/30, 5/4] Received NRC comments 6/22/11 Industry change 7/12	Generic	Robin Ritzman (First Energy) Jocelyn Lian (NRC)
11-07 Expected to be approved-Final at July 13 meeting	MS	FOTP Failures	Introduced 3/30/2011. Discussed and tentatively approved at 5/4/11 public meeting. Received NRC edits 7/8/11. Industry change 7/12	Generic	Roy Linthicum (Exelon)

No.	PI	Topic	Status	Plant/Co.	Point of Contact
11-08 Introduced 5/4 To be discussed July 13	MS	EDG Failure Mode Definitions	Introduced 5/4/2011. Received NRC comments 7/8/2011. Industry change 7/12	Generic	Roy Linthicum (Exelon)
11-09 (Proposed) To be introduced 7/13	IE04	Crystal River-3 Extended Shutdown	To be introduced 7/13/2011	CR3/ Progress	Dennis Herrin (Progress) Tom Morrissey (NRC)
11-10 (Proposed) To be introduced 7/13	PP01	Counting of Compensatory Hours for PIDS Upgrade	To be introduced 7/13/2011 [no written FAQ today; to be introduced]	Generic	Dave Gullott (Exelon) NRC Contact TBD
11-11 (Proposed) To be introduced 7/13	EP-03	Ft. Calhoun Alert & Notification System	To be introduced 7/13/2011	Generic	Erick Matzke (OPPD)

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

NRC's Approval of a Revised Effective Date for July 13, 2011 Meeting

NEI 99-02, FAQ 09-10, "Multiple Units at One or More Sites"

Revised to Reflect Final Discussion at ROP Meeting, February 16, 2011
and June 20, 2011 Agreement to Extend Effective Date to Third Quarter 2011

Plant: Tennessee Valley Authority - Sequoyah

Date of Event: 10/19/2009

Submittal Date: Original – 11/9/2009

Licensee Contact: Walt Lee **Tel/email:** whlee@tva.gov

NRC Contact: **Tel/email:**

Performance Indicator:
NEI 99-02, Revision 6, Section 2.4, Emergency Preparedness Cornerstone, Indicator EP01- Drill and Exercise Performance; and Indicator EP02 – ERO Drill Participation.

Site-Specific FAQ (Appendix D)? No, FAQ is Generic.

FAQ requested to become effective: ~~In the quarter following approval~~ Third Quarter 2011.

Question Section

NEI 99-02 Guidance needing interpretation (include page and line citation):
Page 50, Lines 3-13

Purpose

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

Indicator Definition

The percentage of ERO members assigned to fill Key Positions that have participated in a drill, exercise, or actual event during the previous eight quarters, **as measured on the last calendar day of the quarter.** [bolding is in original]

Event or circumstances requiring guidance interpretation:

Multiple Units at One or More Sites

The event or circumstance involves utilities with common Emergency Operations Facilities (EOFs) where the functions of EOF Senior Manager, EOF Key Protective Measures and EOF Communicator are assigned to Key Positions that support multiple nuclear sites. ERO members assigned to each function are grouped and monitored to ensure that each receives a "meaningful opportunity to gain proficiency". These opportunities are accounted for at the end of each quarter and reported through the ROP process.

Where an ERO member is assigned to fill a Key Position supporting multiple nuclear units, the ERO member is trained to support each unit served. Units may be at one site or multiple sites. ERO members receive initial and continuing training on site and unit-specific procedures, processes and protocols as well as involvement in a drill and exercise programs that support both. This ensures the <u>skill sets needed are similar</u> in application regardless of the nuclear unit involved.

The clarification being sought would allow granting of Participation Credit to an ERO member, assigned to fill a Key Position supporting multiple nuclear units, for <u>all</u> the sites served by that member when provided with a meaningful opportunity to gain proficiency during a drill or exercise at <u>any</u> of the supported nuclear units.

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

NRC does <u>not</u> agree with the current method for granting participation credit for common EOFs and has specified that participation credit can be provided only to the specific site involved in the drill or exercise.

Potentially relevant existing FAQ numbers: <u>None identified.</u>

<u>Response Section</u>

Proposed Resolution of FAQ

Revise NEI 99-02, Section 2.4, to provide the option of an alternate methodology that would allow participation credit for the common facility to be counted across all units or sites supported by that facility. The common facility could include an Emergency Operations Facility, Technical Support Center, or Operational Support Center. The alternate methodology could be elected for a common facility serving either multiple units or sites or serving units with different technologies, provided the following five conditions are met:

1. The functions of Classification, Protective Action Recommendations (PARs), Dose Assessment, and Emergency Notifications are performed similarly (an ERO member, assigned to fill a Key Position supporting multiple nuclear units may not

perform all 4 functions, therefore this requirement only applies to the functions performed by that ERO member) for each unit served by the common facility.

2. The link between the Drill and Exercise Performance (DEP) indicator and the ERO Drill Participation indicator is maintained by granting DEP credit (both success and failure) from one drill or exercise to all units served by the common facility.
3. Lessons learned through the common facility are shared with all the nuclear units or sites that are supported by the common facility.
4. Corrective actions associated with Key Positions in the ERO are applied to each unit or site served by the common facility.
5. Initial and continuing position specific training is required for Key ERO positions to include at a minimum all position tasks associated with RSPS. Lesson plans, rosters, records, are available for NRC inspection.

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

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[DRILL AND EXERCISE PERFORMANCE]

NEI 99-02 Revision 6, Section 2.4, page 45, "Clarifying Notes"

If credit for an opportunity is given in the ERO Drill Participation performance indicator, then that opportunity must be included in the drill/exercise performance indicator. For example, if the communicator performing the entire notification during performance enhancing scenario is an ERO member in a Key Position, then the notification may be considered as an opportunity and, if so, participation credit awarded to the ERO member in the Key Position.

[New text to be inserted at Line 38]

If an ERO member in a Key Position supports multiple units (at one or more sites), Drill/Exercise Performance (DEP) opportunities performed by the ERO member may be credited to all sites potentially served by the ERO member, in addition to the specific site participating in the drill or exercise.

