HANDOUT #5 FAQ LOG

TempNo.	PI	Topic	Status	Plant/ Co.
75.0	IE01	Manual Shutdown to Repair Valve	12/05 Introduced and discussed 1/16 Discussed 2/20 Discussed	Perry
75.1	IE01 IE03	Power Runback due to Recirc pump motor fault and subsequent Manual Shutdown	12/05 Introduced and discussed 1/16 Discussed 2/20 Discussed	Perry
75.2	IE01	Appx 5% Unplanned Power change during Shutdown to Repair valve	12/05 Introduced and discussed 1/16 Discussed 2/20 Discussed	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 Discussed	Byron
76.4	MS06	Basis Document Change	1/16 Introduced and 2/20 Discussed	Salem
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
78.2	MS06	EDG Non-Monitored Component Failure	2/20 Introduced and discussed	Vermont Yankee

ENCLOSURE 7

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-1 Unplanned Scrams

Site-Specific FAQ (Appendix D)? No

FAQ requested to become effective when approved.

Question Section

NEI 99-02 Guidance needing interpretation (include page and line citation):
The definition of an unplanned scram is on NEI 99-02, Rev 4, Page 10, lines 11 through 14, and includes the following statement: "Unplanned scram means that the scram was not an intentional part of a planned evolution or test as directed by a normal operating or test procedure."

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, Operations performed an "A" and "B" Reactor Recirculation Pump downshift. The resulting downpower is the subject of another FAQ.

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 the shutdown was planned and was completed in accordance with normal plant procedures.

The shutdown was not counted as an Unplanned Scram due to the following guidance from NEI 99-02, Revision 4.

> Page 9, line 21, states that the indicator monitors unplanned scrams.
>
> Page 10, lines 11 through 14, define an unplanned scram as a scram that was not an intentional part of a planned evolution or test as directed by a normal operating or test procedure. This scram was intentional, planned, and was directed by a normal operating procedure.

Page 10, lines 36 through 45, provides examples of types of scrams that are included. This scram does not fit any of those examples.

Page 11 provides examples of scrams that are not included. Lines 4 and 5 exclude scrams that are part of a normal planned operation or evolution. This scram meets that criterion. Lines 10 and 11 exclude scrams that occur as part of the normal sequence of a planned shutdown. FENOC believes that his scram meets that criterion.

In addition SECY 99-07A states "The objective of the Initiating Events cornerstone is to limit the frequency of those events that upset plant stability and challenge critical safety functions. Such an event can lead to either an automatic scram when a plant parameter exceeds a set point, or a manual scram when directed by an abnormal procedure or an emergency operating procedure. In addition, operators are trained to manually scram the reactor if an automatic scram is unavoidable. A manual scram, therefore, may be implemented for the same or similar plant conditions that would cause an automatic scram, and the effect on the plant is the same - to upset plant stability and challenge critical safety functions." This indicates that the purpose (objective) of this PI is to count those events that either resulted in an automatic scram or resulted in the need to manually scram the reactor with some immediacy (with no preplan). This scram was pre-planned and was conducted in accordance with the normal shutdown procedure; it was not taken as a reaction to plant conditions that were, or were believed to be, precursors to an automatic scram and was not directed by an abnormal or emergency operating procedure. Therefore, FENOC believes that this shutdown does not represent an Unplanned Scram.

Should this scram be counted as an unplanned scram and reported under IE-01

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

The licensee and the NRC senior resident inspector agree on the facts described in this FAQ. However, the NRC senior resident inspector believes that the circumstances of the event were not representative of a scram that was an intentional part of a planned evolution as directed by a normal operating procedure. Some elements of the event that the senior resident inspector considered included: 1) the scram was not conducted using procedure Integrated Operating Instruction (IOI) IOI-4, "Shutdown." It was conducted from a higher reactor power level using IOI-8, "Shutdown by Manual Scram," which directed operators to follow Off-Normal Instruction ONI-C71-1, "Reactor Scram;"[1] 2) the scram was not consistent with the approved reactivity plan; and 3) the off-

[1] Footnote added to clarify procedural usage - IOI-4 is the soft shutdown procedure. The procedure that is normally used to shutdown the plant is IOI-8, which is used for planned scrams – such as leading into a refueling outage when a soft shutdown is not used. ONI-C71-1 is entered following a scram – whether initiated by off-normal instructions, plant emergency instructions or IOI-8.

normal plant configuration (single loop) and shutdown conditions were a result of an unintentional loss of a recirculation pump that occurred about 2.5 hours prior to the unplanned scram.

