TempNo.	PI	Topic	Status	Plant/ Co.
76.0	IE03	Discovery of an Off-normal condition	1/16 Introduced and discussed 2/20 Discussed 3/19 Discussed 4/16 Tentative Approval	Quad Cities
77.0	IE03	Grassing Event	2/20 Introduced and Discussed 3/19 Discussed 4/16 Tentative approval	Salem
78.1	IE03	Storm Induced Marine/Biological Intrusion	2/20 Introduced and discussed 3/19 Discussed 4/16 Tentative approval	Diablo Canyon
79.0	IE03	Over-Voltage due to Lightening	3/19 Introduced 4/16 Tentative approval	Robinson
79.2	IE03	Threadfin Shad Run	3/19 Introduced and Discussed 4/16 Tentative approval	Brown's Ferry
79.3	IE03	Historical Downpowers	3/19 Introduced and Discussed 4/16 Tentative approval	Brown's Ferry
80.1	IE01	Reactor Power Indication	4/16 Introduced and Discussed	Columbia
81.0	EP01	ERO Assignment	5/15	Generic
81.1	IE04	Run Hours	5/15	Generic
81.3	IE03	Raccoon Intrusion	5/15	Grand Gulf
81.4	IE02	Environmental FAQ	5/15	Generic

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 licensee created a troubleshooting plan to assess the impact of the failed valve. One option on this plan, when implemented, would have involved a plant downpower and shutdown. The time between the creation of the troubleshooting plan which recognized the potential need to shutdown and performance of the downpower was greater than 72 hours. Therefore, the downpower does not count against the performance indicator.

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

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

The NRC Senior Resident has reviewed the proposed FAQ as written. Although the facts presented are accurate, the proposed FAQ does not appear to align with the most recently approved industry FAQs. The recently approved industry FAQs appear to have been approved on the basis of implementing a proactive down power of the unit, however, in the case of Salem Unit 1, the down powers were commenced as a reaction to the grassing events.

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

Response Section
The downpowers were caused by environmental conditions, beyond the control of the licensee, which could not be predicted greater than 72 hours in advance. Procedures were in place to address this expected condition; however, the magnitudes of the grassing events were unique in severity. The licensee had taken all reasonable actions to proactively prevent the downpower, and all equipment was maintained and operational. Therefore, these downpowers do not count against the performance indicator.

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

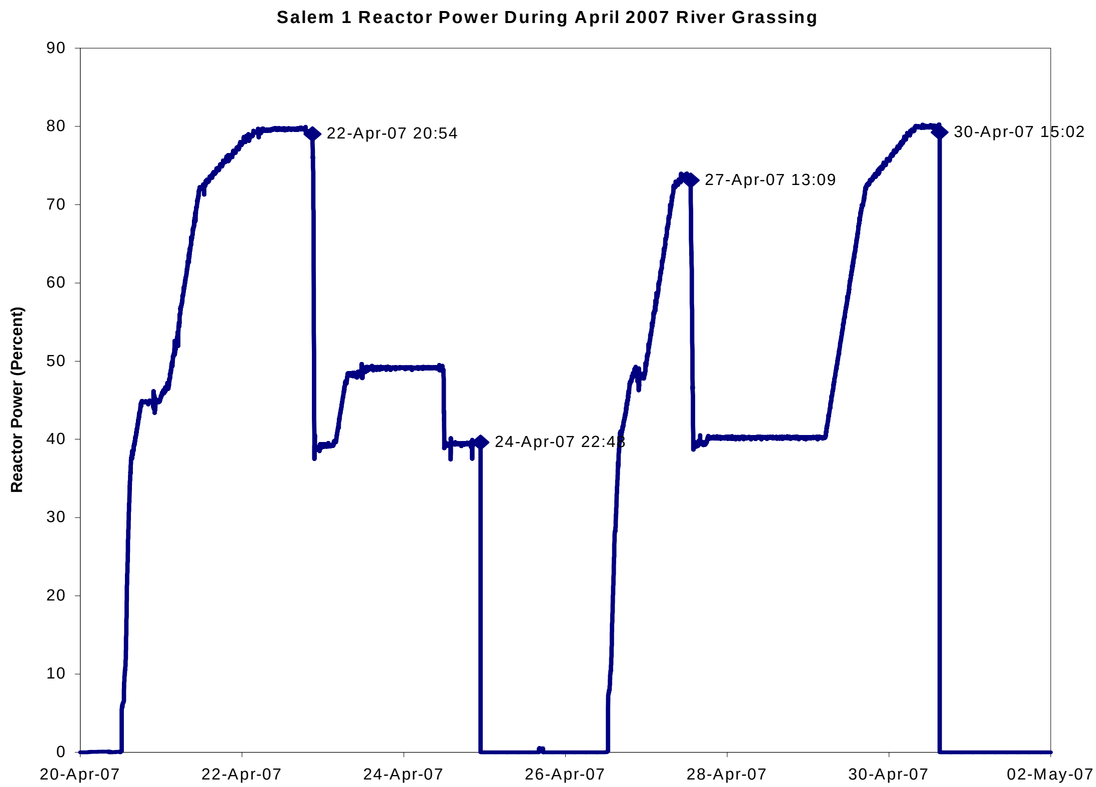
River conditions are routinely monitored as described in the River Conditions Update procedure (NC.LR-DG.ZZ-0015). When the instantaneous detritus weight exceeds a certain limit or the rolling weekly average exceeds certain levels, the sample collector must notify Salem Operations of elevated grass levels. 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