When a performance enhancing experience occurs before an individual is assigned to a Key Position in the ERO, then opportunities for that individual that were identified in advance shall contribute to the Drill/Exercise (DEP) metric at the time the member is assigned to the ERO.

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[PARTICIPATION]

NEI 99-02 Revision 6, page 50, "Data Reporting Elements"

[New text to be inserted at Line 24]

The participation indicator may include participation in a facility that supports multiple units.

Calculation

The site indicator is calculated as follows:

NEI 99-02 Revision 6, page 51, "Clarifying Notes"

inspection.

[New text to be inserted at Line 42]

Option for Emergency Response Organizations with Common Facilities

If an ERO member in a Key Position supports multiple units (at one or more sites) and demonstrates similar skill sets during a performance-enhancing experience, participation credit may be granted for all sites supported.

Negative performance credit as well as positive performance credit will be assigned to all units.

Similarity of Skill Sets

Skill sets are considered similar when the procedures, processes and protocols involved accomplish the same task or goal. Examples of similar skill sets are provided below:

Classification

Classification of Emergencies, are similar when Emergency Action Level procedures, processes and protocols used by the ERO members in the Key Position are essentially the same (for example all units would use NEI 99-01 or in the case where a unit may be an advanced passive light water reactor it would be acceptable to utilize NEI 99-01 for existing technology and NEI 07-01 for passive technology). Training for key ERO members performing this function is to include unit-specific and/or technology differences relating to Initiating Conditions/Emergency Action Levels (e.g., ISFSI, unique hazards, design considerations, etc.).

Protective Action Recommendations (PARs)

Protective Action Recommendations, when developed with the same protective action strategies, are similar provided that the procedures, processes and protocols for the development of the protective action recommendations are essentially the same. For example:

- Logic flow charts may differ (e.g., because of population differences among the sites), but should serve the same purpose and be used in the same way.
- Protective Action Zones may differ, but the process used to identify the action taken for the zones is the same.
- Implementation of potassium iodide (KI) strategies may differ based on the implementation strategies of responsible authorities at the State and/or Local level, but the procedures, processes and protocols used to determine if KI is warranted should be the same.
- PAR development discussion strategies should be the same for each site supported by the common facility.

Dose Assessment

Dose assessment is similar when methodologies, applicable computer programs, and models are the same across sites and/or unit technologies served by the common facility. Definitions of what constitutes a radiological release during a classified emergency are the same. Training for key ERO members performing this function must include unit-specific differences in effluent monitors and release pathways, local meteorological regimes and topography impacts and how these differences impact the dose assessment.

Emergency Notifications

The emergency communicator functions are similar when procedures, processes and protocols are performed utilizing a similar emergency notification form design and content. Emergency communicators will be trained on all notification procedures, processes and protocol differences including, but not limited to, offsite contacts, form content, methods and equipment.

Link to Drill and Exercise Performance

Lessons learned (positive and negative) are shared to ensure that the benefits of the performance enhancing experience of the key ERO member(s) are applied across all units. Corrective actions from the performance of key ERO members performing DEP activities are shared with and applied to all key ERO members of all units. Similarly, corrective actions associated with common facility Key ERO member performance (e.g. training or qualification gaps, procedure deficiencies, equipment issues) are applied across all units corrective action programs. DEP opportunities performed shall be credited to all units, in addition to the unit participating in the drill or exercise.

Records

Lesson plans, rosters, records, etc., are available for NRC inspection.

[End of Notes on Option for EROs with Common Facilities]

43 Credit can be granted to Key Positions for ERO Participation for a Security related Drill or

44 Exercise as long as the Key Positions are observed evaluating the need to upgrade to the next

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NRC Response to FAQ:

The staff agrees with the proposed wording changes and with the effective date of 3rd Quarter 2011.

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 of 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 of or inability to recover main feedwater 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 involved the unavailability of or inability to recover main feedwater as determined by the flowchart criteria 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 involved the unavailability of 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 that starts with the ~~onset of the initiating event~~scram and concludes when operators have completed the scram response procedures~~EOP actions~~ and the plant has achieved a stabilized condition in accordance with approved plant procedures and as demonstrated by meeting the following criteria.

For a PWR:

- Pressurizer pressure is within the normal~~nominal~~ operating pressure band.
- Pressurizer level is within the no-load pressurizer band.
- Level and pressure of all steam generators are within the normal operating bands.
- 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).

For a BWR:

- No emergency operating procedure (EOP) entry conditions exist related to either the primary containment or the reactor.
- Reactor cool-down rates are less than 100 degrees F/hr.
- Reactor water level is being maintained within the range specified by plant procedures.

Clarifying Notes

[…]

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 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~~ For plants with design features or procedural prohibitions that prevent restarting Main Feedwater, this question should be answered as "No~~.~~" if MFW is free from damage or failure that would prevent it from performing its intended function and is available for use.

[…]

BWR FLOWCHART QUESTIONS (See Figure 2)

[…]

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. 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.

[…]

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 of 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)

[…]

H 1 PWR Flowchart Basis Discussion

[…]

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

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 MFW is free from damage or failure that can prevent it from performing its intended function and is 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 plant's 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 plant's 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.

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H 3 BWR Flowchart Basis Discussion

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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. 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 *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.

FAQ 10-06
Cascaded Unavailability

Plant: Generic
Date of Event: N/A
Submittal Date: Proposed as 5/4/11
Licensee Contact: Roy Linthicum, 630-657-3846, roy.linthicum@exeloncorp.com
NRC Contact: TBD
Performance Indicator: Mitigating Systems
Site Specific FAQ: No
FAQ requested to become effective: 10/01/2011

Question Section:

Clarification in the guidance is needed 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.

Additional guidance/clarification should be provide 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:

Appendix F, section 1.2.1 regarding the establishment of boundaries between frontline and support system components for reporting unavailability should be revised to be 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" should be revised 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: N/A

NRC Resident Inspector Position: TBD

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:
The following guidance changes should be made to NEI 99-02.

