ENCLOSURE 3

MSPI – Action Item 02c
Proposed Clarifications Related to Counting Demands
Revision 1

Some plants noted in the MSPI assessment that the counting of estimated demands appears to require frequent verifications that the estimated demands are within 25% of the actual demands. The comment made was that this limits the potential time savings for counting estimated demands instead of actual demands.

Current Guidance: (Page F-23, lines 32-40)

Estimated demands are not reported to CDE on a periodic (monthly or quarterly) basis, rather, they are entered initially, typically for the period of a refueling cycle (e.g., 48 demands in 24 months) then updated as required. An update is require if a change to the basis for the estimate results in a >25% change in the estimate of the total (operational/alignment + test) value for a group of components within an MSPI system. For example, a single MOV in a system may have its estimated demands change by greater than 25%, but revised estimates are not required unless the total number of estimated demands for all MOVs in the system changes by >25%. The new estimate will be used in the calculation the quarter following the input of the updated estimates into CDE.

Proposed Guidance Clarification:

Estimated demands are not reported to CDE on a periodic (monthly or quarterly) basis, rather, they are entered initially, typically for the period of a refueling cycle (e.g., 48 demands in 24 months) then updated as required. An update is require if a change to the basis for the estimate results in a >25% change in the estimate of the total (operational/alignment + test) value for a group of components within an MSPI system **over the estimating period**. For example, a single MOV in a system may have its estimated demands change by greater than 25%, but revised estimates are not required unless the total number of estimated demands for all MOVs in the system changes by >25%. **As an additional example, actual demands for a group of components may vary from the estimates within a quarter by >25%; however, revision of the estimate is not required unless the actual demands are projected to vary by >25% over the entire estimating period (i.e., the period used in CDE),** The new estimate will be used in the calculation the quarter following the input of the updated estimates into CDE.

ENCLOSURE 4 MSPI-03

Proposed change to NEI 99-02 to address "time of discovery"

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

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

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

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

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

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

Recommended Changes.

- Page 29, section titled Indicator Definition, second paragraph, line 20. Add the following sentence after the last sentence (in the parentheses) of the second paragraph; "Time of discovery of a failed monitored component is when the licensee determines that a failure has occurred or when an evaluation determines that the train would not have been able to perform its monitored function(s)." In any case where a monitored component has been declared inoperable due to a degraded condition, if the component is considered available, there must be a documented basis for that determination. Delays in initiating or completing evaluations of degraded conditions would be addressed through the inspection process.

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

ENCLOSURE 5

Action Item MSPI-05

Proposed changes to NEI 99-02 to address "failures identified during post maintenance tests"

Background –Issue A

The survey respondents have requested additional clarity on how to count demands that are associated with Post Maintenance Test (PMT) activities. For example, if a component is run to support a PMT on a non-monitored component, should this demand on the monitored component be counted as an operational demand, or should it be considered as a PMT demand and be excluded (unless a failure occurs)? An example might be a pump run following a leak repair, in which the repaired component is a non-monitored component. Since no maintenance was performed on the pump, this might be considered an operational alignment, even though it is performed for the purpose of PMT on another component.

Recommended Change to NEI 99-02,

Page F-21, lines 7-13 – Revise as follows:

> Demands (including start demands for the emergency power generators) are defined as any requirements for the component to successfully start (pumps and emergency power generators) or open or close (valves and circuit breakers). Exclude post maintenance test demands **performed following maintenance on a monitored component**, unless in case of a failure, the cause of the failure was independent of the maintenance performed. In this case the demand may be counted as well as the failure. Post maintenance tests are tests performed following maintenance but prior to declaring the train/component operable, consistent with Maintenance Rule implementation.

Background – Issue 2

The survey respondents requested a revision to the guidance for reporting maintenance induced failures caused by damage or other issues caused by the maintenance activity and identified during PMT performed prior to restoring the component to functional status. The survey guidance matches the concerns raised during the reviews and appeal of FAQ 428. The conduct of maintenance activities involves numerous support activities during which a failure may be introduced. These failures will most likely be identified during the post maintenance testing and are not independent of the maintenance performed. Therefore they should not be counted as they are **not** indicative of the reliability of the equipment that was undergoing maintenance.

Recommended Change to NEI 99-02

Page F-26, line 34 - Insert the following new section

> Treatment of failures discovered during post maintenance tests:

Failures identified during post-maintenance tests (PMT) are not counted unless the cause of the failure was independent of the maintenance performed. The maintenance performed includes all the activities required to be performed to conduct and support the maintenance, including support activities, the actual maintenance activities, and all activities required for restoration of the monitored component(s) to their available and operable condition. This includes, but is not limited to, typical tasks such as scaffolding erection and removal, coatings applications, insulation removal and installation, rigging activities, health physics activities, interference removal and restoration, as required to support and perform the required maintenance activity. System or component failures introduced during these activities are not indicative of the reliability of the equipment, since they would not have occurred had the maintenance activity not been performed. Such failures are not counted providing they are identified during or prior to the post-maintenance testing and are corrected prior to the component(s) being returned to functional status, with the repair documented in a work package. Support activities may be planned, scheduled and implemented on separate work orders from the work order for the monitored component(s).

ENCLOSURE 6

MSPI-06

For MSPI monitored components, the duty cycle (demand or run hour) categories shown in Table 3 are reported to CDE to support the URI derivation.

Table 3. Required Duty Cycle Categories by Component Type

Component Type	Duty Cycle Categories Required
All valves and circuit breakers	Demands
All pumps	Demands Run Hours
All Emergency Power Generators (both diesel and hydro electric)	Start Demands Load Run Demands Run Hours

Demands (including start demands for the emergency power generators) are defined as any requirements for the component to successfully start (pumps and emergency power generators) or open or close (valves and circuit breakers). Exclude post maintenance test demands, unless in case of a failure, the cause of the failure was independent of the maintenance performed. In this case the demand may be counted as well as the failure. Post maintenance tests are tests performed following maintenance but prior to declaring the train/component operable, consistent with Maintenance Rule implementation. Some monitored valves will include a throttle function as well as open and close functions. One should not include every throttle movement of a valve as a counted demand. Only the initial movement of the valve should be counted as a demand. Demands for valves that do not provide a controlling function are based on a full duty cycle.

Load run demands (emergency power generators only) are defined as any requirements for the output breaker to close given that the generator has successfully started and reached rated speed and voltage. Exclude post maintenance test load run demands, unless in case of a failure, the cause of the failure was independent of the maintenance performed. In this case, the load run demand should be counted, depending on whether the actual or estimated demand method will be used, as well as the failure.

Run hours (pumps and emergency power generators only) are defined as the time the component is operating. Run hours include the first hour of operation of the component. Exclude post maintenance test run hours, unless in case of a failure, the cause of the failure was independent of the maintenance performed. In this case, the run hours may be counted as well as the failure. Pumps that remain running for operational reasons following the completion of post maintenance testing accrue run hours from the time the pump was declared operable.

ENCLOSURE 7

Proposed text:

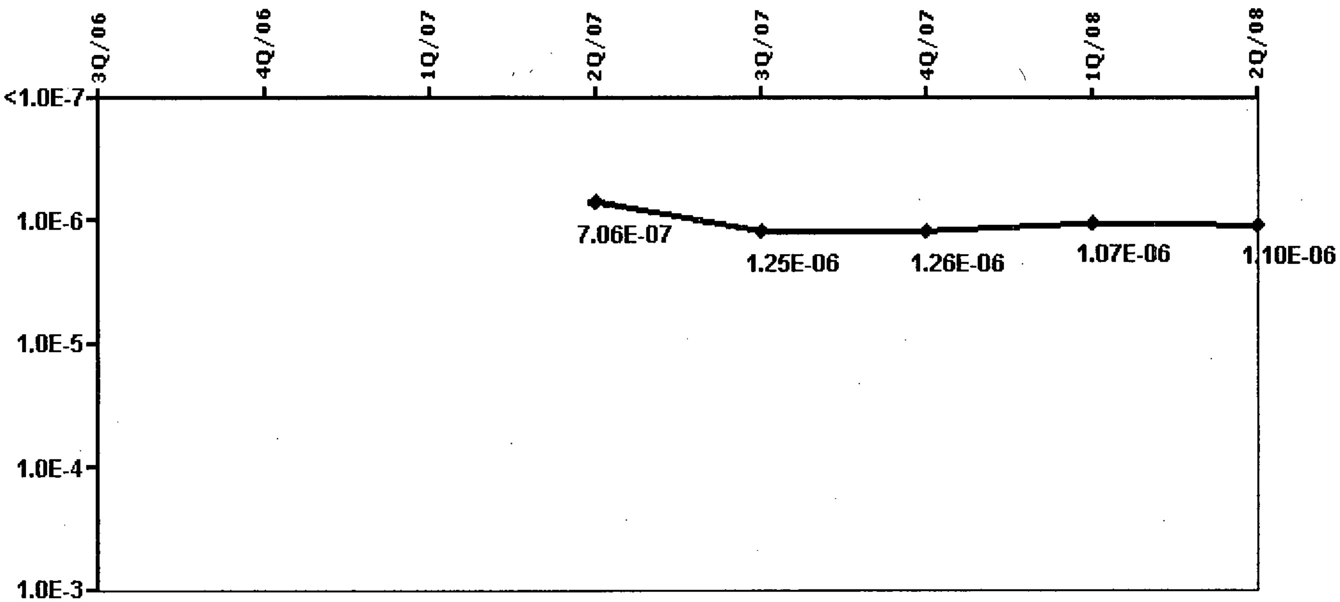
Anticipated power changes greater than 20% in response to expected environmental problems (such as accumulation of marine debris, biological contaminants, or frazil icing) may qualify for an exclusion from the indicator. The licensee is expected to take reasonable steps to prevent intrusion of marine or other biological growth from causing power reductions. Intrusion events that can be anticipated as a part of a maintenance activity or as part of a predictable cyclic behavior would normally be counted, unless the down power was planned 72 hours in advance or the event meets the guidance below.

In order for an environmental event to be excluded, consider the following:

- If the conditions have been experienced before and they exhibit a pattern of predictability or periodicity (e.g., seasons, temperatures, weather events, etc.), the station must have a monitoring procedure in place for the event to be considered for exclusion from the indicator.
- If monitoring identifies the condition, there must be a proactive procedure (or procedures) to specifically address mitigation of the condition before it results in impact to operation. This procedure cannot be a general Abnormal Operating Procedure (AOP) addressing the consequences of the condition (e.g., low condenser vacuum); rather, it must be a condition-specific procedure that direct actions to be taken to address the specific environmental conditions (e.g., jellyfish, gracilaria, frazil ice, etc.)
- Environmental conditions that are unpredictable may not need to count if the licensee has taken appropriate actions and equipment is fully functional at the time of the event.
- Unique environmental conditions which are truly unique and have not been previously experienced may be excluded. This determination is independent of how long ago previous conditions may have occurred and whether previous conditions were of a magnitude to cause plant operational impacts.