Potentially relevant existing FAQ numbers

The NRC resident inspector believes FAQ 5 is potentially relevant. FAQ 5 addresses a plant that was in an LCO requiring the plant to be in Mode 2 within 7 hours. The plant used a standing operational procedure to assure that the LCO was met, and executed a manual scram in accordance with that procedure. This scram was considered not to count since the plant shutdown to comply with the Technical Specification LCO was conducted in accordance with the normal plant shutdown procedure, which includes a manual scram to complete the shutdown. The FAQ response also states that if the actions to meet the Technical Specification LCO required a manual scram outside of the normal plant shutdown procedure, then the scram would be counted as an unplanned scram. FENOC does not believe that FAQ 5 is relevant because Perry was not in an LCO requiring a shutdown at the time of the scram. However, FENOC believes that the principle espoused by this FAQ is that manual scrams conducted in accordance with the normal plant shutdown procedure do not count and manual scrams that are not conducted in accordance with the normal plant shutdown procedure do count. The June 22, 2007 scram was conducted in accordance with the normal plant shutdown procedure.

The NRC resident inspector believes FAQ 275 is potentially relevant. FAQ 275 addresses a plant that is reducing power for a planned refueling outage, and is planning to insert a manual scram at 25 percent power in accordance with the plant shutdown procedure. At 28 percent power, as a result of a report from the field, operators believe they are about to have an equipment failure that would lead to an automatic scram. The operators immediately inserted a manual scram. FENOC does not believe FAQ 275 is relevant because, unlike the Perry shutdown, in the FAQ the plant was scrammed because the operators believed that they were about to have an equipment failure that would lead to an automatic scram. Therefore, the scram in FAQ was not in accordance with the normal plant shutdown procedure. This FAQ reiterates the principle that scrams count for this PI when the normal shutdown procedure is not used.

Response Section

Proposed Resolution of FAQ

The plant was shutdown via a planned manual scram in accordance with normal operating procedures and does not count as an Unplanned Scram for the purposes of the performance indicator.

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

No revision to the guidance is required.

Plant: Perry
Date of Event: June 29, 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-1, Unplanned Scrams
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):
The definition of an unplanned scram is on NEI 99-02, Rev 4, Page 10, lines 11 through 14, and includes the following statement: "Unplanned scram means that the scram was not an intentional part of a planned evolution or test as directed by a normal operating or test procedure."

Event or circumstances requiring guidance interpretation:
On June 27, 2007, while operating at 86% reactor power, a reactor recirculation pump motor experienced a fault. As a result, the plant experienced a power runback to 55% reactor power. This was counted as an Unplanned Power Change.

The decision was made to shutdown the reactor by a manual reactor scram in accordance with the normal shutdown procedure. An outage schedule was developed that included the decision to scram the plant, this decision was communicated to plant employees, and the operating crew that would be scramming the plant practiced the scram on the simulator.

On June 29, 2007, in order to repair the pump motor fault, Operations entered their normal shutdown procedure, IOI-8, and shutdown the plant by manually inserting a scram in accordance with that procedure. This procedure is intended to be used during a non-emergency condition with plant conditions stable. The shutdown was originally not counted as either an Unplanned Scram or an Unplanned Power Change, but will be counted as an Unplanned Power Change.

The shutdown was not counted as an Unplanned Scram due to the following guidance from NEI 99-02, Revision 4.

Page 9, line 21, states that the indicator monitors unplanned scrams.

Page 10, lines 11 through 14, define an unplanned scram as a scram that was not an intentional part of a planned evolution or test as directed by a normal operating or test procedure. This scram was intentional, planned, and was directed by a normal operating procedure.

Page 10, lines 36 through 45, provides examples of types of scrams that are included. This scram does not fit any of those examples.

Page 11 provides examples of scrams that are not included. Lines 4 and 5 exclude scrams that are part of a normal planned operation or evolution. This scram meets that criterion. Lines 10 and 11 exclude scrams that occur as part of the normal sequence of a planned shutdown. This scram meets that criterion.