Licensee proposed wording changes:

Page 31 (existing):
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.

Page 31 (revised):
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.

Page 33 (existing):
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 for the system.

Page 33 (revised):

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.

Page 34 (existing):

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. No support systems are to be cascaded onto the monitored systems, e.g., HVAC room coolers, DC power, instrument air, etc.

Page 34 (revised):

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. Other support systems (e.g., HVAC room coolers, DC power, instrument air, etc.) will not be cascaded onto the monitored systems' 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.

Page F-1 (existing):

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.

Page F-1 (revised):

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, the system boundary between the frontline system and the support systems should be considered to be defined as shown in Table 2 and shown in figures F-1 through F-4.

Page F-2 (existing):

Water Sources and Inventory

Water tanks are not considered to be monitored components. As such, they do not contribute to URI. However, 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.

Page F-2 (revised):

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.

Page F-5 (existing):

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 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 functions is included in unplanned unavailability for the time required to recover the monitored function.

Page F-5 (revised):
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 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 functions is included in unplanned unavailability for the time required to recover the monitored function.

Page F-6 (existing):
No Cascading of Unavailability: In some cases plants will disable the autostart of a supported monitored system when the support system is out of service. For example, a diesel generator may have the start function inhibited when the service water system that provides diesel generator cooling is removed from service. This is done for the purposes of equipment protection. This could be accomplished by putting a supported system in "maintenance" mode or by pulling the control fuses of the supported component. If no maintenance is being performed on a supported component and it is only disabled for equipment protection due to a support system being out of service, no unavailability should be reported for the train/segment.
If, however, maintenance is performed on the monitored component, then the unavailability must be counted.

For example, if an Emergency Service Water train/segment is under clearance, and the autostart of the associated High Pressure Safety Injection (HPSI) pump is disabled, there is no unavailability to be reported for the HPSI pump. If a maintenance task to collect a lube oil sample is performed and it can be performed with no additional tag out, no unavailability has to be reported for the HPSI pump. If however, the sample required an additional tag out that would make the HPSI pump unavailable, then the time that the additional tag out was in place must be reported as planned unavailable hours for the HPSI pump.

Page F-6 (revised):
No Cascading of Unavailability: There is no cascading of unavailability from support system components to monitored trains or segments. A failure of a support system component may require a monitored train or segment to be declared Inoperable. If the monitored component is rendered non-functional through tag out or physical plant conditions (other than as discussed

below) then unavailable time should be accrued for the monitored train or segment. Otherwise, unavailability is no accrued.

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 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 train or segment, then the unavailability must be counted.

For example, if an Emergency Service Water train/segment is under clearance, and the autostart of the associated High Pressure Safety Injection (HPSI) pump is disabled, there is no unavailability to be reported for the HPSI pump. If a maintenance task to collect a lube oil sample is performed and it can be performed with no additional tag out, no unavailability has to be reported for the HPSI pump. If however, the sample required an additional tag out that would make the HPSI pump unavailable, then the time that the additional tag out was in place must be reported as planned unavailable hours for the HPSI pump.

Page F-29 (existing):
<u>Failures and Discovered Conditions of Non-Monitored Structures, Systems, and Components (SSC)</u>
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.)

<u>Failures and Discovered Conditions of Non-Monitored Structures, Systems, and Components (SSC)</u>

Page F-29 (revised):
For 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, nor would unavailability be accrued. 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 and unplanned unavailability would be counted against the appropriate train/segment.)

NRC Comments for July 13, 2011 ROP Monthly Meeting

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.

<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.

NRC Comments for July 13, 2011 ROP Monthly Meeting
FAQ TEMPLATE
FAQ 11-01: Cooling Water Boundary (Generic)
Updated 3/7/2011

Revise NEI 99-02, Rev. 6, Page F-52, lines 40 through 43, and Page F-53, lines 1 through 9, to read as follows:

The functions monitored for the cooling water support system are those functions that are necessary (i.e. Technical Specification-required) to provide for direct cooling of the components in ~~the other~~ monitored ~~systems~~trains or segments of systems supported by the cooling water system. It does not include indirect cooling provided by room coolers or other HVAC features.

Systems that provide this function typically include service water and component cooling water or their cooling water equivalents. 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.

Pumps, valves, heat exchangers and line segments that are necessary to provide cooling to ~~the other~~ monitored ~~systems~~ trains or segments of system(s) supported by the cooling water system are included within the cooling water system ~~scope~~ boundary up to, but not including, the ~~last~~ isolation valve(s) that connects the cooling water ~~support~~ system to components in a single monitored ~~system~~ train or segment of the supported system. This ~~last~~ isolation valve is included within the ~~other~~ boundary of the monitored ~~system~~ train or segment of the supported system~~boundary~~. ~~If the~~The last valve(s) that provides cooling to SSCs in more than one monitored ~~system or train~~train or segment of supported system(s)~~, then it~~ is included within the boundary of the cooling water ~~support~~ system. All valves (e.g., manual isolation valves or motor operated valves) in a cooling water line to a single monitored train or segment of a supported system are included within the boundary of the monitored train or segment of the supported system. Figure F-6 depicts this concept and the treatment of multiple isolation valves. The SSCs outside the dashed boxes are included within the boundary of the cooling water system. The SSCs within the dashed boxes are included within the boundaries of the supported systems.~~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.~~

###

Comment [A1]: “Other” systems doesn’t seem as clear as “supported” systems to differentiate between the cooling water system & the systems it supports.

Comment [A2]: This terminology was used to be consistent with the paragraphs below.

Comment [A3]: This was relocated from below, and a new paragraph was created for the valve/component discussion.

Comment [A4]: “Scope” and “boundary” appeared to be used interchangeably, so “scope” was changed to “within the boundary” to be consistent.

Comment [A5]: NEI, please verify this is your understanding. This wasn’t clear to me in the previous write-up that the “monitored train or segment” was that of the cooling water system or the supported system.

Comment [A6]: Because the figure doesn’t specify the SSCs by name or system type, text was proposed in an attempt to make it more obvious.