The circumstances of each situation are different and if the above guidance does not clearly resolve the determination, the event should be identified to the NRC in a FAQ so that a decision can be made concerning whether the power change should be counted.

Mitigating Systems Performance Index, Emergency AC Power System



Thresholds: White > 1.00E-6 Yellow > 1.00E-5 Red > 1.00E-4

Notes

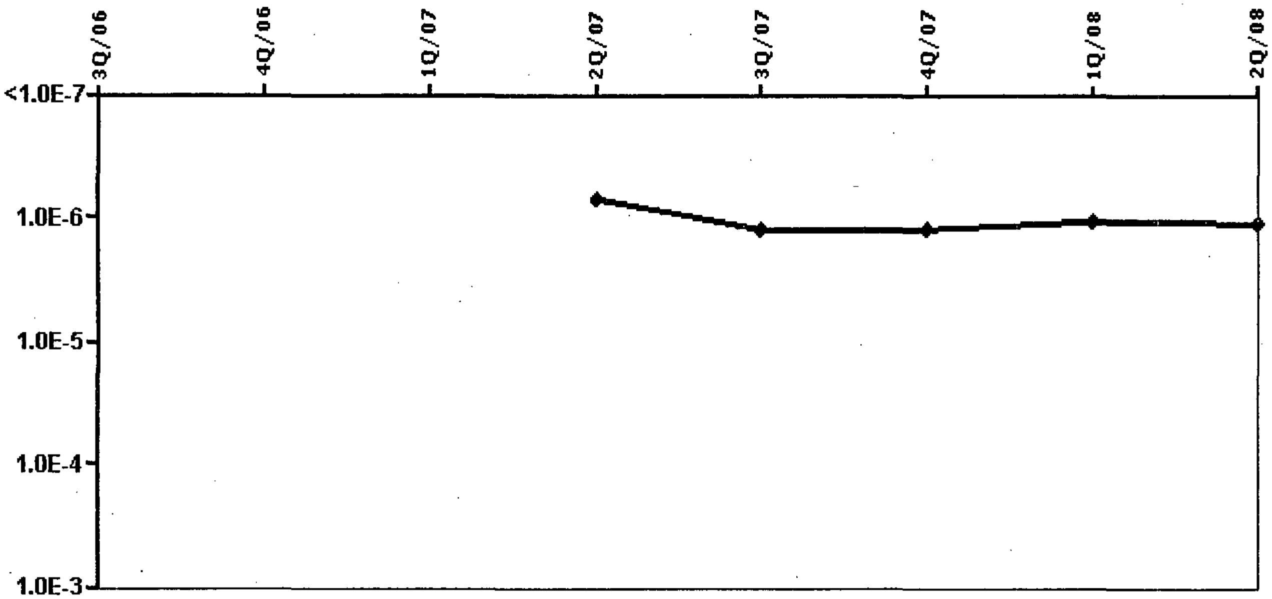
Mitigating Systems Performance Index, Emergency AC Power System	3Q/06	4Q/06	1Q/07	2Q/07	3Q/07	4Q/07	1Q/08	2Q/08
UAI (ΔCDF)				5.60E-08	4.90E-08	5.80E-08	7.00E-08	9.80E-08
URI (ΔCDF)				6.50E-07	1.20E-06	1.20E-06	1.00E-06	1.00E-06
PLE				NO	NO	NO	NO	NO
Indicator value				**7.06E-07**	**1.25E-06**	**1.26E-06**	**1.07E-06**	**1.10E-06**

Licensee Comments:

2Q/08: Browns Ferry Unit 1 quarterly data entry began with 2nd Quarter 2007. Data reported since 2nd quarter 2007 reflects a lack of historical operational data needed to maintain an adequate degree of accuracy required by this PI. Until further notice performance threshold crossings will be assessed by the NRC baseline & supplemental inspection programs.

ENCLOSURE 8

Mitigating Systems Performance Index, Emergency AC Power System



Thresholds: White > 1.00E-6 Yellow > 1.00E-5 Red > 1.00E-4

Notes

Mitigating Systems Performance Index, Emergency AC Power System	3Q/06	4Q/06	1Q/07	2Q/07	3Q/07	4Q/07	1Q/08	2Q/08
UAI (ΔCDF)				5.60E-08	4.90E-08	5.80E-08	7.00E-08	9.80E-08
URI (ΔCDF)				6.50E-07	1.20E-06	1.20E-06	1.00E-06	1.00E-06
PLE				NO	NO	NO	NO	NO
Indicator value				**7.06E-07**	**1.25E-06**	**1.26E-06**	**1.07E-06**	**1.10E-06**

Licensee Comments:

2Q/08: Browns Ferry Unit 1 quarterly data entry began with 2nd Quarter 2007. Data reported since 2nd quarter 2007 reflects a lack of historical operational data needed to maintain an adequate degree of accuracy required by this PI. Until further notice performance threshold crossings will be assessed by the NRC baseline & supplemental inspection programs.

ENCLOSURE 9

TempNo.	PI	Topic	Status	Plant/ Co.
75.2	IE01	Appx 5% Unplanned Power change during Shutdown to Repair valve	12/05 Introduced and discussed 1/16 Discussed 2/20 Tentative Approval	Perry
76.0	IE03	Discovery of an Off-normal condition	1/16 Introduced and discussed 2/20 Discussed	Quad Cities
76.1	IE03	Cladophora Algae Intrusion Event on 10/13	1/16 Introduced and discussed 2/20 Discussed	FitzPatrick
76.2	IE03	Cladophora Algae Intrusion Event on 11/6	1/16 Introduced and discussed 2/20 Discussed	FitzPatrick
76.3	MS06	EDG Pressure Switch Failure	1/16 Introduced and discussed 2/20 Tentative Approval	Byron
77.0	IE03	Grassing Event	2/20 Introduced and discussed	Salem
78.1	IE03	Storm Induced Marine/Biological Intrusion	2/20 Introduced and discussed	Diablo Canyon
79.0	IE03	Over-Voltage due to Lightening	3/19 Introduced	Robinson
79.1	PP02 & PP03	Removal of Security PIs	3/19 Introduced and Discussed	Generic
79.2	IE03	Threadfin Shad Run	3/19 Introduced and Discussed	Brown's Ferry
79.3	IE03	Historical Downpowers	3/19 Introduced and Discussed	Brown's Ferry

Plant: Perry
Date of Event: June 22, 2007
Submittal Date: ____________________
Contact: Robin Ritzman Tel/email 330-384-5414, rritzman@firstenergycorp.com
NRC Contact: Mark Franke Tel/email: 440-280-5822

Performance Indicator: IE-3 Unplanned Power changes

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):
At various places throughout the guidance, NEI 99-02 indicates that one of the criterion used to determine if a power change that is counted in this indicator occurred is if the power change exceeded 20%. This FAQ is being submitted to determine if an unplanned power change exceeding 20% occurred.

Event or circumstances requiring guidance interpretation:
On June 21, 2007, a planned plant shutdown was commenced with the intent of completing the shutdown with a manual scram. The purpose of the shutdown was to repair a valve associated with a reactor recirculation pump. This issue was discovered on June 4, 2007.

At approximately 0100 on June 22, 2007, at approximately 43.1% core thermal power (43.6% neutron flux), Operations performed an "A" and "B" Reactor Recirculation Pump downshift. At this point, Operations expected to observe a power reduction of approximately 12%. The "B" Reactor Recirculation Pump tripped instead of shifting to slow speed. This resulted in a power change that dropped to approximately 26.1% core thermal power (21.6% neutron flux), leveling out at approximately 26.1% core thermal power (23.3% neutron flux). A thermal power graph that was subsequently obtained from the plant computer indicates that power briefly increased from approximately 43.1% power to approximately 46.9% power before the power decrease. Reactor Engineering believes that the brief indicated power increase was indication only and does not reflect actual power level. Average Power Range Monitors indicated a neutron flux change of 22.0% during this transient.

The shutdown was then completed with a planned manual scram from approximately 23% in accordance with normal plant procedures. This scram was not counted as it was completed in accordance with normal plant procedures, but is the subject of another FAQ.

This was not counted as an Unplanned Power Change because the power change met the 72-hour criterion established on NEI 99-02, Rev 4, page 16, line 40, through page 17, line 4. Lines 10 through 14 state that equipment problems encountered during a planned power reduction greater than 20% that alone may have required a power reduction of 20% or more to repair are not counted as part of this indicator if they are repaired during the planned power reduction. However, if during the implementation of a planned power reduction, if power is reduced by more than 20% of full power beyond the planned reduction, then an unplanned power change has occurred. In this case, power was not reduced by more than 20% of full power beyond the planned reduction. Therefore, FENOC does not believe that this power change counts toward the indicator because the unplanned portion of the evolution was not more than approximately 10%. This is similar to FAQ 2, which is reflected on page 17, lines 12 – 14, of NEI 99-02, Rev 4. These lines were added in Rev 1, while incorporating the FAQ resolution.

Should an unplanned power change be counted and reported under IE-3?

If licensee and NRC resident/region do not agree on the facts and circumstances, explain
The licensee and the NRC resident inspector agree on the facts described in this FAQ. However, the NRC senior resident inspector believes that it should count as an unplanned power change because the nuclear instrument and the thermal power history graphs indicated a power change greater than 20% coincident with the pump failure.

Potentially relevant existing FAQ numbers
FAQ 2 (below) is a potentially relevant FAQ, clarifying that only the reactor power change in excess of the expected change needs to be considered for an unplanned power change.

FAQ 2 Question If a licensee plans to reduce from 100% to 85% (15% reduction) but due to equipment malfunction (boron dilution) overshoots and reduces to 70%. Since 15% was already planned, is the overall transient considered (100-70 = 30% and counted as a "hit"), or is it only for transients beyond that planned (85-70 = 15% and not counted as a "hit")?

FAQ 2 Response The Unplanned Power Changes Performance Indicator addresses changes in reactor power that are not an expected part of a planned evolution or test. In the proposed example, the unplanned portion of the power evolution resulted in a 15% change in power and would not count toward the performance indicator.