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 03, 2008, the DCPP Operations Manager held an operational decision making meeting (ODM) to discuss a Pacific storm front that was anticipated to move through the power plant general area. Environmental Operations Department and Plant Operations determined that although the magnitude of this storm front was significant, coastal kelp loading would not be an impact to plant operations. Previous storm fronts had removed much of the kelp loading in the coastal region around Diablo Canyon. 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. On January 05, 2008, as the storm front began moving through DCPP, a second ODM was held to confirm the previous decision to continue full operation of both DCPP units.

As the storm surge came through the DCPP general area 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. 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

<u>Response Section</u>

The downpower was caused by environmental conditions, beyond the control of the licensee, which could not be predicted greater than 72 hours in advance. Procedures were in place to predict and address this expected condition; however, the magnitude of the marine/biological intrusion changed rapidly and defied predictions. The licensee had taken all reasonable actions to proactively prevent the downpower, and all equipment was maintained and operational. Therefore, this downpower does not count against the performance indicator.

FAQ 79.0

Plant: H. B. Robinson Steam Electric Plant, Unit No. 2
Date of Event: 6/30/2007
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
Performance

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.

<u>Question Section</u>

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:

The downpower was caused by environmental conditions beyond the control of the licensee, which could not be predicted greater than 72 hours in advance, and could not have been mitigated by a proactive procedure. Therefore, this unplanned power change does not count.

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 79.2

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:

The downpower was caused by environmental conditions, beyond the control of the licensee, which could not be predicted greater than 72 hours in advance. A combination of conditions previously not experienced by the licensee contributed to the large influx of fish into the travelling water screens. Lessons learned from this event, including improved communications with TVA River Operations, have enhanced the licensee’s ability to predict these conditions in the future. Therefore, this downpower does not count against the performance indicator.

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

None required

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 January 3, 2008, Operators at the Browns Ferry Nuclear Plant (BFN) received "TRAVELING SCREEN DP HIGH" alarms and indications of lowering condenser vacuum on all three units. In accordance with general (i.e., not abnormal or emergency) plant operating procedure 2-GOI-200-12, *"Power Maneuvering,"* operators lowered reactor power on Unit 2 to approximately 50%. This action was accomplished in order to maintain condenser vacuum above the turbine trip set point. Unit 2 was returned to 100% power on January 4, 2008, 7:13 AM. The high differential pressure across the screens and the lowering condenser vacuum resulted from Threadfin shad being pulled into the traveling water screens and blocking water flow. On January 6, 2008, at 10:00AM, BFN Unit 2 commenced a subsequent power reduction to 65% in accordance with general plant operating procedures to allow condenser water box cleaning. The cleaning was necessitated by the intake of the fish on January 3, 2008. Unit 2 was returned to 100% power on January 7, 2008, 2:36 AM.

After the power reduction, BFN conducted a review of the event. During this review, it was found that on or before January 3, 2008, 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.