In addition SECY 99-07A states "The objective of the Initiating Events cornerstone is to limit the frequency of those events that upset plant stability and challenge critical safety functions. Such an event can lead to either an automatic scram when a plant parameter exceeds a set point, or a manual scram when directed by an abnormal procedure or an emergency operating procedure. In addition, operators are trained to manually scram the reactor if an automatic scram is unavoidable. A manual scram, therefore, may be implemented for the same or similar plant conditions that would cause an automatic scram, and the effect on the plant is the same - to upset plant stability and challenge critical safety functions." This indicates that the purpose (objective) of this PI is to count those events that either resulted in an automatic scram or resulted in the need to manually scram the reactor with some immediacy (with no preplan). This scram was pre-planned and was conducted in accordance with the normal shutdown procedure; it was not taken as a reaction to plant conditions that were, or were believed to be, precursors to an automatic scram and was not directed by an abnormal or emergency operating procedure. Therefore, FENOC believes that this shutdown does not represent an Unplanned Scram.

The shutdown was not counted as an Unplanned Power Change due to the following guidance from NEI 99-02, Revision 4.

Page 16, line 3, states that the indicator monitors the number of unplanned power changes (excluding scrams). Since this shutdown was a planned manual scram, it is excluded from the indicator.

Page 16, lines 9 and 10, defines the indicator as excluding manual and automatic scrams. Since this shutdown was a planned manual scram, it is excluded from the indicator.

Page 16, line 15, tells the licensee to report the number of unplanned power changes, excluding scrams. Since this shutdown was a planned manual scram, it is excluded from the indicator.

Page 17, line 18, excludes manual scrams. Since this shutdown was a planned manual scram, it is excluded from the indicator.

Page 18, lines 31 through 33, directly addresses this situation. It states that if an off-normal condition occurs above 20% power, and the plant is shutdown by a planned reactor trip using normal operating procedures, only an unplanned power change is counted. The unplanned power change from 86% to 55% was counted; in accordance with this section, the planned reactor trip using normal operating procedures was not counted.

FENOC determined that this issue should count as an unplanned power change because the power change from 55% to 0% occurred within 72 hours of identifying the issue (i.e., the recirculation pump trip)

Should this scram be counted as an unplanned scram or as an unplanned power change, or should it not be counted toward either indicator?

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

The licensee and the NRC senior resident inspector agree on the facts described in this FAQ. However, the NRC senior resident inspector believes that the circumstances of the event were not representative of a scram that was an intentional part of a planned evolution as directed by a normal operating procedure. Some elements of the event that the senior resident inspector considered included: 1) the scram was not conducted using procedure Integrated Operating Instruction (IOI) IOI-4, "Shutdown." It was conducted from a higher reactor power level using IOI-8, "Shutdown by Manual Scram," which directed operators to follow Off-Normal Instruction ONI-C71-1, "Reactor Scram;"[2] 2) the scram was not consistent with the approved reactivity plan for power ascension; and 3) the off-normal plant configuration (single loop) and shutdown conditions were a result of an unintentional recirculation pump loss that occurred less than 2 days prior to the unplanned scram.

Potentially relevant existing FAQ numbers

The NRC resident inspector believes FAQ 5 is potentially relevant. FAQ 5 addresses a plant that was in an LCO requiring the plant to be in Mode 2 within 7 hours. The plant used a standing operational procedure to assure that the LCO was met, and executed a manual scram in accordance with that procedure. This scram was considered not to count since the plant shutdown to comply with the

[2] Footnote added to clarify procedural usage - IOI-4 is the soft shutdown procedure. The procedure that is normally used to shutdown the plant is IOI-8, which is used for planned scrams – such as leading into a refueling outage when a soft shutdown is not used. ONI-C71-1 is entered following a scram – whether initiated by off-normal instructions, plant emergency instructions or IOI-8.

Technical Specification LCO was conducted in accordance with the normal plant shutdown procedure, which includes a manual scram to complete the shutdown. The FAQ response also states that if the actions to meet the Technical Specification LCO required a manual scram outside of the normal plant shutdown procedure, then the scram would be counted as an unplanned scram. FENOC does not believe that FAQ 5 is relevant because Perry was not in an LCO requiring a shutdown at the time of the scram. However, FENOC believes that the principle espoused by this FAQ is that manual scrams conducted in accordance with the normal plant shutdown procedure do not count and manual scrams that are not conducted in accordance with the normal plant shutdown procedure do count. The June 29, 2007 scram was conducted in accordance with the normal plant shutdown procedure.