Response Section

Proposed Resolution of FAQ

Since the unexpected portion of this unplanned power change was not more than approximately 10% of full reactor power, it should not count toward the Unplanned Power Change PI.

If appropriate, provide proposed rewording of guidance for inclusion in next revision.
No revision to the guidance is required.

Plant:	Quad Cities Station		
Date of Event:	9-4-07		
Submittal Date:	1-3-07		
Licensee Contact:	James "Dave" Boyles	Tel/Email:	309-227-2813 james.boyles@exeloncorp.com
NRC Contact:	Karla Stoeder	Tel/Email:	309-227-2850

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

Site-Specific FAQ (Appendix D)? No

FAQ requested to become effective when approved or ______________________

When Approved.

Question Section

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

The difference between a "planned" and an "unplanned" power change is determined by whether or not the power change was initiated less than 72 hours following the discovery of an off-normal condition. The starting point of the 72-hour clock is the subject of this interpretation.

Page 13
Line Citation 25 and 26

Event or circumstances requiring guidance interpretation:

A High Pressure Coolant Injection (HPCI) steam supply valve, located in the drywell, tripped during motor-operated valve surveillance testing. The trip occurred at 0500 on 9-4-07. Subsequent troubleshooting led to the decision to perform a shutdown to repair the valve. This decision was made @ 2300 on 9-4-07. The unit power was reduced 20% @ 2130 on 9-7-07.

If the 72-hour clock starts at 0500 on 9-4-07, when the valve trip occurred, then the power change is classified as planned. If the 72-hour clock starts at 2300 on 9-4-07, when the decision was made to perform the power change to support the valve repair, then the power change is classified as unplanned.

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

The guidance requires the clock to start when there is "discovery" of an off normal condition that results in, or requires a change in power level of greater than 20% of full power. The NRC resident believes that the "discovery", was not made until troubleshooting had progressed to the point that a decision was made to perform a drywell entry, and therefore a power reduction was required. If, for example, the valve had tripped from a breaker-related issue, the plant power reduction would not have been required. Therefore, the station did not know enough specific information about the valve trip to start the 72-hour clock until troubleshooting had revealed the need to enter the drywell.

The licensee believes that the trip of the valve is the "discovery" of the off-normal condition and therefore is the start of the clock.

Potentially relevant existing FAQ numbers:

277, 334, 399

Response Section

Proposed Resolution of FAQ

The key word that creates the point of contention is the use of the phrase "discovery of an off-normal condition". The off-normal condition was the inability to move the valve due to the breaker trip. The condition that caused the trip, which may or may not have required a power change greater than 20%, does not change the time that the off-normal condition was discovered. The clarifying notes in NEI 99-02, states that the 72-hour period is "based on the typical time to assess the plant condition, and prepare, review, and approve the necessary work orders, procedures, and necessary safety reviews to effect a repair." The difference between the valve trip and determination of the actual proper repair required, is captured by the "typical time to assess" phrase in this clarification.

Review of archived FAQs, show examples where the off-normal condition did not immediately result in a power reduction. In the resolution of the FAQ examples, the following applicable items are similar. Example 334, cites that a "problem solving team was formed to evaluate options" which is similar to performing troubleshooting to determine the exact cause of the valve trip. Example 227, cites a condition that matured (leak rate increased) and also did not create a new discovery date when the decision was made to perform the power reduction once the threshold leak rate had developed. Example 399, cites multiple repair attempts to solve a problem and this also did not reset the original discovery date. In each of these examples, the discovery date was simply the date when the off-normal condition occurred.

Based on the clarifying notes in NEI 99-02 and the similarity of the approved existing FAQs, it is reasonable to conclude that this power reduction was not an unplanned reduction.

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

Plant: James A. FitzPatrick Nuclear Power Plant Rev. 1
Date of Event: 10/13/07
Submittal Date:
Licensee Contact: Gene Dorman **Tel/email:** (315) 349-6810/ edorman@entergy.com
Licensee Contact: Jim Costedio **Tel/email:** (315) 349-6358/ jcosted@entergy.com
NRC Contact: Gordon Hunegs **Tel/email:** (315) 349-6667/gkh@nrc.gov

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

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

FAQ requested to become effective when approved.

<u>Question Section:</u>

NEI 99-02 Rev 5 Guidance needing interpretation (include page and line citation):

Unplanned Power Changes Per 7,000 Critical Hours, beginning at the bottom of page 14 at line 42 and continuing on to the top of page15 through line 4, the guidance document states:

42 Anticipated power changes greater than 20% in response to expected environmental problems
43 (such as accumulation of marine debris, biological contaminants, or frazil icing) which are
44 proceduralized but cannot be predicted greater than 72 hours in advance may not need to be
45 counted unless they are reactive to the sudden discovery of off-normal conditions. However,
46 unique environmental conditions which have not been previously experienced and could not
47 have been anticipated and mitigated by procedure or plant modification, may not count, even if
48 they are reactive. The licensee is expected to take reasonable steps to prevent intrusion of marine
49 or other biological growth from causing power reductions. Intrusion events that can be

1 anticipated as a part of a maintenance activity or as part of a predictable cyclic behavior would
2 normally be counted unless the down power was planned 72 hours in advance. The
3 circumstances of each situation are different and should be identified to the NRC in a FAQ so
4 that a determination can be made concerning whether the power change should be counted.

Event or circumstances requiring guidance interpretation:

On October 13, 2007 the Operations Department initiated a plant shutdown from 100% power due to an intrusion of Cladophora Algae (CR-JAF-2007-03580). This event was similar to the event on September 12, 2007 that resulted in the operations staff inserting a manual scram (CR-JAF-2007-03202). Since the Root cause evaluation had not been completed on the September event, long term corrective actions had not been implemented, however, interim corrective actions documented in Operations Shift Standing Order (OSSO) 2007-020 were in place at the time of the October event.

Interim corrective actions included:
<u>Monitoring Requirements</u>:

<u>Control Room:</u>
- Trend Screenwell level on EPIC Log 1 or the "1PLOTC" EPIC trend plot.
- Monitor Traveling Screen Differential Level (36DPI-111) and Trash Rack Differential Level (36DPI-112) frequently.
- Monitor B2 Condenser water box differential pressure (36DPI-101B2) frequently.
- Monitor Condenser Water Box differential temperatures.
- Monitor RHRSW and ESW pump flow rate for degradation when in service.

<u>In Plant:</u>

- When the Traveling Screens are in continuous mode inspect Traveling Screen performance locally every 2 hours.
- Monitor Normal Service Water pump strainer differential pressure every 4 hours when associated pump is in operation. (46DPS-131A & 46DPS-131B alarm at 5 psid. 46DPS-131C alarms at 7 psid.)
- Monitor RHRSW and ESW discharge strainer dP once per hour when these pumps are in service.

Contingency Actions:

- Fire hose station is available for traveling screen manual cleaning.
- Maintain the debris basket clean of accumulated debris.
- Ensure a spare debris basket is available.

Other Conditions and Actions:

High Wind Conditions (sustained > **20** mph @ 30 ft.):

- Ensure all three Traveling Screens are in the continuous run mode.
- Monitor traveling screen performance and debris basket quantity every 30 minutes.
- If significant lake debris is incoming, continuously monitor traveling screen performance, debris basket quantity, and intake level.

Indication of Degraded Traveling Screen Performance:

- With the screens rotating and indication of rising screen dP, initiate manual cleaning using fire hoses. Remove access panels as required.
- Closely monitor Traveling Screen differential pressure.
- Enter AOP-56 (High Traveling Screen and Trash Rack Differential Level) and monitor rate of change.

Indication of Lowering Screenwell Intake Level (>0.3 feet):

- With any indication of lowering lake level, enter AOP-64 (Loss of Intake Water Level)
- Closely monitor rate of change of Screenwell intake level for determining mitigating actions.

Receipt of Service Water Pump Strainer dP Alarms:

- Execute ARP-09-6-2-33 (SERV WTR PMP STRAINER DIFF PRESS HI).
- Ensure applicable strainer is rotating and flush valve is full open.
- Place all operating Service Water Pump strainers in manual backwash until dP is less than 5 psid.
- Inspect Screenwell intake for debris and ensure Traveling Screens are in continuous mode until it is confirmed that there is no debris input from the lake.

Actions for a Main Circulating Pump Start:

- Ensure all Traveling Screens are in continuous mode.
- Do not start additional Main Circulating pumps unless Traveling screen dP is less than 2"H2O.
- Monitor condenser water box differential pressure and temperatures for the subsequent hour.
- Monitor Screenwell intake level for unexpected level change.

Actions during Emergency Service Water and RHRSW Pump Operation:

- When RHRSW pumps are initially started, monitor strainer dP and motor cooling flow for the first 15 minutes. Then monitor strainer dP hourly for the next eight hours of pump operation to determine if a degrading trend exists. After 8 hours, monitor every 4 hours. (10DPIS-277A/B alarm at 7 psid)
- When ESW pumps are initially started, monitor strainer dP and motor cooling flow for the first 15 minutes. Then monitor strainer dP hourly for the next eight hours of pump operation to

determine if a degrading trend exists. After 8 hours, monitor every 4 hours. (46DPS-132A/B alarm at 4.0 psid)

- Monitor RHRSW and ESW pump flow rate for degradation on EPIC when pumps are operating.

On October 13, 2007during a high wind event these actions were implemented but were inadequate to prevent clogging of the traveling water screens (TWS). Once clogged the TWS motors were unable to maintain continuous operation. The increasing differential pressure resulted in the TWS shear pins shearing off to protect the TWS motors. Once the TWS became stationary the continuing suction from the plant circulating water (CW) pumps resulted in further plugging of the TWS such that the only means available to maintain the Ultimate Heat Sink (UHS) level was to reduce power and secure CW pumps. UHS level was seen to increase as circulating water pumps were secured.

Once the TWS were clogged and stopped the only means to lower the differential pressure across the TWS and allow movement of the TWS was to take the plant to cold shutdown and secure all CW pumps. By securing the suction from the back side of the screen the TWS motors were able to lift the TWS clear of the water so that they could be cleaned.

It is notable that until the debris loading reached the point that the TWS differential pressure exceeded 12 inches WC the cleaning efforts were successful in removing the cladophora. However, once the debris loading reached the point where differential pressure reached 12 inches WC the TWS motors were no longer able to lift the loaded screens out of the water so that they could be cleaned.