Threadfin shad may experience thermal 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 event, the fish stun likely began during the morning hours of January 2, 2008, 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.

Leading up to the event (on 12/31/07) the river flow was about 10,000 cubic feet per second (cfs) and the ambient river temperature was about 51˚F. Due to the low river flow, pooling of heat (warm water) from the plant diffusers had moved upstream and engulfed the plant intake skimmer wall. This is shown by the temperature change at Station 19, which was from 4˚F to 8˚F warmer than the ambient river temperature. Note that at Station 14, 1.8 miles upstream of the intake skimmer wall, there is no evidence of warm water from the plant (i.e., very little temp change from ambient). Pooling of heat occurs in the river because the diffusers are entraining (i.e., "pulling-in") and warming a volume of river water much greater than what is being supplied by the river flow. This pool of warm water spreads outward (i.e., upstream, downstream, and sideways) until a balance is obtained via heat loss to the ambient water and to the atmosphere.

Due to a cold front entering the valley (and a consequent increase in system power demand), hydro generation "picked-up" late in the afternoon of December 31, 2007. As a result, river flow was increased from 10,000 cfs to between 16,000 cfs and 20,000 cfs. This river flow was sufficient to "push" the pool of warm water downstream of the plant intake skimmer wall. In the early hours of 1/1/08, this eliminated the 4˚F to 8˚F "swell" in river temperature noted above (see Station 19 plot). At the same time, the cold front also reduced the temperature of the ambient river water by about 5 F, from about 51˚F on December 31, 2007 to about 46˚F on January 2, 2008. Thus, the aquatic wildlife in the vicinity of the intake was exposed to a total temperature drop of between 9˚F and 13˚F within about 24 to 36 hours. Most likely, this is what "stunned" the shad, making them lethargic.

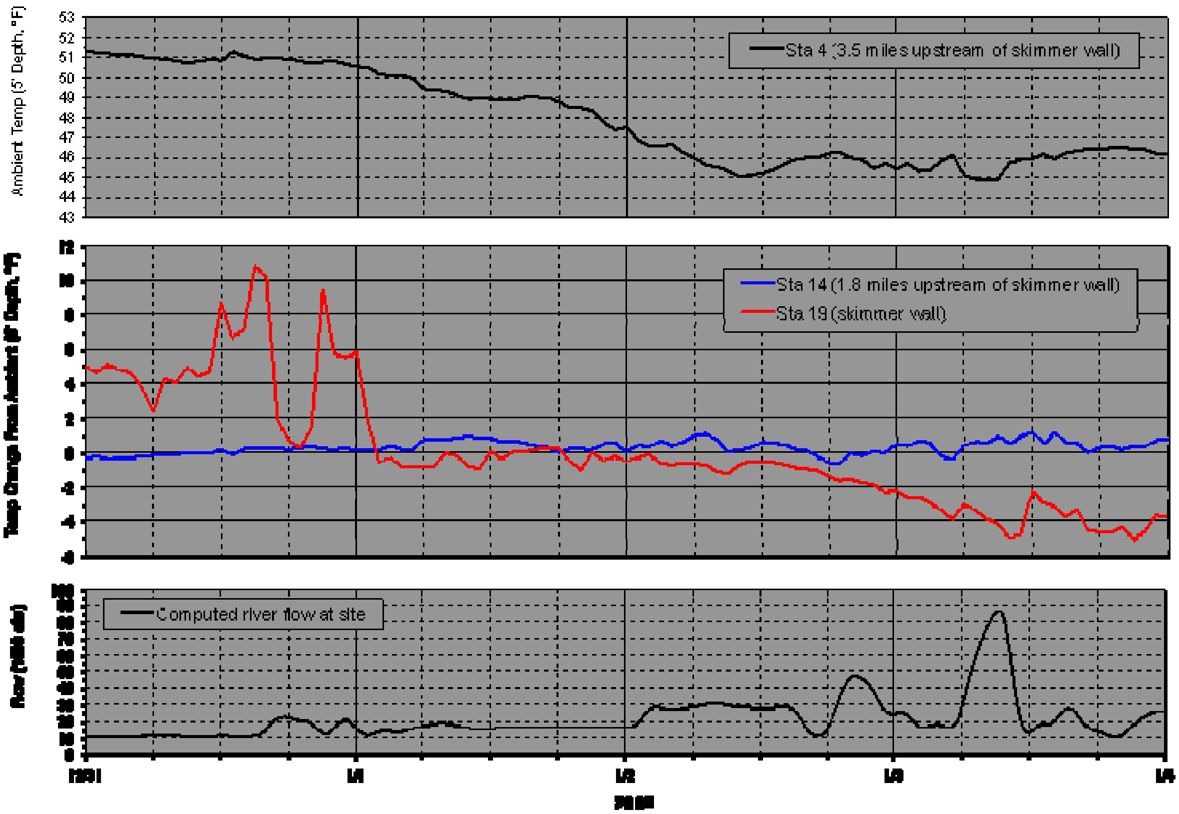
Late in the day on January 2, 2008, hydro peaking operations produced peak river flows near 47,000 cfs, lowering the water temperature at Station 19 (i.e., intake skimmer wall) 2˚F below the ambient temperature. Late in the morning on January 3, 2008, hydro power peaking operations produced peak river flows near 87,000 cfs, lowering the water temperature at Station 19 another 2˚F (a total of about 4˚F below the ambient temperature). In these events, the water entering the skimmer wall is below the ambient temperature because at high river flow, the plant withdrawal zone encompasses primarily the shallow overbank areas upstream of the intake. For extreme cold meteorology, the temperature of the water in these shallow areas will be colder than in the main channel of the river. At this point, however, the shad were probably already lethargic (due to the larger drop in temperature between late December 31, 2007 through January 2, 2008).