NRC Comments for July 13, 2011 ROP Monthly Meeting

FAQ TEMPLATE

FAQ 11-01: Cooling Water Boundary (Generic)

Updated 3/7/2011

Cooling Water System Boundary

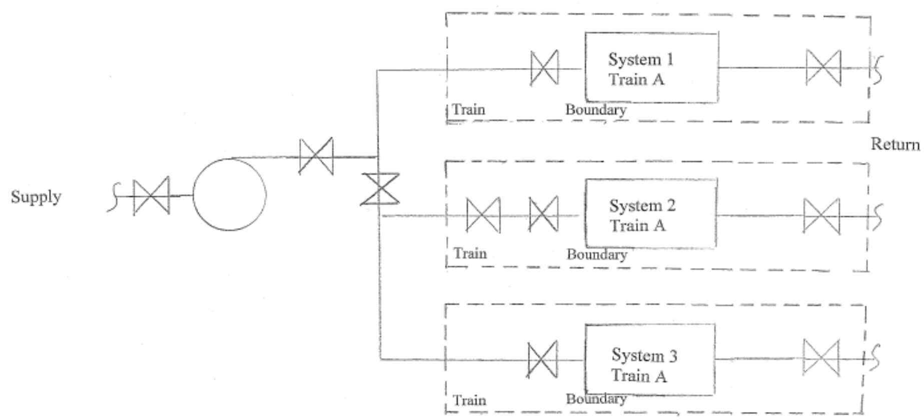

Figure F-6

FAQ TEMPLATE

FAQ 11-04

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~~under the 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~~power reduction ~~-~~to approximately 21% was necessary to establish reactor conditions necessary to restart reactor recirculation pump A and commence power ascension. The power reduction began at 2220 hours on June 4, 2010 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 to a condition with adequate margins to thermal limits and stability in order to re-start the non-operating recirculation pump after repairs are completed. In this case, ~~A~~a power reduction is necessary to reach ~~those~~ this condition~~s~~. 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~~ Unplanned Power Changes per 7,000 Critical Hours PI 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 with this guidance, ~~ntary~~ 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~~approved procedures ~~does not contribute to this indicator either by adding to the magnitude of the initiating event unplanned power change or being counted separately.~~do not count. ~~This~~This exception does not ~~include~~apply to downpowers that are conducted to perform corrective maintenance.

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~~ approved 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 that is evaluated ~~under this criterion~~under this PI.

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 p~~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 approved~~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.~~are excluded.

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 an ~~previously existing~~ approved procedure, the power change(s) (increases or decreases) to restore the equipment to service would not count against this indicator. For example, in BWRs, a power reduction for the purpose of re-starting a recently tripped reactor recirculation pump to re-establish two-loop operation is excluded if the initial power reduction is caused by the recirculation pump trip. The second power reduction to recover the tripped recirculation pump does not count if it is implemented by an approved procedure in response to the initial condition.

NRC's Final Response – July 13, 2011 Handout
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.

The purposes of this FAQ are: (1) to request a one-time exemption from the reporting guidance of NEI 99-02, (2) to request approval for how unavailability and unreliability data will be characterized and reported, and (3) to request approval to revise NEI 99-02, Revision 6, Appendix F, Table 7. This FAQ was submitted because of plant-specific circumstances at Point Beach involving major design changes to the Unit 1 and Unit 2 Auxiliary Feedwater systems that are scheduled to be implemented during the second quarter of 2011. Reference NEI 99-02, Revision 6, Appendix E, page E-1, lines 18 and 19.

<u>Question Section</u>

NEI 99-02 guidance needing interpretation (include page and line criterion):

Point Beach is requesting a one-time exemption from the PI reporting guidance. Specifically, Point Beach wants to know if it is acceptable to gray out MS08, Heat Removal Systems, for the second quarter of 2011 as the results will not be representative of the current PRA and MSPI Document for the quarter.

Point Beach is requesting approval to characterize MS08 data as follows:

- 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 unavailability data (nominally 2002-2004) for the new trains/segments by utilizing the baseline unavailability data for the existing trains/segments, removing the unavailability taken when the other unit was in an outage and averaging the data over three years?
- 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 unavailability for the new trains/segments by utilizing the data for the existing trains/segments removing the unavailability taken when the other unit was in an outage and averaging the data over three years?
- 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?

Finally, Point Beach wants to know if 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.

Event or circumstances requiring guidance interpretation:

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 other 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 Point Beach 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 exemptions above from NEI 99-02 guidance are requested for Point Beach based upon the system design changes being implemented in the second quarter of 2011.

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

The licensee and the NRC agree on the facts.

Potentially relevant existing FAQ numbers:

None

Resolution

Point Beach may have a one-time exemption from the reporting guidance on Page 2, Lines 15-23, of NEI 99-02, Revision 6. The 2Q2011 MS08 PI will be characterized as "Insufficient Data to Calculate PI," as indicated by:

I

on the NRC's "ROP Performance Indicators Summary" Web site because (1) the results will not be representative of the current PRA and MSPI Basis Document for that quarter and (2) the data reflecting the actual plant configuration cannot be processed in CDE software. A comment shall be added to the CDE submittal file explaining the basis for this characterization, which will include that the modification was installed mid-quarter, CDE is not capable of processing a "data split" within the same quarter, CDE does not allow mid-quarter PRA model changes, and an MSPI result for MS08, Heat Removal Systems, reflecting 2Q2011 AF system unavailability and reliability would not be representative of the new system nor provide meaningful results.

AF unavailability and reliability data will be reported to the NRC for 2Q2011. The data will be used for assessing MS08 data for subsequent quarters.

Because the new pumps and associated monitored valves will be similar to the existing pumps and associated monitored valves, Point Beach will determine the baseline unavailability data (nominally 2002-2004) for the new trains by using the unavailability data for the existing trains, removing the unavailability that was reported when the other unit was in an outage, and averaging the data over three years. With respect to historical unavailability data, because the new pumps and associated monitored valves will be similar to the existing pumps and associated monitored valves, Point Beach will determine the past three years of historical unavailability for the new trains by using the data for the existing trains, removing the unavailability taken when the other unit was in an outage, and averaging the data over three years. Point Beach will also update the MSPI basis document at the end of 2Q2011 to reflect the modification's impact on system and train boundaries.