Contributing factors to this event are high winds out the Northwest, large volumes of cladophora algae in the lake, the orientation of the submerged intake structure, the large volume of water drawn through the intake canal by three CW pumps. Preliminary evaluation results indicate that with the current design of the TWS system the only means to mitigate this environmental condition is to reduce power so that one or more CW pumps may be secured thereby reducing the rate of influx. Since these conditions can not be predicted greater than 72 hours in advance and the only effective means to mitigate the influx is to reduce power the actions taken were the correct actions.

In summary, JAF believes that the shutdown on October 13, 2007 was caused by an environmental problem that is a new phenomenon not previously experienced at JAF in terms of severity, that it could not have been predicted greater than 72 hours in advance, that interim compensatory measures put in place after the September 12, 2007 scram pending completion of the root cause evaluation were reasonable and while they did not prevent recurrence they did lessen the impact of the event in that they allowed the operations department to take prompt proactive actions to perform a unit shutdown in lieu of a scram. Based on the initial interim corrective actions and subsequent proactive measures taken by the licensee the unit shutdown should not count as an unplanned power change on the October performance indicator.

As noted above NEI 99-02 Revision 5, in discussing downpowers that are initiated in response to environmental conditions states "The circumstances of each situation are different and should be identified to the NRC in a FAQ so that a determination can be made concerning whether the power change should be counted."

Does the transient meet the conditions for the environmental exception to reporting Unplanned Power changes of greater than 20% RTP? – Yes, the transient meets the conditions for an environmental exception and should not count against the performance indicator.

Subsequent to this, the Operations Department placed guidance for lake water monitoring and actions during adverse weather conditions into Operating Procedure (OP-4), "Circulating Water System".

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

This has been reviewed with the Senior Resident and

Potentially relevant existing FAQ numbers: 158, 244, 294, 304, 306, 383, 420, 421

<u>Response Section:</u>

Proposed Resolution of FAQ:

Yes, the downpower was caused by environmental conditions, beyond the control of the licensee, which could not be predicted greater than 72 hours in advance. The licensee had taken the available measures to minimize the impact of the environmental conditions and the downpower should not count toward the performance indicator.

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

None required.

Plant: James A. FitzPatrick Nuclear Power Plant Rev. 1
Date of Event: 11/16
Submittal Date: ____________
Licensee Contact: Gene Dorman **Tel/email:** (315) 349-6810/ edorman@entergy.com
Licensee Contact: Jim Costedio **Tel/email:** (315) 349-6358/ jcosted@entergy.com
NRC Contact: Gordon Hunegs **Tel/email:** (315) 349-6667/gkh@nrc.gov

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

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

FAQ requested to become effective when approved.

Question Section:

NEI 99-02 Rev 5 Guidance needing interpretation (include page and line citation):

Unplanned Power Changes Per 7,000 Critical Hours, beginning at the bottom of page 14 at line 42 and continuing on to the top of page 15 through line 4, the guidance document states:

42 Anticipated power changes greater than 20% in response to expected environmental problems
43 (such as accumulation of marine debris, biological contaminants, or frazil icing) which are
44 proceduralized but cannot be predicted greater than 72 hours in advance may not need to be
45 counted unless they are reactive to the sudden discovery of off-normal conditions. However,
46 unique environmental conditions which have not been previously experienced and could not
47 have been anticipated and mitigated by procedure or plant modification, may not count, even if
48 they are reactive. The licensee is expected to take reasonable steps to prevent intrusion of marine
49 or other biological growth from causing power reductions. Intrusion events that can be

1 anticipated as a part of a maintenance activity or as part of a predictable cyclic behavior would
2 normally are counted unless the down power was planned 72 hours in advance. The
3 circumstances of each situation are different and should be identified to the NRC in a FAQ so
4 that a determination can be made concerning whether the power change should be counted.

Event or circumstances requiring guidance interpretation:

At FitzPatrick, intrusion of Algae (Cladophora and other types of algae vegetation) at the circulating water intake structure has occurred several times and caused Traveling Water Screen (TWS) blockage. Traveling screen blockage has lead to failure of a traveling screen. This has cascaded to multiple screen failures which can cause a loss of the Circulating Water System and loss of inlet cooling water for the plant which can cause loss of the main condenser (Ultimate Heat Sink). Because of these events, Fitzpatrick has responded by performing several down powers in order to take a circulating water pump(s) off line to reduce water velocity and thus algae adherence to the TWS.

Contributing factors to these events are high winds out of the Northwest, cladophora/algae in the lake, the orientation of the submerged intake structure, and the large volume of water drawn through the intake canal by three CW pumps.

Over the last few months, FitzPatrick has taken significant steps, including changes in operating strategy and procedures, as well as equipment enhancements to reduce vulnerability of the plant to this phenomenon. FitzPatrick has also taken steps to minimize clodophora through use of divers harvesting the algae in areas of high concentration.

This FAQ is intended to apply to the November 16, 2007 event and future downpowers related to these conditions. On 11/16/07, the Operations Department initiated a plant down power from 100%

power due to an intrusion of Cladophora Algae (CR-JAF-2007-04031). This event was similar to events that have occurred on September 12, 2007, October 13, 2007, and October 28, 2007 in that the influx of algae resulted in the operations staff lowering power (I.e., shutdown or down power) to ensure adequate inlet cooling water for the plant. Since the Root cause evaluation had not been completed for the September 12th event, all of the long term corrective actions had not been implemented for the November 16th event. However, interim corrective actions documented in Operations Shift Standing Order (OSSO) 2007-020 Revision 2 were in place at the time of the November event. Below is a complete list of actions in place as of the date of this FAQ:

Equipment Upgrades:

- Installed higher strength shear pins.
- Installed downstream screen guide rails to prevent contact with screen house floor
- Installed larger motor on screen drive train which results in higher speed operation
- Eliminated fluid coupling from the drive train
- Installed screen wash diversion troughs
- Installed larger ports in screen housings and staged fire hoses

Procedure Changes and Detection/Mitigation Strategies:

- Lowered setpoint for screen differential pressure alarm
- Added steps to OP-4 for two screen wash pump operation
- Added guidance for use of fire system sprays on screens
- Installed web cam at fish basket
- Trained operators on shear pin installation
- Staged tools, shear pins and tag out locks
- Provided additional guidance for power reduction based on weather forecast
- Set up a call-out page for intake problems

Additional Procedural Guidance Provided for Power Reduction Based on Weather Forecast:

Trigger Point # 1 from Operational Procedure:

1. **IF** severe weather, sustained winds **GREATER THAN** 20 mph, or other conditions that could cause a rise in the amount of debris in intake water, exist or are expected.

Actions if Trigger Point # 1 is exceeded:

IF Trigger 1 is exceeded **THEN** perform OP-4 Section E.2.2. This procedure section will perform the following actions:

- Place traveling screens in continuous mode per Subsection G.15 to determine amount of incoming debris.
- Frequently monitor traveling screen performance and debris basket quantity.
- **IF** significant lake debris is incoming, **THEN** continuously monitor screen performance, debris basket quantity and screen differential level.
- Commence screen wash two pump operation per Section G.29
- **IF** any indication of rising screen d/P, **THEN** perform the following:
    - Direct control room to start Fire Pump.
    - Initiate cleaning using fire hoses.

Trigger Point # 2 from Operational Procedure:

2. **IF** the following combination of wind direction and wind speed, as measured with on-site instrumentation, is met:

   Wind Direction from 240° (WSW) through 030° (NNE)

   AND

   15 minute average wind speed is greater than 30 mph

   AND

   Evidence of debris intrusion as determined by the Shift Manager using the following criteria:

   - Service Water Strainer Differential Pressure Alarms
   - Rising Traveling Screen Differential Level
   - Screenwash booster pumps with (mitigating actions of fire hose spray) are not effective in removing debris from screens. Indications of this would be an increasing amount of carry over on south side of screens.
   - Frequent fish basket change out is required **OR** if there is degradation in the methods or ability to remove incoming debris. Examples would be:
     - Malfunction of screenwell crane
     - Resources not available
     - Screen wash system degradation

Actions if Trigger Point # 2 is exceeded:

IF Trigger 2 is exceeded **THEN**

- Reduce power per OP-65 and remove C Circulating Water Pump. Power reduction at normal limit of 200 MWth/ minute is warranted.
- Contact WWM to verify Risk assessment
- Initiate "Traveling Screen Issue Report to Plant" pager message located on the Emergency Planning Department website.
- Initiate Traveling Water Screen Monitoring Plan located at M:\PLANNING\FO183\Engineering\CWS and Trav Screen Monitoring Rev 2.doc.
- Review and Brief AOP-56 (High Traveling Screen or Trash Rack Differential Level)

In summary, JAF believes that the shutdowns and down powers were caused by an environmental problem that is a new phenomenon not previously experienced in terms of severity, that it could not have been predicted greater than 72 hours in advance, that compensatory measures have been put in place. Based on the corrective actions taken and subsequent proactive measures taken by the licensee, future down powers should not count as an unplanned power change for future performance indicators.

As noted above, NEI 99-02 Revision 5, in discussing downpowers that are initiated in response to environmental conditions states "The circumstances of each situation are different and should be identified to the NRC in a FAQ so that a determination can be made concerning whether the power change should be counted."

Does the transient meet the conditions for the environmental exception to reporting Unplanned Power changes of greater than 20% RTP? – Yes, the transient meets the conditions for an environmental exception and should not count against the performance indicator.

Subsequent to this, the Operations Department placed guidance for lake water monitoring and actions during adverse weather conditions into Operating Procedure (OP-4), "Circulating Water System".

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

This has been reviewed with the Senior Resident and

Potentially relevant existing FAQ numbers: 158, 244, 294, 304, 306, 383, 420, 421

Response Section:

Proposed Resolution of FAQ:

The licensee has taken the available measures to minimize the impact of algae intrusions due to environmental conditions. Future algae intrusions are beyond control of the licensee and can not be predicted greater than 72 hours in advance. Therefore, future downpowers due to algae intrusion should not count toward the performance indicator until the TWS Modification is completed and the TWS system operates satisfactorily under similar conditions. In addition, the 11/16/07 down power should not count towards the performance indicator.

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

None required.

Plant: Byron
Date of Event: 2/1/2006
Submittal Date: 1/15/2008
Licensee Contact: Jack Feimster Tel/email: 815-406-2589 / willard.feimster@exeloncorp.com
NRC Contact: Ray Ng Tel/email: 815-406-2850 / rmn@nrc.gov

Performance Indicator: MS06 - MSPI Emergency AC Power System

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):

Appendix F, section F 5, EAC Clarifying Notes (page F-45, lines 29 and 30): An EDG is not considered to have failed due to any of the following events: spurious operation of a trip that would be bypassed in a loss of offsite power event.