The charts below summarize the key data. They include three plots:

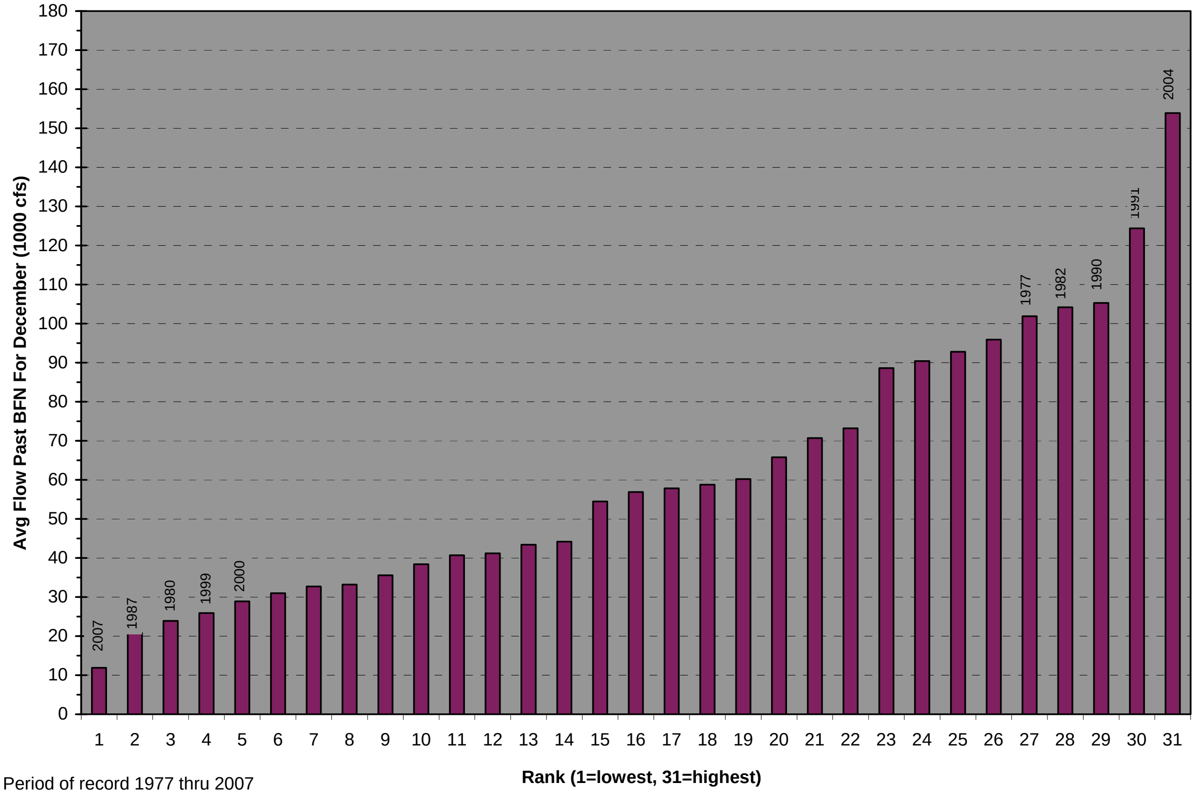
(1) The ambient temperature upstream of the zone of influence of the plant (Station 4--main channel, 3.5 miles upstream of the intake skimmer wall),