The NRC resident inspector believes FAQ 275 is potentially relevant. FAQ 275 addresses a plant that is reducing power for a planned refueling outage, and is planning to insert a manual scram at 25 percent power in accordance with the plant shutdown procedure. At 28 percent power, as a result of a report from the field, operators believe they are about to have an equipment failure that would lead to an automatic scram. The operators immediately inserted a manual scram. FENOC does not believe FAQ 275 is relevant because, unlike the Perry shutdown, in the FAQ the plant was scrammed because the operators believed that they were about to have an equipment failure that would lead to an automatic scram. Therefore, the scram in FAQ was not in accordance with the normal plant shutdown procedure. This FAQ reiterates the principle that scrams count for this PI when the normal shutdown procedure is not used.

Response Section

Proposed Resolution of FAQ

The plant was shutdown via a planned manual scram in accordance with normal operating procedures and does not count as an Unplanned Scram for the purposes of the performance indicator.

If appropriate, provide proposed rewording of guidance for inclusion in next revision.
Clarify if the word "scram" as used in the following locations refers to all scrams, or if it implies an unplanned scram that is counted toward IE-1.

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.

FAQ 76.0

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.

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 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:
Monitoring Requirements:

Control Room:

- 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.

In Plant:

- 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

Response Section:

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.**

FAQ 76.4

Plant:	Salem		
Date of Event:	N/A		
Submittal Date:	January 14, 2008		
Licensee Contact:	Steve Mannon	Tel/email:	856-339-1129 steven.mannon@pseg.com
NRC Contact:	Dan Schroeder	Tel/email:	856-935-5151/ DLS@NRC.gov

Performance Indicator: MS06 Mitigating Systems Performance Index (Emergency AC Power Systems)

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

FAQ requested to become effective when approved or _____

Question Section

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

This FAQ proposes a guidance change to clarify when a change from Option 1 to Option 2 of Section F 2.3.3 can be implemented if no change to the PRA is required and the information to implement specific failure mode values is contained in the MSPI basis document.

NEI 99-02 Rev. 5, Section 2.2 Mitigating Systems Cornerstone, Mitigating Systems Performance Index, (Page 30 lines 35 to 40 and page 31 lines 1-6)

"*The MSPI calculation uses coefficients that are developed from plant specific PRAs. The PRA used to develop these coefficients should reasonably reflect the as-built, as-operated configuration of each plant. Updates to the MSPI coefficients developed from the plant specific PRA will be made as soon as practical following an update to the plant specific PRA. The revised coefficients will be used in the MSPI calculation the quarter following the update. Thus, the PRA coefficients in use at the beginning of a quarter will remain in effect for the remainder of that quarter. Changes to the CDE database and MSPI basis document that are necessary to reflect changes to the plant specific PRA of record should be incorporated as soon as practical but need not be completed prior to the start of the reporting quarter in which they become effective. The quarterly data submittal should include a comment that provides a summary of any changes to the MSPI coefficients. Any PRA model changes will take effect the following quarter (model changes include error, correction, updates, etc.)*"

Event or circumstances requiring guidance interpretation:

It is possible that the risk significance driven from system unreliability can be over stated in MSPI. Specifically, the difference in using Option 1 versus Option 2 of NEI 99-02 Section F.2.3.3 can result in conservative failure values for risk sensitive systems being used which produce an outcome that can deviate up to two orders of magnitude.

Section F3 of NEI 99-02 Rev. 5 notes that "it is not appropriate that a system should be placed in a *white* performance band due to expected variation in measured performance. This problem is most noticeable for risk sensitive systems that have few demands in the three year monitoring period." A relatively low risk significant incremental failure may result in a change from a very low safety significance performance band to the substantial safety significance performance band. This results because the limit of 5.0E-07 applicable to the most significant failure is not applied where the calculated MSPI value is greater than 1.0E-05. This result is contrary to the intent and stated purpose of section F3: ,"A MSPI> 1.0E-06 will still be a possible result *if there is significant unavailability, or failures in other components in the system."*

NEI 99-02 Section F 2.3.3 Option 1 applies a set of maximum values for all failure modes and Option 2 assigns a separate ratio for each specific failure mode. Application of the risk significance multiplier specifically applicable for each failure mode more accurately models the risk contribution of the failure modes and better implements the intent of NEI 99-02.