With respect to reliability data, Point Beach will update the device records and associated reliability data in CDE at the time the new pumps and associated monitored valves are placed in service and will update the MSPI basis document at the end of 2Q2011 to reflect the modification's impact on monitored component boundaries. The most recent three years of reliability data for the currently installed pumps will serve as the reliability data for the new pumps because of their similar design and function.

It is acceptable to revise the HRS/MDP Standby generic common cause failure adjustment value from 1.25 to 1.00, which will take effect upon the implementation of the modification, in NEI 99-02, Revision 6, Appendix F, Table 7.

The following text will be added to Appendix D to NEI 99-02:

> 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 other 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 Point Beach 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, exemptions from NEI 99-02 reporting guidance are requested for Point Beach based upon the system design changes being implemented in the second quarter of 2011.

<u>Resolution</u>:

Point Beach may have a one-time exemption from the reporting guidance on Page 2, Lines 15-23, of NEI 99-02, Revision 6. The 2Q2011 MS08 PI will be characterized as "Insufficient Data to Calculate PI," as indicated by:

I

on the NRC's "ROP Performance Indicators Summary" Web site because (1) the results will not be representative of the current PRA and MSPI Basis Document for that quarter and (2) the data reflecting the actual plant configuration cannot be processed in CDE software. A comment shall be added to the CDE submittal file explaining the basis for this characterization, which will include that the modification was installed mid-quarter, CDE is not capable of processing a "data split" within the same quarter, CDE does not allow mid-quarter PRA model changes, and an MSPI result for MS08, Heat Removal Systems, reflecting 2Q2011 AF system unavailability and reliability would not be representative of the new system nor provide meaningful results.

AF unavailability and reliability data will be reported to the NRC for 2Q2011. The data will be used for assessing MS08 data for subsequent quarters.

Because the new pumps and associated monitored valves will be similar to the existing pumps and associated monitored valves, Point Beach will determine the baseline unavailability data (nominally 2002-2004) for the new trains by using the unavailability data for the existing trains, removing the unavailability that was reported when the other unit was in an outage, and averaging the data over three years. With respect to historical unavailability data, because the new pumps and associated monitored valves will be similar to the existing pumps and associated monitored valves, Point Beach will determine the past three years of historical unavailability for the new trains by using the data for the existing trains, removing the unavailability taken when the other unit was in an outage, and averaging the data over three years. Point Beach will also update the MSPI basis document at the end of 2Q2011 to reflect the modification's impact on system and train boundaries.

With respect to reliability data, Point Beach will update the device records and associated reliability data in CDE at the time the new pumps and associated monitored valves are placed in service and will update the MSPI basis document at the end of 2Q2011 to reflect the modification's impact on monitored component boundaries. The most recent three years of reliability data for the currently installed pumps will serve as the reliability data for the new pumps because of their similar design and function

It is acceptable to revise the HRS/MDP Standby generic common cause failure adjustment value from 1.25 to 1.00, which will take effect upon the implementation of the modification, in NEI 99-02, Revision 6, Appendix F, Table 7.

NRC Response to FAQ:

NRC staff agrees with the proposed changes.

NRC Final Response for July 13, 2011 Meeting

FAQ 11-07, FOTP ~~Failures~~

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 and concurrent with FAQ 11-08

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.

NRC Final Response for July 13, 2011 Meeting

Licensee proposed wording changes:

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

Page F-17: Line 37

1) INCLUDE all pumps (except EDG fuel oil transfer pumps ***which are part of the EDG super component***) and diesels

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[1]).

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 (as specified in ~~the first paragraph of~~ Section F.2.2.2 and as defined in the MSPI Definition of Terms section).*** ~~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.~~

((See also EDG failure to run definition in Section F.2.2.2. (FAQ 11-08))

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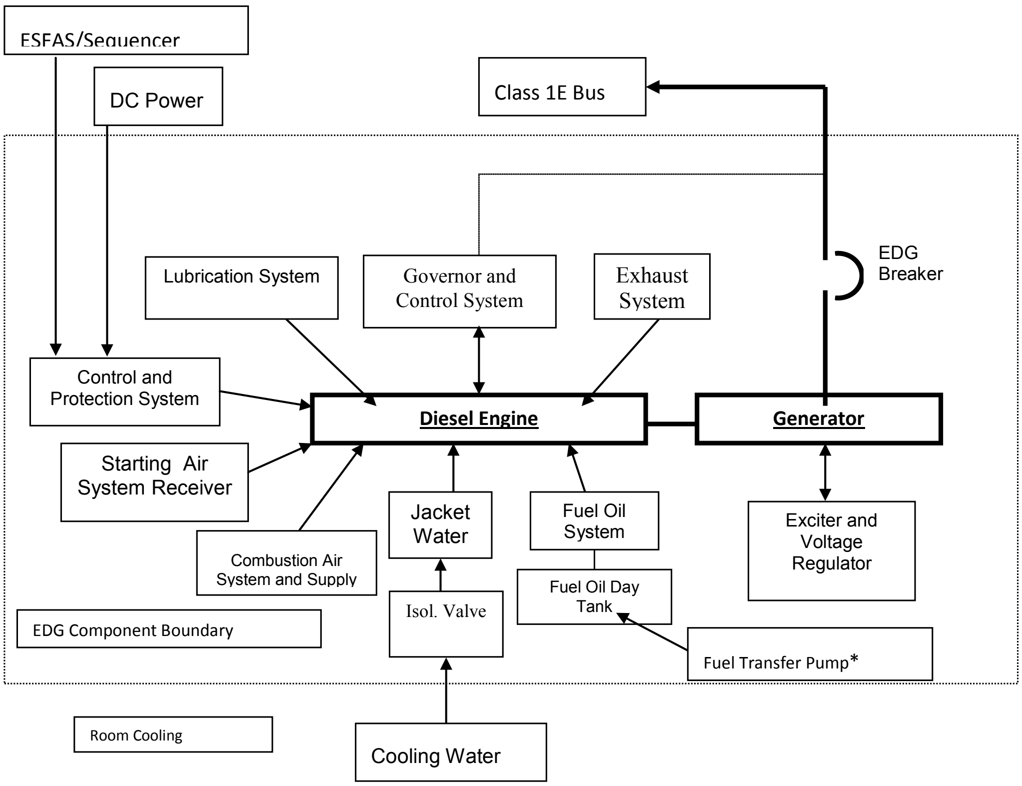
Comment [A1]: NRC wants a stronger tie to where the mission time is defined.