(2) The change in temperature from ambient to Station 14 (main channel, 1.8 miles upstream of the intake skimmer wall) and from ambient to Station 19 (intake skimmer wall),

(3) Computed river flow at the plant



The drought conditions that existed in the Tennessee Valley during 2007 were most likely a contributing factor in the shad event. The drought conditions in the area were more severe this past year than any time previous in Brown Ferry's operational experience. River flows in the months preceding the event were well below normal. For example, the average river flow past the plant in December 2007 was the lowest in 31 years (see below).



In combination with the waste heat from the plant diffusers, this low flow would have created a larger than normal warm water sanctuary for the shad (e.g., because of low river flow, less heat was flushed downstream) establishing the conditions for a thermal shock event to occur.

While the exact cause for the thermal shock cannot be determined, it can be speculated that either the river flow changes or the cold front or a combination of the two was the cause. As noted above, TVA River Operations had significantly varied river water flows for several days prior to the event to support meeting peak power demands and a cold front had moved into the area. The lower than normal river flows caused by the drought conditions in the valley established conditions such that either mechanism could have caused the temperature change.

BFN Operations normally receives daily river flow projections from TVA River Operations. However, prior to this event, this communication was strictly focused on the need for cooling tower operation to support meeting environmental thermal discharge limits.

Prior to this event, there was little to no ability to predict shad runs similar to that experienced in this event. Lessons learned from this event have enhanced our awareness of some of the combination of conditions that make these runs possible. The cause of this, and similar, runs cannot be absolutely determined, but lessons learned from this event have resulted in actions that have improved our ability to predict and respond to events in the future. These corrective actions focus on better communication with River Operations regarding planned changes to river flows and better preparations when weather conditions may be suitable for a natural temperature drop below 45.5˚F. However, these actions are only able to better prepare BFN to mitigate the consequences of such an event should it occur, and can not absolutely prevent future events.

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:

The downpowers, caused by environmental conditions and National Pollutant Discharge Elimination System (NPDES) restrictions for plant thermal discharge, were beyond the control of the licensee and could not be reasonably predicted greater than 72 hours in advance.

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

None required

FAQ 80.1

Plant: __Columbia Generating Station______
Date of Event: __March 22, 2008__________
Submittal Date: __April 10, 2008__________
Licensee Contact: _Greg Cullen_
Tel/email: _(509)377-6105 / gvcullen@energy-northwest.com
NRC Contact: __Zach Dunham, SRI___
Tel/email: _(509)377-2627

Performance Indicator: 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):
Revision 5, Page 15, Lines 14 and 15: "Licensees should use the power indication that is used to control the plant to determine if a change of greater than 20% of full power has occurred."

Event or circumstances requiring guidance interpretation:
On March 22, 2008 Reactor Feedwater (RFW) pump 1B (RFW-P-1B) experienced a speed transient which caused both RFW pump low suction pressure alarms to actuate. In response, control room staff initiated a reduction in reactor recirculation pump speed (both pumps) to reduce core flow (which reduces power) as directed by procedure. The core flow reduction was terminated after both RFW pump low suction pressure alarms cleared, as allowed by procedure. Upon termination of the flow reduction the operators assessed key plant parameters, including reactor power using the 1-minute average core thermal power (CTP) signal, and, after about 15 minutes, the 15-minute average CTP signal, and concluded that plant power was at 81% (as documented in the Condition Report and operating logs). The 1-minute and 15-minute average CTP signals are calculated using the reactor heat balance and are the normal signals used by operators to monitor and control plant power level. The 1-minute average CTP signal is driven by RFW flow and does not provide an accurate power calculation during RFW flow transients. It was not used by operators to assess power conditions during the initial RFW flow transient.