Appendix F, section F 1.2.1, (page F-5, lines 14 and 15) Train unavailability: ...the hours the train was unavailable to perform its monitored functions.

Appendix F, section F.5, Emergency AC System (page F-45, line 8-10): The number of emergency AC power system trains for a unit is equal to the number of class-1E emergency generators that are available to power safe shutdown loads in the event of a loss of off-site power for that unit.

Appendix F, section F.1.1.1, Unit Cross-Tie Capability (page F-2, lines 36-41): At multiple unit sites cross ties between systems frequently exist between units. For example at a two unit site, the Unit 1 Emergency Diesel Generators may be able to be connected to the Unit 2 electrical bus through cross tie breakers. In this case the Unit 1 EAC system boundary would end at the cross tie breaker in Unit 1 that is closed to establish the cross-tie.

Event or circumstances requiring guidance interpretation:

During NRC review of MSPI data, the reviewer questioned the reporting of unavailability and failures under certain circumstances. The example in question stems from a failure of a pressure switch on the Unit 1B Emergency Diesel Generator (EDG) that resulted in a "Turbo Thrust Bearing Failure" alarm. The diesel subsequently tripped during its cool down cycle. It was determined the DG would perform its emergency function, but would not operate in test mode. The plant did not count any unavailability for this test mode failure because the DG was able to perform its emergency function.

At Byron, there are two EDGs per unit. Under MSPI, all four EDGs are monitored for each unit "due to the potential alignment of the Component Cooling Water System that may require the EDGs for the opposite unit to provide power to the CC and SX pumps." (ref. Section 2.4 of the Byron Station MSPI Basis Document.) To clarify this statement, it should be noted that the common component cooling water heat exchanger can be mechanically aligned to either unit. Depending on the alignment, one unit's component cooling water and essential service water pumps will be providing cooling to the opposite unit. The common component cooling water pump can be powered from either unit's ESF bus. Two component cooling water and two essential service water pumps are powered from each unit. Thus, in a loss of power on one unit, an opposite unit's ESF Bus may be powering a component cooling water or essential service water pump on the unit that did not lose off-site power to provide cooling to the unit that did lose offsite power. For a dual unit loss of offsite power, the opposite unit's EDG may be providing power through the ESF Bus to the component cooling water or essential service water pump to provide cooling to the opposite unit.

The NRC reviewer noted that a bus undervoltage on one unit does not provide an emergency start signal to the diesels on the other unit. The DG would need to be started manually (test mode). The reviewer questioned how an EDG with a test mode failure could supply power to the CC or SX pump that is mechanically aligned to the opposite unit, and whether this constitutes a EDG failure counted against the opposite unit. Also, should the diesel accrue unavailability for the opposite unit, and would this unavailability be unplanned?

Byron Station Response

The function of the EDG is to supply power to the ESF bus in event of a loss of off site power to that bus. Though plant design allows an EDG from one unit to be crosstied to supply power to the other unit, this function is NOT an MSPI monitored function. Only the crosstie breakers are monitored in MSPI for this function in accordance with NEI 99-02 F.1.1.1 and F.2.1.1. The opposite unit EDGs are only included in the scope of MSPI as they may be required to provide power to that unit's component cooling water and essential service water pumps following a loss of offsite power to that unit. As the MSPI function of the emergency AC power system is the ability of the emergency generators to provide AC power to the class 1E buses following a loss of off-site power, any time an EDG is performing this function, whether to support its own unit or cooling loads to the opposite unit's "A" RH Train, it is due to a loss of offsite power to the associated ESF bus. In this case, the EDG would receive an autostart signal which would not be affected by the inability to start the EDG in the test mode. Therefore, this event should not be considered a failure, nor should unavailability be accrued.

In accordance with the MSPI guidance, the MSPI scoping does not include the opposite unit EDGs for their electrical cross-tie capability. The cross-tie breakers are included in the MSPI scope and this ensures that unit electrical cross-tie capability is available under all conditions as illustrated in the following example.

> Example – Unit 1A DG has a fault that prevents it from operating correctly in test mode, although it will operate correctly in emergency mode.

Scenario 1 - A loss of offsite power (LOOP) occurs on Unit 2 only, but the 2A DG fails to start. Unit 1 can energize the ESF bus through the crosstie, as the PRA has credited. Since Unit 1 has not lost off-site power, the Unit 1 ESF bus remains energized by offsite power through the Station Auxiliary Transformer (SAT) and is capable of energizing the Unit 2 ESF bus through the crosstie.

Scenario 2- A LOOP occurs on both units and the 2A DG fails to start. The ESF bus can still be energized through the crosstie. Since Unit 1 has also lost power, the 1A DG will now be running in emergency due to the bus undervoltage on its own unit. With the diesel operating in emergency mode, any test mode fault will not be an issue. The 1A DG will be able to power the Unit 2 ESF bus through the crosstie as designed. The 1A and 1B DG have adequate capacity to supply the Unit 1 emergency loads and the required Unit 2 loads through the cross-tie.

Per NEI 99-02 guidance, an EDG is not considered to have failed due to a spurious operation of a trip that would have been bypassed in a loss of offsite power event (emergency mode). Also per NEI 99-02, unavailability is counted when the system is "unavailable to perform its monitored functions." The Byron bases document states "the function monitored for the emergency AC power system is the ability of the emergency diesel generators (EDGs) to provide AC power to the class 1E buses upon a loss of off-site power while the reactor is critical..."

Therefore, since the diesels would only be called upon to supply the opposite unit's ESF bus in emergency mode, any test mode problem that is not a failure on its own unit should be considered neither a failure nor unavailable on the other unit.

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

The NRC resident has the following position.

Per NEI 99-02 guidance, "the number of emergency AC power system trains for a unit is equal to the number of class 1E emergency generators that are available to power safe shutdown loads in the event of a loss of off-site power for that unit". For Byron station, all EDG's can supply all units. Therefore, there are four trains of diesel generators to be monitored under MSPI for each unit. Two of the diesel generators will not auto start for LOOP on the other unit.

Also, per NEI 99-02, "no credit is given for the achievement of a monitored function by an unmonitored system in determining unavailability or unreliability of the monitored systems". The ESF bus itself is not a monitored component at Byron.

The licensee's Scenario 1 credits the availability of the Unit 1 ESF bus powered by offsite power. Therefore, both Unit 1 diesel generators are not needed. The inspector stated that the availability of Unit 1 diesel generators was questionable at best since Unit 1 diesel generators could not be started unless there was an undervoltage event for Unit 1. Per the NEI guidance, credit is not given for the availability of the ESF bus.

The NEI guidance also needs to be clarified whether the unavailability of the unmonitored system (the ESF bus), which caused the opposite unit diesel generators to start, could be credited.

The licensee's Scenario 2 assumes dual unit LOOP and all four diesel generators will start due to bus undervoltage. The inspector stated that availability of opposite unit diesel generators for power was questionable at best since they were needed to deal with its own LOOP event. The NEI guidance needs to be clarified whether this is an acceptable assumption.

The NRC resident therefore believes that a test mode failure should be counted as a failure for the appropriate opposite unit MSPI train. The MSPI weighting factor would then be applied to calculate the MSPI based on site specific PRA factors.

Potentially relevant existing FAQ numbers
None

Response Section

The EDG should not be considered unavailable in this situation. The opposite unit EDGs are explicitly not considered in scope for their electrical cross tie capability. The function as stated in the basis document is to provide AC power to the class 1E buses upon a loss of off-site power. Absent a loss of off-site power, an EDG will not be required to provide power to the opposite unit via cross-tie.

Proposed Resolution of FAQ

The EDG should not be considered unavailable in this situation.

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

The guidance regarding this topic could be further clarified by inserting the following statements (inserts in bold).

Page F-44, lines 26, 26:
The function monitored for the emergency AC power system is the ability of the emergency generators to provide AC power to the class 1E buses following a loss of off-site power **to its associated unit specific class 1E bus.**

Supplemental comments:

NRC Response:

EDGs that can supply loads to both units during certain accident scenarios are still monitored by MSPI with respect to their assigned train/unit status (i.e., normally aligned unit.) For example, for a two unit site with 4 EDGs, Unit 1 will have two assigned EDGs (Unit 1 EDG-A and Unit 1 EDG-B) and Unit w will have assigned 2 EDGs Unit 2 EDG-A and Unit 2 EDG-B). The boundary that separates these 4 EDGs is the unit cross-tie breakers (see NEI 99-02, Rev 5, App F, page F-2, Unit Cross-Tie Capability).

The design basis function of Unit A EDGs supplying loads to the opposite unit is not an EAC MSPI monitored function. If this function is not met, it could, however, impact unavailability hours on other MSPI systems, such as support cooling water PI. This would need to be assessed on a plant-specific basis, as each plant design may be different. It should be noted that if the other systems are MSPI monitored systems for the other unit, then no additional unavailability would be accrued, as this would represent double counting the unavailability of the EDG.

Test-mode failure of any EDG is counted as a failure. If the license maintained the EDG in an "available" status, and where the failure rendered the EDG from auto-starting in emergency mode regardless of whether is would supply the ESF bus in either unit. However, if the emergency mode start feature was unaffected by the test mode failure, and the EDG would perform its PRA function on the assigned unit, then no failure occurred with respect to MSPI unreliability monitoring. Additionally, unavailability on the other MSPI systems would need to be evaluated with respect to how the test mode failure affected their status.

Plant:	Salem Generating Station Unit 1
Date of Event:	April 22, 2007 and April 29, 2007
Submittal Date:	November 14, 2007
Licensee Contact:	Brian Thomas Tel/email: 856-339-2022/brian.thomas@pseg.com
NRC Contact:	Dan Schroeder Tel/email: 856-935-5151/ DLS@NRC.gov

Performance Indicator: I03 – 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):

NEI 99-2 Rev. 5, Section 2.1 Initiating Events Cornerstone, Unplanned Power Changes per 7,000 Critical Hours, page 14 Lines 42 through page 15 line 4:

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

Event or circumstances requiring guidance interpretation:

During the period of April 14, 2007 and April 16, 2007, the east coast mid-Atlantic Region experienced a Nor'easter storm causing high winds and rain in the Delaware River Basin. The unusual wind direction combined with flooding conditions in New Jersey, Pennsylvania and Delaware as well as several unknown flood control dam releases up river led to excessive marine debris in the Delaware River watershed. During the two weeks following the Nor'easter storm, increased river flows were experienced, on April 21, 2007 and April 27, 2007 river flows measured at Trenton, NJ were 2 to 3 times higher than the median flow for this date range. This increased river flow tends to entrain more debris than normal at the intake structure. The grassing levels experienced in April 2007 exceeded the weekly average detritus densities experienced in 2005 (which was the previously recorded worst year ever) by approximately 33% and were the highest levels ever recorded by the station. The general make up of the debris was similar to 2005 except there was a higher concentration of trash in the 2007 debris which tends to have a greater effect on traveling screen and water box clogging.