Page F-55, Figure F-1



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

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NRC Response to FAQ:

NRC staff agrees with the proposed changes and the effective date of October 1, 2011.

NRC Comments for July 13, 2011 Meeting

FAQ 11-08, EDG Failure Mode Definitions

Plant: Generic

Date of Event: NA

Submittal Date: March 30, 2011

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

Roy Linthicum Tel/email: 630-657-3846/roy.linthicum@exeloncorp.com

NRC Contact: Audrey Klett Tel/email: 301-415-0489

Performance Indicator: MS06

Site-Specific FAQ (Appendix D)? No

FAQ requested to become effective on 10/01/2011 and concurrent with FAQ 11-07.

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~~is on page F-26, lines 3 through 15, of NEI 99-02, Revision 6.

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. In addition, the failure definitions are being changed to address inclusion of the EDG Fuel Oil Transfer Pumps as being within the scope of the EDG super component boundary.

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 when~~re~~ 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.~~)~~ See the EDG failure to run definition for treatment of ~~F~~fuel ~~O~~oil ~~T~~transfer ~~P~~pump failures.

NRC Comments for July 13, 2011 Meeting

(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:* A failure to load/run is considered (1) the Ffailure of an EDG, given that it has successfully started, (2) a failure of the EDG output breaker to close, or (3) a failure to run/operate for one hour during surveillance test load sequencing or an actual demand is considered a failure to load/run. 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). See the EDG failure to run definition for treatment of Ffuel Ooil Ttransfer Ppump failures.~~

(Proposed) *EDG failure to load/run*: Given that the EDG has successfully started and the output breaker has received a signal to close, a failure of the output breaker to close or a failure to run/operate for one hour after breaker closure. The EDG does not have to be fully loaded to count the failure. 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, provided breaker closure is required by plant design. Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed. See the EDG failure to run definition for treatment of fuel oil transfer pump failures.

Comment [A1]: Does this condition apply to all three situations or just the third situation? If all three, I'd like to make this condition its own sentence.

Comment [A2]: Can this be clarified to provide the context with respect to the failure, or to clarify that this is referring to TS that don't require testing to the design-basis loading? For example:

A failure to load/run also includes the failure of the EDG to reach the loading required by TS surveillance testing or, during an actual demand, the failure of the EDG to reach the design basis loading needed during the first hour of operation.

or

Some plants have TS that allow the loading during surveillance testing to be less than the design-basis loading. For these plants, (1) a failure to load/run also includes the failure of the EDG to reach the loading required by TS surveillance testing, and (2) during an actual demand, a failure to load/run also includes the failure of the EDG to load to the design-basis loading needed during the first hour of operation.

(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:* Ffailure of an EDG, given that: (1) it has successfully started, (2) the output breaker successfully closed, and (3) the EDG has run for an hour after the output breaker closed, is considered a failure 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 the EDG Ffuel Ooil Ttransfer Ppump(s) are considered to be EDG failures to run if the failure of the EDG Ffuel Ooil Ttransfer Ppump results in failure of the EDG to be able to run for 24 hours. This also applies even into those circumstances where the failure determination would be either failure to start or failure to load/run. In the case where a fuel oil transfer pump(s) failure results in loss of capability of more than 1 EDG, a failure is counted for each affected EDG.~~

Comment [A3]: See comment A2 above as applicable to the [24]-hour run.

(Proposed) *EDG failure to run*: A failure after the EDG has successfully started, the output breaker has closed and the EDG has run for an hour after the breaker has closed. The EDG does not have to be fully loaded to count the failure. Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed. Failures of the EDG fuel oil transfer

pump(s) 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 (i.e., no redundant transfer pump is available). Regardless of when the fuel oil transfer pump(s) fails, this counts as a run failure. In the case where a fuel oil transfer pump(s) failure results in loss of capability of more than 1 EDG, a failure is counted for each affected EDG.

FAQ 11-09 (Proposed)
Crystal River-3 Extended Shutdown

Plant: Crystal River Unit 3 (CR-3)
Date of Event: N/A
Submittal Date: June 30, 2011
Licensee Contact: Dennis W. Herrin
Tel/email: 352.563.4633/Dennis.Herrin@pgnmail.com
NRC Contact: Tom Morrissey (CR-3 SRI)
Tel/email: 352.795.6486 (x3265)/Thomas.Morrissey@pgnmail.com

Performance Indicators:
Unplanned Scrams with Complications (IE04)
Mitigating System Performance Index (MS06-MS10)

Site-Specific FAQ (Appendix D)? ■ Yes □ No

In September 2009, CR-3 was taken off line for a refueling outage and for steam generator replacement. During creation of a construction opening in the Containment Building for steam generator replacement, a delamination was created in Bay 3-4 during tendon de-tensioning activities. In mid-March 2011, final re-tensioning of tendons after concrete repair in Bay 3-4 was suspended while engineers investigated evidence of delamination in Bay 5-6 resulting from the tendon re-tensioning work. CR-3 has been shut down since September 2009 and will continue to be shut down into 2013 and perhaps beyond, depending on the repair methodology to be selected. NEI 99-02 does not contain guidance on how to treat certain performance indicators during periods of extended shutdown, or how to recover after returning the unit to service after an extended shutdown.