Subsequently, the control room staff requested that the Station Nuclear Engineer (SNE) provide an evaluation of peak power achieved during the transient to determine if reactor power exceeded 102% of the operating license limit. The SNE ultimately provided a plot of reactor power using an APRM simulated heat flux signal, which is not a signal used to control reactor power, nor is it a signal that is normally monitored by Operations personnel. The APRM simulated heat flux signal (a six second average of a single APRM signal, available for two of the APRMs) indicated that power had initially increased before the RFW control system recovered and brought speed (and power) back down. Since the RFW pump low suction pressure alarms did not clear at that point, operators reduced core flow. The APRM simulated heat flux signal indicates that power then went 1-3% below 80% RTP before settling out at approximately 81% RTP as conditions stabilized. Immediately following the transient the APRMs and APRM recorders were consulted for the purpose of assessing the condition of the core, but not for the purpose of assessing plant power level.

As cited above, guidance on what indications to use to determine if a change of greater than 20% of full power has occurred is "Licensees should use the power indication that is used to control the plant…." In this event the operators documented a reduction in power to approximately 81% RTP using indications available to them immediately following the transient (i.e., the 1-minute average). In addition, per Columbia operating procedures the primary power indication used to control and monitor the plant reactor power, including monitoring compliance with our license condition for reactor power, is the 15-minute average CTP signal, which is calculated using the reactor heat balance. This signal also indicated a reduction in power to approximately 81% RTP.

FAQ 227 (dated 10/31/2000) appears to be the question that led to the guidance quoted above. This FAQ asked, "For calculating the change in power, should secondary power data be used, nuclear instruments or which ever is more accurate?" The response was, "Licensees should use the power indication that is used to control the plant at the time of the transient." In this case the operators were not controlling the plant in response to indicated power but were reducing core flow in response to the alarms. Cessation of the flow (and power) reduction was dictated by the clearing of the RFW pump low suction pressure alarms. Upon checking power level following the transient, using the 1-minute average CTP signal, it was determined that power was reduced to 81% CTP (as documented in the CR and the operating logs). The APRM simulated heat flux signal was clearly not used to control the plant, nor was it initially consulted to determine final power level or the extent of the transient. The wording of the guidance and the FAQ 227 question and response would indicate that the licensee is not required to find or use the "more accurate" indications when assessing the power change, but should use initial indications of the power level. In this case the CR, operating logs, 1-minute average CTP signal, and 15-minute average CTP signal all indicate a reduction to 81% RTP.

RIS 2007-21 generated a significant amount of discussion about monitoring of instantaneous power in Boiling Water Reactors (BWRs) and resulted in some agreement that an average CTP calculation is the best way of monitoring power. However, these calculations have inherent inaccuracies during transient conditions, particularly RFW flow transients. APRMs serve a primary purpose of performing a reactor protective trip function and also have accuracy issues as far as indication of instantaneous core thermal power. As such, they provide more insights to transient conditions, but are not as accurate for absolute power indication, and, in fact, the APRMs are calibrated against the average CTP signal.

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

NRC Region IV has indicated that they do not agree with use of the 15-minute average CTP signal for assessing the event because events of a different type (multiple transients or power oscillations) would be invisible or inaccurately assessed. They cite the example discussion on page 14, lines 23-30 of NEI 99-02, Revision 5, as a case where a 15-minute average would not lead to assessment of two separate unplanned power changes of greater than 20% due to the signal averaging over a relatively long period of time.

In addition, NRC Region IV considers that the reference in NEI 99-02, page 15, lines 14-15, to "use the power indication that is used to control the plant" should include all indications that are normally available to the operators for controlling plant power. For example, in response to a quickly developing transient, such as during plant response to a component failure, power indication averaged over 15 minutes may not be appropriate for controlling power whereas APRM's may be a better indicator for the operators to use during the transient response. In contrast, during a slowly developing transient, such as a controlled reduction in power, a power average may be appropriate.