NEI 99-02 does not contain any specific guidance that precludes switching between Options 1 and 2 of Section F 2.3.3. Switching from Option 1 to Option 2 of NEI 99-02 Section F 2.3.3 is not a change in 'non-PRA information' as discussed in FAQ 432 (below) since the specific failure mode values are coefficients contained in the PRA. Selecting either Option 1 or Option 2 is a matter of implementing the already approved methods defined in NEI 99-02. If the specific failure mode values for a system are listed in the MSPI basis document in effect at the start of a quarter then a plant should be allowed to report their quarterly data with either Option 1 or Option 2 provided the change in option is documented in the quarterly submittal and the basis document is subsequently updated to reflect which Option was utilized.

Question:

Can a plant change from NEI 99-02 Section F 2.3.3 Option 1 to Option 2 in the current quarter if this change is not the result of a revision to the PRA and the specific values were contained in the MSPI basis document? Currently, there is no specific guidance in NEI 99-02 that precludes changing between the documented options.

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

Region 1's position is that changing between NEI 99-02 Section F 2.3.3 Options is a revision to the MSPI basis document which may only be performed for the PI quarterly submittal for the quarter following the revision to the MSPI basis document.

Potentially relevant existing FAQ numbers

432 regarding changes to the MSPI CDE calculator due to either revisions to the PRA coefficients or changes to non-PRA information.

433 LaSalle – discussed allowing the use of the previous PRA model for third quarter 2007 due to a non-conservative error discovered in the revised PRA model. Disposition of FAQ was that the model in effect at the start of the third quarter 2007 had to be used.

Response Section

Proposed Resolution of FAQ

Add a clarification at the end of Section 2.2 that specifically allows changing from NEI 99-02 F2.3.3 Option 1 to Option 2 when the failure mode specific PRA values are contained in the MSPI basis document.

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

However, changes to the basis document that do not affect specific PRA values are permitted and can be updated in CDE at any time.

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.

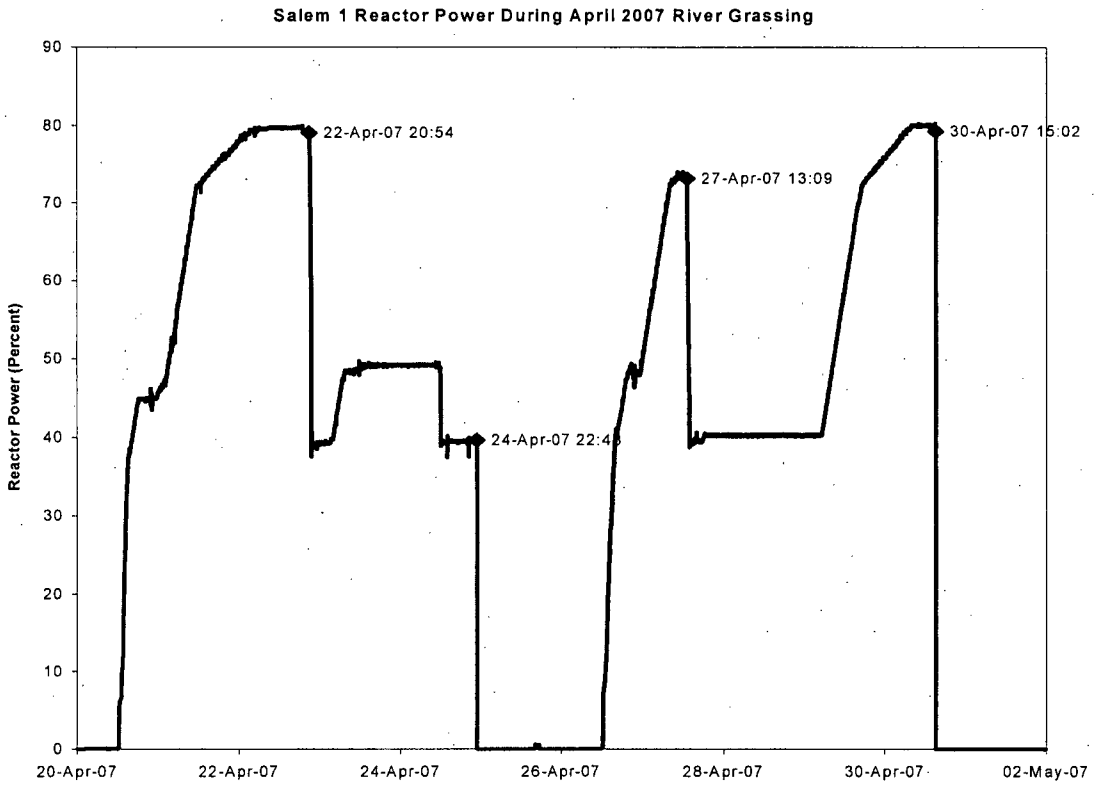
The seasonal readiness guide directs that the proper resources are in place from the Operations, Maintenance and Engineering Organizations to support the grassing season. These resources are assigned during the grassing season to support walk downs of the circulating water structure, determine the priority 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.