Because of the unique conditions of this extended shutdown, CR-3 is requesting approval of this FAQ in accordance with NEI 99-02, Revision 6, page E-1, Lines 18-19:

> "3. To request an exemption from the guidance for plant-specific circumstances, such as design features, procedures, or unique conditions."

FAQ requested to become effective when approved.

Request that this FAQ be reviewed on an expedited basis since the CR-3 Service Water System (RW/SW/DC) MSPI performance indicator is currently 62% in the Green Band and declining due to the reduction in critical hours and will cross the green-to-white threshold before reaching an extended shutdown period of three years, without an additional MSPI functional failure.

Question Section

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

Unplanned Scrams with Complications – Clarifying Notes - Page 19
Mitigating System Performance Index – Clarifying Notes – Pages 33 - 35

FAQ 11-09 (Proposed)
Crystal River-3 Extended Shutdown

Event or circumstances requiring guidance interpretation:

Unplanned Scrams with Complications (USwC) is defined as the number of unplanned scrams, while the reactor is critical, both manual and automatic, during the previous 4 quarters that require additional operator actions. After being in a condition where a reactor has not been critical for the previous 4 quarters, no opportunities exist for a USwC and further performance indicator reporting has no meaning. Once a unit exits an extended shutdown and the reactor becomes critical, this performance indicator will immediately have meaning.

Mitigating System Performance Index (MSPI) is defined as the sum of changes in a simplified core damage frequency evaluation resulting from differences in unplanned unavailability and unreliability relative to industry standard baseline values. In order to initially implement these new performance indicators, three years of past operational data had to be base loaded into the INPO Consolidated Data Entry System in order to arrive at the first meaningful calculated value. It can be assumed that an extended shutdown lasting greater than three years renders these performance indicators meaningless. An additional concern is that these performance indicators are sensitive to the reduction in critical hours and may actually become meaningless sooner that an extended shutdown period of three years. A final consideration is that although many of the MSPI monitored components are not required to be operable in NO MODE operation and MSPI functional failure opportunities are minimized, any such failure would be unrealistically weighted and could result in crossing the green-to-white performance indicator threshold.

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

The NRC Senior Resident Inspector agrees with the characterizations above.

Potentially relevant existing FAQ numbers:

No potentially relevant existing FAQs have been located. A review was performed of NRC-approved FAQs and the current listing of Draft FAQs.

<u>Response Section:</u>

Proposed Resolution of FAQ:

The licensee will continue to submit MSPI failure data but MSPI values and Unplanned Scrams with Complications (USwC) data will not be displayed on the NRC website because it is not indicative of plant performance. The USwC indicator will go active when the reactor is critical. A decision on how to determine the best way to reintroduce the MSPI values will be determined prior to plant startup.

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

No revised wording is being proposed.

FAQ 11-11 Alert and Notification System

Plant: Fort Calhoun Station
Date of Event: June 6, 2011
Submittal Date: 7/12/2011
Licensee Contact: Erick Matzke Tel/email: _402-533-6855 / ematzke@oppd.com
NRC Contact: ___________________________ Tel/email: ___________________

Performance Indicator:

Alert and Notification System Reliability (ANS) EP03

Site-Specific FAQ (Appendix D)? Yes

Yes, this would be a Site Specific FAQ (Appendix D)

FAQ requested to become effective when approved or ____________

FAQ requested to become effective for the second quarter 2011 and forward.

Question Section

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

ANS page 57 lines 6 through 10

6 If a siren is out of service for maintenance or is inoperable at the time a regularly scheduled test
7 is conducted, then it counts as both a siren test and a siren failure. Regularly scheduled tests
8 missed for reasons other than siren unavailability (e.g., out of service for planned maintenance or
9 repair) should be considered non opportunities. The failure to perform a regularly scheduled test
10 should be noted in the comment field.

Event or circumstances requiring guidance interpretation:

This document details the decision process for reporting Alert Notification System siren status on NRC Performance indicators during the Flooding event of the spring and summer of 2011.

Under normal circumstances and in accordance with the Fort Calhoun Radiological Emergency Response Plan, section E, sirens are tested bi-weekly for functionality via Emergency Planning Test (EPT) EPT-1 (Alert Notification System Silent Test), quarterly via EPT-2 (Alert Notification System Growl Test), and annually via EPT-3 (Alert Notification System Complete Cycle Test).

Current flooding along the Missouri River and within the 10-mile EPZ has resulted in several sirens being [deliberately] disabled by disconnecting AC power due to rising river levels. These flooding conditions do not only affect the operability/functionality of the sirens, but have also resulted in power disconnections for and evacuation of residents in the areas for which these sirens provide coverage. Additionally, backup route-alerting is still available for any remaining affected residents as verified through local and state governments.

In accordance with NEI 99-02, Revision 6 (Regulatory Assessment Performance Indicator Guideline), page 57 concerning siren testing states "Regularly scheduled tests missed for reasons other than siren unavailability (e.g., out of service for planned maintenance or repair) should be considered non opportunities." This evaluation and exemption was applied to the sirens that have been removed from service due to flooding.

These sirens were removed from service intentionally, and will remain out of service for an extended period of time; therefore will not be counted in the performance indicator for Alert and Notification System Reliability. For all EPTs conducted on sirens during the time period when power has been removed from the siren due to flooding, the number of sirens tested will only be those that have normal power available.

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

The NRC concurs with what is in the FAQ. The NRC indicated that they agreed with our conclusion. (Initial)

Potentially relevant existing FAQ numbers

Grand Gulf Plant Specific FAQ in NEI 99-02 rev 6, appendix D, page D2.

Response Section
Proposed Resolution of FAQ

"Resolution: If sirens are not available for operation due to high flood water conditions and the area is deemed inaccessible and uninhabitable by State and/or Local agencies, the siren(s) in question will not be counted in the numerator or denominator of the Performance Indicator for that testing period."

NRC Final Response for July 13, 2011 Meeting

FAQ 11-07, FOTP ~~Failures~~

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.

NRC Final Response for July 13, 2011 Meeting

Licensee proposed wording changes:

Bolded, *italicized,* and underlined phrases indicate proposed changes, and 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[1]).