During this period of time, Salem Generating Station was already in Action Level II of the established procedures for Grassing*. (See Attachment 1 for further discussion of the established procedure guidance). Sampling of the river for detritus was increased to a daily frequency on April 21, 2007 from the normal 3 days a week. Samples are taken continuously throughout the day to assess the immediate detritus concentration and determine the daily average and weekly average which is used in the Salem Circulating Water System Risk Snapshot. Based on the increased detritus level measurements/predictions, Operators entered the applicable procedures that directed increased inspections of the circulating water intake structure to ensure equipment is working properly. During the period of April 23, 2007 to May 3, 2007, circulating water risk snapshots (see Attachment 1 for further discussion) were increased to twice a day to set the priorities for maintenance to maintain the reliability of the circulating water system during the heavy grassing period. Although the time period during the year for grassing impact is known and procedures for monitoring grassing levels are in place, there are no accurate prediction methods that can determine the actual grassing impact at the Circulating Water intake structure greater than 72 hours in advance.

On April 20, 2007 Salem Unit 1 began its return to power from its 18th refueling outage. During the power ascension, circulating water pumps were being removed from service in accordance with procedures to clear the traveling water screens and to clean the condenser water boxes of debris. On April 22, 2007 a power level of 80% was reached. A greater than anticipated influx of marine debris/grassing occurred causing circulating water pumps to be shutdown. The delta temperatures across the condenser began to increase and power was reduced to approximately 40% power in accordance with abnormal operating procedures to maintain condenser outlet temperatures below established limits. When monitoring and predictions indicated a reduced grass level, power was increased to 48% on April 23, 2007 where it remained for approximately one day for continued monitoring of grassing levels. On April 24, 2007 grass levels increased again requiring a downpower to 40%. Late on April 24, 2007 Salem Unit 1 was manually tripped by procedure due to the tripping of several circulating water pumps as a result of an influx of marine debris/grassing. [This was counted as a reactor shutdown] (See Attachment 2 for Power-History curve)

The unit returned on April 26, 2007 while management monitored and trended the marine debris/grassing concentration levels. Salem Station was still in an elevated Action Level II condition due to elevated marine debris/grassing; however, the marine debris/grassing daily mean level began to decrease.

On April 27, 2007, Salem Unit 1 had achieved 74% power when a reduction in power to 40% was performed in accordance with procedures. An influx of marine debris/grassing led to the tripping of several circulating water pumps in accordance with procedures. The power remained at 40% until river conditions permitted return of equipment to service to allow for power ascension. The power ascension was based on actual river data parameter trend analysis of marine debris. On April 29, 2007 power was increased to 80% power. Power ascension was held at 80% for fuel conditioning requirements and would not be increased above 80% until a continued evaluation of marine debris/grassing levels occurred. On April 30, 2007 river marine debris/grassing levels unexpectedly increased. The onset of the volume of marine debris/grassing was not within the predicted, monitored and trended parameters of the river. The condition required tripping of four of six circulating water pumps and the reactor was tripped in accordance with the abnormal operating procedures. [This was counted as a reactor shutdown] The marine debris was only visible by screen loading at the time of the event.

The station has taken numerous reasonable steps to increase unit reliability over the past years by modifications to improve the circulating water intake performance, which has proved successful in coping with record marine debris/grassing season in 2005. The station has recently implemented and tested a new traveling water traveling screen.

In addition, following the April 2007 down powers and unit trips a root cause evaluation was performed with a corrective action to determine if any further actions could be done to minimize the impact of grassing on the Unit operation. This action has determined that throttling of the circulating water flow to reduce the impingement of grass on the circulating water traveling screens may help prevent future plant trips; however, these actions would not avoid the unanticipated down powers. Additional river grassing predictions were reassessed during the root cause evaluation but no actions were identified that would be able to reliably predict increased grassing levels 72 hours in advance.

Given that the circumstances of this marine debris intrusion were beyond the control of the plant, and that appropriate site actions are proceduralized, can the April 22, 2007 and April 27, 2007 down power events be exempted from counting as an unplanned power change? Based on the information provided, it is recommended that the April 22, 2007 and April 27, 2007 down powers not be counted since the magnitude of the onset of marine debris could not have been predicted 72 hours in advance.

*Note: The term "grassing" or "grass" as used in this FAQ is marine debris that is in the form of reeds (Phragmites), detritus (decaying organic matter from marsh bottoms), hydroids, leaves, and trash.

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

Potentially relevant existing FAQ numbers
420 Oyster Creek, 421 Calvert Cliffs, 409 Fitzpatrick, 383, 389

Response Section (Proposed)
The down powers that are described in this FAQ do not count. The facility has developed specific procedures to proactively monitor environmental conditions that would lead to marine debris intrusion and directs proactive actions to take before the intrusion and actions to take to mitigate the actual intrusion. (e.g. – critical maintenance performed prior to grassing season, staffing levels to support traveling screen and condenser waterbox cleaning during grassing season, risk assessment for setting maintenance/monitoring priorities to ensure reliability of the circulating water system)

Proposed Resolution of FAQ

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

Attachment 1

Grassing Awareness/Preparation/Monitoring/Trending/ Action/Prediction

Grassing Season Awareness and Preparation

The Site has a proceduralized Station Seasonal Readiness Guide. The purpose of the procedure describes the process for preparing Salem Units 1&2 for reliable operation during the summer, winter and periods of high marine debris/grass flow in the Delaware River. The procedure contains a timeline for Grassing Seasonal Readiness. The Grassing Season is defined as the period from February 1st through May 15th. The procedure directs formal system material condition reviews for the identification and scheduling of grassing readiness deficiencies. Reviews are performed for the circulating water trash rakes, pumps, motors, waterboxes, traveling screens screen wash pumps and other equipment to assess readiness for grassing season. This review also assesses the necessary spare components for grassing season. Grassing readiness mandatory items are scheduled to be completed by February 1st.

Grassing Season Monitoring and Actions

River conditions are routinely monitored as described in the River Conditions Update procedure (NC.LR-DG.ZZ-0015). When the instantaneous detritus weight exceeds a certain limit or the rolling weekly average exceeds certain levels, the sample collector must notify Salem Operations of elevated grass levels. Upon receiving this notification, the Operators evaluate entry into either SC.OP-SO.ZZ-0003, "Component Biofouling," or SC.OP-AB.ZZ-0003, "Component Biofouling." These procedures provide guidance to determine the Action Level the station enters based on observed river debris content, screen carryover, measurement of marine debris (detritus loading), fouling indication of a river supplied heat exchangers or number of traveling water screens in high speed.

The seasonal readiness guide directs that the proper resources are in place from the Operations, Maintenance and Engineering Organizations to support the grassing season. These resources are assigned during the grassing season to support walk downs of the circulating water structure, determine the priority of emergent work affecting the circulating water system, cleaning of traveling water screens and condenser water boxes and performance of maintenance to maintain reliability of the circulating water system. The seasonal readiness guide provides a walk down list to perform during the grassing season. This walk down list provides which components to inspect during the shiftly walk downs and the criteria for maintaining the reliability of the components.

Grassing Level Trending and Analysis (Prediction)

The seasonal readiness procedure also provides guidance on determining the Salem Circulating Water System risk snapshot. This risk snapshot takes into account those factors that can influence the influx of grassing into the intake structure including the tide changes (whether they are above or below normal levels), wind direction and speed (is the wind blowing towards the intake structure), temperature and actual or predicated rain fall. These factors then determine if increased river monitoring for grass levels is necessary. The risk snapshot then takes into account the detritus level and status of circulating water system components to determine an overall risk color of either green, yellow or red. Green meaning no risk with monitoring to ensure stable conditions, yellow meaning a potential risk with heightened awareness and some actions, or red meaning at risk and that action is required to restore defense in depth. The circulating water risk assessment then sets the priority for maintenance on the circulating water system components to maintain the reliability of the system during the heavy grassing periods.

Plant: Diablo Canyon Power Plant
Date of Event: 01/05/2008
Submittal Date: 02/08/2008
Licensee Contact: Steven Hamilton **Tel/email:** (805) 545-3449/swh2@pge.com
NRC Contact: Michael Peck **Tel/email:** (805) 595-2354/msp@nrc.gov

Performance Indicator: Unplanned Power Changes per 7,000 Critical Hours (IE03)

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

FAQ requested to become effective upon approval.

Question Section:

Unplanned Power Changes Per 7,000 Critical Hours, beginning at the bottom of page 14 at line:

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

Event or circumstance requiring guidance interpretation:

During the winter storm cycle, each storm event is evaluated by Diablo Canyon Power Plant (DCPP) staff for its potential impact on power operations. Based on plant policy and procedures, anticipatory power reductions are imposed where marine and/or biological intrusion is predicted at levels that could result in the need to secure a circulating water pump to protect plant systems, such as the intake traveling screens, from damage. However storm predictions may not result in a decision to initiate a unit power reduction in advance of the storm peak. Based on the uncertainty regarding the magnitude of expected marine/biological intrusion, plant procedures also call for the monitoring and trending of main condenser differential pressure. If a maximum threshold is reached, plant procedures direct a power reduction to address the marine/biological intrusion.

On January 05, 2008, DCPP Unit 1 conducted a planned and controlled power reduction of greater than 20 percent in response to storm-induced marine/biological intrusion into the main condenser water boxes. In anticipation of the storm's potential impact on plant operation, an Operational Decision-making Meeting was conducted to evaluate the predicted magnitude of the storm and its potential impact on plant equipment. The conclusion reached in this meeting was that the predicted magnitude of the storm, combined with the available marine/biological debris, was not sufficient to challenge the structural integrity or debris mitigation capability of the traveling screens. As a result, an anticipatory reduction in power was not initiated. As the storm progressed, its magnitude intensified, exceeding the predicted peak level. The resulting carryover of marine/biological debris caused the main condenser differential pressure to ramp up.