Attachment 2



FAQ 78.0

Removed following ROPTF discussion

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 has taken all reasonable actions to proactively assess the effect of Pacific storms on DCPP and has programs/procedures in place to take 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 that they are in a state of readiness to respond to storm conditions. In this case, the storm reached a magnitude that was significantly higher than predicted and resulted in the need to implement a controlled power reduction in response to a monitored plant parameter. Thus, the reporting of this power reduction as resulting from a storm-induced marine/biological debris intrusion satisfies the exclusion for reporting under PI IE03 "Unplanned Power Changes per 7000 Critical Hours."

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

The DCPP NRC SRI concludes that the power change should be counted against the unplanned power change PI since the accumulation of marine debris was reactive to the sudden discovery of off-normal conditions.

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.

Plant: Vermont Yankee
Date of Event: 2/12/07
Submittal Date: 01/30/08
Licensee Contact: Wayne Limberger **Tel/email:** 802-451-3136 / wlimber@entergy.com
NRC Contact: Beth Sienel **Tel/email:** 802-258-5144 /bsien90@entergy.com

Performance Indicator: MSPI

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

FAQ requested to become effective: When approved

Question Section

NEI 99-02 Guidance needing interpretation (include page and line citation): F2.2.2, Page F-28, lines 5 through 15.

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

Event or circumstances requiring guidance interpretation:

Vermont Yankee did not meet the run time requirement for an Emergency Diesel Generator (EDG) while performing a surveillance test run. This occurred due to incorrect positioning of a non-monitored manual component within the EDG system boundary as part of concurrent surveillance testing for an associated, non-monitored system. The event occurred under circumstances that were not representative of a normal start/load-run/run demand scenario, and did not result in malfunction, physical degradation or damage-related failure requiring repair of an active, monitored EDG component.

During a periodic operational surveillance run of an EDG (no maintenance was conducted prior to the run), a separate surveillance, the Fuel Oil Transfer (FOT) Pump IST capacity test, was being conducted concurrently. This test requires a reduction in the Fuel Oil Day Tank level by isolating the fill line and running an EDG to achieve sufficient available tank volume to support a meaningful capacity test run. In order to isolate the Day Tank, the fill line manual isolation valve is closed to remove the auto-replenishment of the Day Tank on low level. Normally, an EDG must be run prior to starting the capacity test to bring Day Tank volume down to a predetermined level, but it is procedurally required to be stopped before the capacity test is begun. In this case, Operations decided to take advantage of the Day Tank level draw-down that resulted from the ongoing EDG surveillance test run without shutting down the EDG.

During the course of the capacity test, when the Day Tank fill line isolation valve (FO-14A) was to be throttled to regulate pump discharge pressure, the operator incorrectly throttled then fully closed the EDG fuel oil supply line manual isolation valve (FO-40A), a non-monitored, excluded

component within the EDG system boundary. This is a normally locked-open valve that was inappropriately unlocked to manipulate it. The running EDG then tripped on a lack of fuel. The trip did not involve malfunction, physical degradation or damage-related failure of an active, monitored component in the EDG train, and required no repairs. The running EDG had met all surveillance requirements up to the point when the inadvertent suction valve closure occurred, and there was no indication that it would not have continued to run for the required time.