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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.

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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 (as specified in the first paragraph of Section F.2.2.2 and as defined in the MSPI Definition of Terms section).*** ~~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.~~

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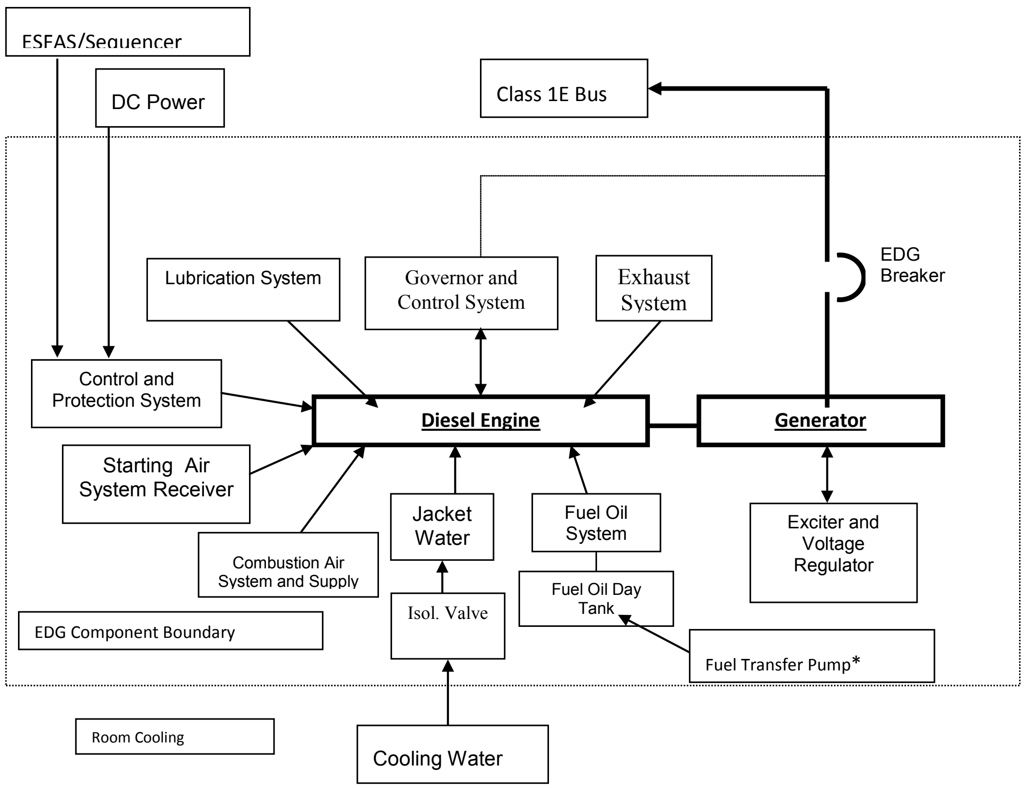
Comment [A1]: NRC wants a stronger tie to where the mission time is defined.

Page F-55, Figure F-1



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

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NRC Response to FAQ:

NRC staff agrees with the proposed changes and the effective date of October 1, 2011.

NRC Comments for July 13, 2011 Meeting

FAQ 11-08, EDG Failure Mode Definitions

Plant: Generic

Date of Event: NA

Submittal Date: March 30, 2011

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

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NRC Contact: Audrey Klett Tel/email: 301-415-0489

Performance Indicator: MS06

Site-Specific FAQ (Appendix D)? No

FAQ requested to become effective on 10/01/2011.

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~~is on page F-26, lines 3 through 15, of NEI 99-02, Revision 6.

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. In addition, the failure definitions are being changed to address inclusion of the EDG Fuel Oil Transfer Pumps as being within the scope of the EDG super component boundary.

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 whe~~re~~n 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.~~)~~ See the EDG failure to run definition for treatment of ~~F~~fuel ~~O~~oil ~~T~~transfer ~~P~~pump failures.

NRC Comments for July 13, 2011 Meeting

*(*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:* A failure to load/run is considered (1) the ~~F~~failure of an EDG~~,~~ given that it has successfully started, (2) a failure of the EDG output breaker to close, or (3) a failure to run/operate for one hour during surveillance test load sequencing or an actual demand ~~is considered a failure to load/run~~. 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~~)~~. See the EDG failure to run definition for treatment of ~~F~~fuel ~~O~~oil ~~T~~transfer ~~P~~pump failures.

(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:* A failure to run/operate is considered a ~~F~~failure of an EDG~~,~~ given that: (1) it has successfully started, (2) the output breaker successfully closed, and (3) the EDG has run for an hour after the output breaker closed~~, is considered a failure 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 the EDG ~~F~~fuel ~~O~~oil ~~T~~transfer ~~P~~pump(s) are considered to be EDG failures to run if the failure of the EDG ~~F~~fuel ~~O~~oil ~~T~~transfer ~~P~~pump results in failure of the EDG to be able to run for 24 hours. This also applies ~~even in~~to those circumstances where the failure determination would be either failure to start or failure to load/run. In the case where a fuel oil transfer pump(s) failure results in loss of capability of more than 1 EDG, a failure is counted for each affected EDG.

Comment [A1]: Does this condition apply to all three situations or just the third situation? If all three, I'd like to make this condition its own sentence.

Comment [A2]: Can this be clarified to provide the context with respect to the failure, or to clarify that this is referring to TS that don't require testing to the design-basis loading? For example:

A failure to load/run also includes the failure of the EDG to reach the loading required by TS surveillance testing or, during an actual demand, the failure of the EDG to reach the design basis loading needed during the first hour of operation.

or

Some plants have TS that allow the loading during surveillance testing to be less than the design-basis loading. For these plants, (1) a failure to load/run also includes the failure of the EDG to reach the loading required by TS surveillance testing, and (2) during an actual demand, a failure to load/run also includes the failure of the EDG to load to the design-basis loading needed during the first hour of operation.

Comment [A3]: See comment A2 above as applicable to the [24]-hour run.