As directed by plant procedures, operators initiated a controlled power reduction (to 55%) when main condenser differential pressure exceeded the prescribed value.

PG&E takes all reasonable actions to assess the effect of Pacific storms on DCPP and takes appropriate actions to both protect plant equipment and to minimize the impact on plant operation. In addition, intake bar racks, seawater traveling screens, circulating water pumps, and main condensers are properly maintained to ensure this important equipment functions as designed under all conditions. Thus, the reporting of power reductions as a result of storm-induced marine/biological debris intrusion – both anticipatory and in response to monitored parameters – satisfies the exclusion for reporting under PI IE03 "Unplanned Power Changes per 7000 Critical Hours."

Potentially relevant existing FAQ numbers: 421, 433

Response Section

For Diablo Canyon Power Plant, where storm events and their impact on power operation is closely monitored by plant procedures, the need for power reduction of greater than 20 percent to protect plant equipment in response to marine/biological intrusion that cannot be predicted greater than 72 hours in advance will be exempt from NRC PI IE03 reporting.

The Diablo Canyon NRC SRI agrees that this issue is proper for submittal to the NRC PI FAQ process

Plant: H. B. Robinson Steam Electric Plant, Unit No. 2
Date of Event: 6/30/2007 **Performance**
Submittal Date: 2/19/2008 **Licensee Contact:** Ashley Valone Tel/email: (843) 857-1256
NRC Contact: Robert Hagar Tel/email: (843) 857-1301 bob.hagar@pgnmail.com

Indicator: Initiating Events – Unplanned Power Changes per 7000 Critical Hours

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

Yes, FAQ requested to become effective when approved.

Question Section

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

NEI 99-02, Revision 5, Pages 14 and 15:

42 Anticipated power changes greater than 20% in response to expected environmental problems 43 (such as accumulation of marine debris, biological contaminants, or frazil icing) which are 44 proceduralized but cannot be predicted greater than 72 hours in advance may not need to be 45 counted unless they are reactive to the sudden discovery of off-normal conditions. However, 46 unique environmental conditions which have not been previously experienced and could not 47 have been anticipated and mitigated by procedure or plant modification, may not count, even if 48 they are reactive. The licensee is expected to take reasonable steps to prevent intrusion of marine 49 or other biological growth from causing power reductions. Intrusion events that can be

1 anticipated as a part of a maintenance activity or as part of a predictable cyclic behavior would 2 normally be counted unless the down power was planned 72 hours in advance. The 3 circumstances of each situation are different and should be identified to the NRC in a FAQ so 4 that a determination can be made concerning whether the power change should be counted.

Event or circumstances requiring guidance interpretation:
On June 30, 2007 during a heavy rain and lightning storm the 'A' Heater Drain Pump (HDP) unexpectedly tripped due to a failure of the associated 4 kV power feeder cables. Power was reduced to less than 50% power. Based on an engineering evaluation, it was determined that a lightning strike caused an over-voltage condition that damaged the insulation on the 'A' HDP supply feeder cables resulting in an over-current fault, which tripped the HDP.

A review of plant records did not identify previous weather-related failures of the 4 kV feeder cables. Therefore, a failure of the associated 4 kV feeder cables due to a lightning strike, and consequent failure of the HDP, is considered unanticipated and is not mitigated by plant procedures or modifications.

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

The NRC Resident agrees with the facts of the FAQ.

FAQ 79.1

Plant: Generic
Date of Event: February 28, 2008
Submittal Date: March 19, 2008
Contact: Julie Keys Tel/email 202-739-8128, jyk@nei.org
NRC Contact: Nathan Sanfilppio Tel/email: 301-415-3951

Performance Indicator: PP02 & PP03

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):
At various places throughout the guidance, NEI 99-02 discusses Performance Indicators PP02 & PP03 including:

Page 8, Table 1
Page 71
Pages 79 - 82

Event or circumstances requiring guidance interpretation:
On February 28, 2008, NRC issued RIS 2008-04 to inform licensees that the "Personnel Screening Program" and the "Fitness-for-Duty/Personnel Reliability" performance indicators used in the Security section of NEI 99-02 will be discontinued. These PIs were discontinued because the aspects of security programs measured by the PIs are assessed by the security baseline inspection program and that this redundancy challenged efficiency and caused undue regulatory burden. In addition, the data gained and insights provided by these PIs have been of limited additional value to the security ROP and are already reported to the NRC through 10CFR reporting requirements.

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

Potentially relevant existing FAQ numbers
N/A.

Response Section

Proposed Resolution of FAQ

If appropriate, provide proposed rewording of guidance for inclusion in next revision.
Delete all references to PP02 and PP03 in NEI 99-02.

FAQ 79.2

Plant: Brown Ferry Nuclear Power Plant
Date of Event: 01/03/08
Submittal Date:
Licensee Contact: James Emens **Tel/email:** (256) 729-7658/ jeemens@tva.gov
Licensee Contact: Steve Armstrong **Tel/email:** (256) 729-3672/ slarmstrong@tva.gov
NRC Contact: Thierry Ross **Tel/email:** (256) 729-2573/ TMR@nrc.gov

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

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

FAQ requested to become effective when approved.

Question Section:

NEI 99-02 Rev 5 Guidance needing interpretation (include page and line citation):

Unplanned Power Changes per 7,000 Critical Hours, beginning at the bottom of page 14 at line 42 and continuing on to the top of page 15 through line 4, the guidance document states:

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

Event or circumstances requiring guidance interpretation:

On 1/03/08, Operators at the Browns Ferry Nuclear Plant received "TRAVELING SCREEN DP HIGH" alarms and lowering condenser vacuum on all three units. In accordance with plant procedure 2-GOI-200-12, Power Maneuvering, Unit 2 lowered reactor power to approximately 50% to maintain condenser vacuum above the turbine trip set point. The unit returned to 100% power on 01/04/08, 7:13 AM. This condition resulted from shad being pulled into the traveling water screens and blocking water flow. On 1/06/08, 10:00AM, BFN Unit 2 commenced power reduction to 65% for water box cleanings necessitated by the shad run on 1/03/08. The unit returned to 100% power on 01/07/08, 2:36 AM.

After the power reduction, BFN conducted a review of the event. During this review, it was found that on or before 1/3/08, a large number of Threadfin shad experienced thermal shock and were drawn into the BFN intake structure causing clogging and damage of the traveling water screens. This reduced the Condenser Circulating Water (CCW) flow and resulted in an unplanned power reduction.

It is known that Threadfin shad may experience shock when there is a water temperature change of greater than 2 degrees F in a 24-hour period or when water temperature falls below 45.5°F. For this BFN event, the fish stun actually began during the morning hours on 1/2/08 when river temperature fell to 45.5°F (~0300 Central Standard Time when intake temp hit 45.5). Shortly thereafter, the temperature reached the greater than 2°F change in 24 hours.

The exact cause for the thermal shock cannot be determined. TVA River Operations had significantly varied river water flows for several days prior to the event to support meeting peak power demands. A rapid increase in river flow could result in a temperature drop sufficient to result in thermal shock. However, the thermal shock could have occurred naturally. Unusually cold weather or strong winds coupled with cold weather can cause the water temperature to fall to 45.5°F or to be cooled 2°F in 24 hours. These conditions did exist prior to the event.

Another factor was the low amount of rainfall in the previous year which resulted in lower reservoir levels and lower river flows. These factors established conditions where an increase in river flow could result in a more extreme temperature differential. The drought conditions in the area have been more severe this past year than any time previous in Brown Ferry's operational experience.

There is little to no ability to predict these shad stuns. Corrective actions focus on better communication with River Operations and understanding of planned changes to river flows and better preparations when weather conditions may be suitable for a natural temperature drop to or below 45.5 F.

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

This has been reviewed with the Senior Resident and there is no disagreement on the facts and circumstances of this event.

Potentially relevant existing FAQ numbers: 158, 244, 294, 304, 306, 383, 420, 421

Response Section:

Proposed Resolution of FAQ:

There is little to no ability to predict these shad stuns other than observing temperatures to anticipate approach to the 45.5 F level. Corrective actions will focus on better communication with River Operations and understanding planned changes to river flows and better preparations when weather conditions may be suitable for a natural temperature drop to or below 45.5 F. However, these actions will only better prepare BFN to mitigate the consequences and not to prevent the event.

BFN is requesting that this specific event be classified as an environmentally caused down power and not count as an unplanned power reduction for the purpose of this Performance Indicator. This request is specific to this event and is not seeking to establish precedent.

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

None required

FAQ 79.3

Plant: Brown Ferry Nuclear Power Plant
Date of Event: Historical (8/16/07, 8/22/07, 8/23/07, 11/25/07)
Submittal Date:
Licensee Contact: James Emens **Tel/email:** (256) 729-7658/jeemens@tva.gov
Licensee Contact: Steve Armstrong **Tel/email:** (256) 729-3672/ slarmstrong@tva.gov
NRC Contact: Thierry Ross **Tel/email:** (256) 729-2573/ TMR@nrc.gov

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

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

FAQ requested to become effective when approved.

Question Section:

NEI 99-02 Rev 5 Guidance needing interpretation (include page and line citation):

Unplanned Power Changes per 7,000 Critical Hours, beginning at the bottom of page 14 at line 42 and continuing on to the top of page 15 through line 4, the guidance document states:

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

Event or circumstances requiring guidance interpretation:

During a review of the NRC Performance Indicator for unplanned power changes (> 20%), by the BFN NRC resident, it was discovered that BFN had not submitted an FAQ for power changes greater than 20% caused by environmental conditions and National Pollutant Discharge Elimination System (NPDES) restrictions for plant thermal discharge to the Tennessee River. BFN reviewed each environmental down power against reporting criteria and received input and concurrence from corporate on the reporting of generation losses due to environmental conditions. However, BFN did not submit an FAQ for each occurrence.

There are several sets of rules for performance indicator reporting - NRC, WANO and NERC GADS. In discussion with the data collector and the independent verifier, it was discovered that these individuals did not use all applicable guidance resulting in a misinterpretation regarding the need to submit a FAQ for these types of events as required by NEI 99-02. This issue is documented in the BFN corrective action program. Corrective actions are to submit this FAQ for previous environmental down powers and to require the preparers and reviewers to re-read the reporting requirement in NEI 99-02.

BFN reviewed historical generation data from 2003 to the present and found the following seven (7) occurrences where a down power of greater than 20% was classified as environmental. All the events occurred in 2007. These events had all been identified as unplanned power changes greater than 20%, were not included in the information reported to the NRC, and did not have an FAQ submitted because of a misunderstanding of the reporting requirements.