Potentially relevant existing FAQ numbers

227

Response Section

Proposed Resolution of FAQ

The purpose of the indicator is to monitor the number of “unplanned power changes (excluding scrams) that could have, under other plant conditions, challenged safety functions” with the intent of providing “leading indication of risk-significant events” (per NEI 99-02). The 20% power reduction value is chosen to provide some criteria for reporting, but does not constitute a calculated threshold of risk-significance. As such, the guidance provides clarification that the reduction in power can sufficiently be determined by initial indications during and following the transient and that detailed analysis of exact core conditions is not required to meet the intent of the indicator since the difference between a reduction of 19.9% and a reduction of 20.1% (for example) is not considered to be the difference between an event that is not risk-significant and one that is. The licensee is not required to use the indications that show the highest power reduction, or even is considered the most accurate, for these reasons.

In the described event the transient essentially involved a step change in power where the operator response was not driven by monitoring of reactor power, and initial indications following completion of the transient indicated that power stabilized at 81% power. This value was documented consistently in the post-event documentation. For this event it is sufficient to determine that the gross power change was approximately 19% and it does not need to be reported.

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

Guidance revision does not appear to be necessary at this point.

Plant: Generic
Date of Event: May 14, 2008
Submittal Date: May 14 2008
Contact: Julie Keys Tel/email 202-739-8128, jyk@nei.org
NRC Contact: Nathan Sanfilppio Tel/email: 301-415-3951

Performance Indicator: EP01
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 EP01 on pages 43 through 53 and on the pages listed below.

NEI 99-02, page 79, Line 31 states "The percentage of drill, exercise, and actual opportunities that were performed timely and accurately by Key Positions, as defined in the ERO Drill Participation indicator,
NEI 99-02, page 86, Line 11 states, "…ERO members assigned to fill Key Positions

Event or circumstances requiring guidance interpretation:
<u>Question</u>

If a licensee were to wait until the ERO assignment process was completed before crediting the DEP performance indicator for an ERO-member-in-training, then the opportunity could be counted in a reporting period other than the one in which the performance enhancing experience occurred. At North Anna, a performance enhancing experience was provided to new ERO member before they assumed their ERO position. The ERO member assumed their ERO position one day later; however, that day spanned reporting periods.
Question: How and when should DEP PI opportunities for ERO-members-in-training be counted?
<u>Response</u>

PI opportunities and participation credit should not be counted for ERO-members-in-training. DEP opportunities are only counted for plant staff members who are currently assigned to fill a key position on the ERO.

The participation PI tracks Key ERO members assigned to the ERO. The key word here is assigned. Trainees are not assigned to the ERO and therefore DEP opportunities or participation does not count.
Data reporting may be affected in accordance with this FAQ at some plants. There is no need to modify past record keeping practices based on this FAQ. Record keeping practices should only be modified.

Discussion

If a Key ERO member trainee participates in a performance enhancing experience as part of the qualification process, then the licensee may count the trainee's performance, (success or failure) in the Drill/Exercise PI (EP01) for the quarter in which the opportunity occurred. All trainee EP01 performance enhancing experiences must be determined in advance in accordance with NEI 99-02 clarifying notes.

If the trainee performance is counted as a success, then they may be assigned to the ERO. If the trainee performance is a failure, then they may undergo remediation prior to assignment to the ERO. If a performance enhancing experience is required for remediation, it may or may not be included in the EP01 PI, as described above. In either case, when the trainee is actually assigned to the ERO, then all their EP 01 performance enhancing opportunities, whether a success or failure are included in the EP01 metric in that quarter. For EP02, the trainee's most recent participation in a performance enhancing experience that was included in the EP01 PI, whether during qualification or remediation, would apply.

NEI 99-02 Revision 5 Changes:

NEI 99-02 Revision 5, page 43, Line 31 defines EP01 as "The percentage of all drill, exercise, and actual opportunities that were performed timely and accurately by Key Positions, as defined in the ERO Drill Participation indicator, during the previous eight quarters."

NEI 99-02 Revision 5, page 51, Line 3 identifies the purpose of EP02, "This indicator tracks the participation of ERO members assigned to fill Key Positions in performance enhancing experiences and through linkage to the DEP indicator ensures that the risk significant aspects of classification, notification, and PAR development are evaluated and included in the PI process. This indicator measures the percentage of ERO members assigned to fill Key Positions who have participated recently in performance-enhancing experiences such as drills, exercises, or in an actual event."