Unit 1

REGULATORY THERMAL COMPLIANCE - On 8/16/07 at 14:53, BFN Unit 1 commenced power reduction from 85% to approximately 74% due to downstream river temperature. The unit returned to 100% on 8/17/07 at 11:38 AM.

REGULATORY THERMAL COMPLIANCE - On 8/22/07 at 8:40 AM, BFN Unit 1 commenced lowering Reactor Power with Recirc Flow IAW 1-GOI-100-12, RCP, 1-OI-68 and RE recommendation. Power was lowered to 75% due to downstream river temperature. The unit returned to 100% power on 8/23/07 at 2:47 PM. On 8/23/07 at 6:58 PM Ops held pre-job brief and Reactivity Control brief in preparation for lowering power from 100% to 75% due to down stream river temperature; at 11:00PM started lowering power from 75% to 50%. Return to 100% on 8/26/07 at 17:05.

Unit 2

REGULATORY THERMAL COMPLIANCE - On 8/16/07 at 2:45 AM, Operations began lowering BFN Unit 2 power from 85% due to down steam river temperature. The unit was shut down at 5:40 PM. The unit was restarted on 8/20/07 at 2:45 PM and returned to 85 percent power on 8/22/07 at 5:00 AM.

REGULATORY THERMAL COMPLIANCE - On 8/22/07 at 9:43 AM, Operations held pre-job brief and started BFN Unit 2 power reduction to 75% with recirc flow per 2-OI-68 section 6.2, 0-GOI-100-12 (Power Maneuvering) and 0-TI-464 (Reactivity Control Plan #U2 070810-000). On 8/23/07 at 10:41 PM, power was further reduced to 50% to control downstream river temperature. Power was raised to 75% on 8/26/07 at 8:45. The unit returned to 95% on 8/27/07 at 3:18 AM.

REGULATORY THERMAL COMPLIANCE - On 11/25/07 at 8:36 PM, Operations held pre job brief in preparation for lowering BFN Unit 2 power to 75% due to river temperature per 2-GOI-200-12 Power Maneuvering. The unit returned to full power on 11/26/07 at 11:00 AM.

Unit 3

REGULATORY THERMAL COMPLIANCE - On 8/16/07 at 2:35 AM, Operations began lowering BFN Unit 3 power from 100% to 85% due to down stream river temperature. On 8/16/07 at 1430, following discussions with RSO and Operations Management, power was reduced 10% in order to lower downstream river temperature. Returned to 95%, 8/18/07 at 00:40. The Unit returned to 100% power on 8/20/07 at 01:45.

REGULATORY THERMAL COMPLIANCE - On 8/23/07 at 8:32 PM, Ops began lowering BFN Unit 3 power from 100% to 75% due to high down steam river temperature. The unit was returned to100% power on 8/27/07 at 11:55 PM.

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

This has been reviewed with the Senior Resident and there is no disagreement with the facts associated with these events and that these events were the consequence of unpredictable environmental conditions.

Potentially relevant existing FAQ numbers: 158, 244, 294, 304, 306, 383, 420, 421

Response Section:

Proposed Resolution of FAQ:

These down powers were made to ensure compliance with BFN's environmental permit. BFN utilizes mechanical draft cooling towers to cool the condenser circulating water prior to discharge to the Tennessee River, however, during periods of extreme heat and/or low rainfall, the cooling towers are not adequate for keeping the units at full power and in compliance with environmental restrictions. On these isolated occasions, BFN has responded by reducing power to ensure compliance. Because of the many variables involved such as water temperature, air temperature, river flow, rainfall, etc. it is not always possible to predict the need to reduce power 72 hours in advance.

These seven events occurred in 2007, which was one of the driest years on record for the Tennessee Valley. The low amount of rainfall resulted in lower reservoir levels and lower river flows. These events are similar to the plant specific example contained in NEI 99-02 Appendix D for Quad Cities.

BFN is requesting that these specific events be classified as environmentally caused down powers and not count as unplanned power reductions for the purpose of this Performance Indicator. BFN has taken action to ensure future down powers resulting from environmental conditions are appropriately documented in FAQs.

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

None required

ENCLOSURE 10

FAQ 75.2

The Unplanned Power Changes PI addresses changes in reactor power that are not an expected part of a planned evolution or test. In this case, since the unexpected portion of the unplanned power change was not more than approximately 10% of full reactor power, it does not count toward the Unplanned Power Change PI.

FAQ 76.3

The EDG should not be considered unavailable in this situation.

EDGs that can supply loads to both units during certain accident scenarios are still monitored by MSPI with respect to their assigned train/unit status (i.e., normally aligned unit.) For example, for a two unit site with 4 EDGs, Unit 1 will have two assigned EDGs (Unit 1 EDG-A and Unit 1 EDG-B) and Unit 2 will have assigned 2 EDGs (Unit 2 EDG-A, Unit 2 EDG-B). The boundary that separates these 4 EDGs is the unit cross-tie breakers (see NEI 99-02, Rev 5, App F, page F-2, Unit Cross-Tie Capability).

The design basis function of Unit A EDGs supplying loads to the opposite unit, is not an EAC MSPI monitored function. If this function is not met, it could, however, impact unavailability hours on other MSPI systems, such as the support cooling water PI. This would need to be assessed on a plant-specific basis, as each plant design may be different.

Test-mode failures of any EDG is counted as a failure, IF the licensee maintained the EDG in an "available" status, and where the failure rendered the EDG from auto-starting in emergency mode regardless of whether it would supply the ESF bus in either unit. However, if the emergency mode start feature was unaffected by the test mode failure, and the EDG would perform its PRA monitored function on the assigned unit, then no failure occurred with respect to MSPI unreliability monitoring. Additionally, unavailability on the other MSPI systems would need to be evaluated with respect to how the test mode failure affected their status.

FAQ 76.4

Any change to the MSPI Consolidated Data Entry (CDE) coefficients, which includes changes resulting from PRA updates, discovered CDE input errors, and PRA modeling revisions, will not take effect in the quarter that they are made. This understanding is consistent with NEI 99-02, Section 2.2 that emphasizes any PRA model changes that impact MSPI input values (CDE coefficients) will take effect the following quarter in which they are made. It should be noted that it is impractical to list every possible way that CDE input values can change. Changing from Option 1 to Option 2 on calculation of the [FV/UR] Max used by the MSPI algorithm is a change in the PRA input in the calculation of the CDE input values. Therefore, it is considered a change in use of PRA values used by CDE and the change can only take effect in the next quarter.

This position is also consistent with FAQ 432 which stated that for changes to PRA coefficients will be used in the MPSI calculation the quarter following the approved PRA update; and that changes to non-PRA information will become effective in the quarter following an approved revision to the site MSPI basis document.

REACTOR OVERSIGHT PROCESS
ROP Working Group Action List – Status March 2008

Action Item	Description	Task	Responsible Org/Individual	Target Date
MSPI-05	**Maintenance –Induced PMT issues** Revise the guidance for maintenance-induced damage/issues found during PMP prior to returning the component to function status.	Derived from survey comments.	Jim Peschel	**NRC**
	Status: 03/08 Provided to NRC			
MSPI-06	**Guidance Clarifications** Evaluate the need to clarify the guidance for: Reporting of operational run hours that are a continuation of a PMT run 1)	Derived from the results of the survey comments.	ROPTF	**NRC**
	Status: 03/08 Provide to NRC.			
MSPI-08	**CDE Improvements** Develop a prioritized schedule for following CDE improvements. Seek additional funding from the industry if necessary.	Derived from the survey comments. Simple software change to be completed near-term. Need NRC concurrence.	ROPTF	**Mar 2008**
	Status: Ask NRC to allow changes to parameters during the quarter.			
MSPI-01	**Unavailability**			
	Consider revising the treatment of baseline unavailability to account for the risk work of planned unavailability and simplify management of unavailability data.	This recommendation is derived from the recognition that the current design does not fully reflect the risk impact of planned	**NEI ROPTF**	**NRC**

ENCLOSURE 11

Action Item	Description	Task	Responsible Org/Individual	Target Date
		unavailability, from variations identified in the actual risk contributions of planned unavailability during the data review, and from the survey comments regarding the need to simplify this process		
	Status: Waiting on NRC research project but we decided to draft our proposal and provide to NRC in Feb for input.			
MSPI-02	**Simplify Indicator**			
MSPI-02c	Simplify reporting of demands and run hours. This includes consolidating demand types (ESP non test, non test and test), making it less cumbersome to validate the 25% requirement to revise estimates, discouraging counting of actual demands, and considering allowing PMT demands to count for simplification of data collection. **03/08: Give to NRC**			
MSPI-03	**Time of discovery** Resolve the current issue with regard to "time of discovery" as it relates to failures. (fault exposure)	There were 2 FAQs on this and is also derived from survey comments.	ROPTF	**Mar 2008**
	Status: Draft to NRC in January. Prepared definition and we provided it to NRC in January. Ask NRC status at Feb meeting. ROPTF to prepare revision for March. 03/08 Provide rev to NRC.			
MSPI-04	**EDG Run Failures** Revise the guidance to resolve the excessive impact of EDG run failures.	Derived from the results of the data review	ROPTF	**April 2008**
	Status: Gave white paper to NRC in Jan. 2008. Check impact on plant and let discuss in Feb. Ask NRC status in Feb. 02/08 Waiting NRC comments. 03/08: TF to research and provide input to NRC in April.			
08-01	**MC 0612** Provide markup and examples to improve the greater then minor guidance.	Our action closed. Track NRC action.	ROPTF	**NRC**
	Status: Provided to NRC in January 2008. Track their update of 0612.			
08-02	**Environmental Conditions**			

Action Item	Description	Task	Responsible Org/Individual	Target Date
	Draft white paper on changing environmental conditions		ROPTF	**Mar 2008**
	Status: Draft provided in January. Needs more discussion. Update in Feb and discuss again. 03/08 Get NRC update.			
08-03	**Risk Cap Issues** Draft white paper on fix to avoid plant's "falling off a cliff" (going from green to yellow) due to a risk cap.		ROPTF	**April 2008**
	Status: Group to discuss if this is a fix we should pursue.			
09-01	**Plant Startups after prolonged Shutdown** Draft white paper to address the BFN issue and clarify the guidance.	White paper should address how plants that have been shutdown for awhile (we will have to define some period or other criteria) transition back into PIs.	ROPTF	**TBD**
	Status:			