NEI 99-02 Revision 5, page 51, Line 11 defines EP02 as "The percentage of ERO members assigned to fill Key Positions that have participated in a drill, exercise, or actual event during the previous eight quarters, as measured on the last calendar day of the quarter."

NEI 99-02 Revision 5, page 51, Line 18 identifies the data reporting elements as "• total number of ERO members assigned to fill Key Positions
• total number of ERO members assigned to fill Key Positions that have participated in a drill, exercise, or actual event in the previous eight quarters

NEI 99-02 Revision 5, page 52, Line 24 provides Clarifying Notes," When the performance of ***ERO members assigned to fill*** Key Positions includes classification, notification, or PAR development opportunities, the success rate of these opportunities must contribute to Drill/Exercise Performance (DEP) for participation of those Key Positions to contribute to ERO Drill Participation." ***When a performance enhancing experience occurs prior to an ERO member being assigned to a Key Position in the ERO (qualifying drill), then the classification, notification, or PAR development success rate shall contribute to the Drill/Exercise (DEP) at the time the member is assigned to the ERO. Drill Participation credit will be the ERO members most recent participation in a performance enhancing experience that was included in the EP01 PI.***

Application of this resolution and revision to NEI 99-02 would ensure that the performance, positive or negative, of all ERO members assigned to fill Key Positions is actually reflected in the EP01 PI. It would provide a fuller indication of the state of proficiency of the ERO members assigned to fill Key Positions. It would also prevent deferral of performance enhancing experiences from incumbent ERO members assigned to fill Key Positions to newly-qualified ERO members assigned to fill Key Positions.

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

FAQ 411

Response Section

Proposed Resolution of FAQ

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

NEI 99-02 Revision 5, page 53, insert at Line 48 "Drills performed by an individual before being assigned to a Key Position in the ERO may be counted once the individual is assigned to the ERO as long as the performance enhancing experience(s) contributes to the Drill/Exercise (DEP) metric."

NEI 99-02 Revision 5, page 45 insert at Line 39 "When a performance enhancing experience occurs before an individual is assigned to a Key Position in the ERO, then opportunities for that individual that were identified in advance shall contribute to the Drill/Exercise (DEP) metric at the time the member is assigned to the ERO".

FAQ 81.1

Plant:	Generic
Date of Event:	NA
Submittal Date:	April 22, 2008
Licensee Contact:	Lenny Sueper/Julie Keys
NRC Contact:	Nathan Sanfilippo

Performance Indicator: MSPI

Site-Specific FAQ (Appendix D)? No

FAQ requested to become effective when approved.

Question Section

NEI 99-02 page F 21, lines 24 through 27 states *"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."*

The guidance currently does not specify how pump operational run hours should be counted when run as a continuation of post maintenance testing. Even though there will be no associated demand corresponding with these hours, they should be counted as run hours from the time the pump is declared operable.

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
None

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

Append the guidance as follows:

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."

Plant: Grand Gulf Nuclear Station
Date of Event: April 29, 2008
Submittal Date: May 14, 2008
Licensee Contact: Mike Larson **Tel/email:** 601-437-6685 / mlarson@entergy.com
Licensee Contact: Steve Osborn **Tel/email:** 601-437-2344 / sosborn@entergy.com
NRC Contact: Richard Smith **Tel/email:** 601-437-4620 / rich.smith@nrc.gov

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

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

FAQ requested to become effective when approved.

Question Section:

NEI 99-02 Rev 5 Guidance needing interpretation (include page and line citation):
Page(s) 14 & 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:

During the spring, the Mississippi River floods as ice melts in the north and spring rains greatly increase the river flow volume. The spring 2008 Mississippi River flooding has been more extensive than flooding seen since Grand Gulf Nuclear Station (GGNS) entered construction and operation. In fact, the Mississippi River levels were higher than any seen since 1973, when the river crested at 51.2 feet, well in excess of installed animal deterrence devices.

GGNS has a service water system that employs a radial well system for its cooling water during normal operation. These radial wells are located closer to the Mississippi River than the plant and are designed to remain functional during flooding in excess of that experienced in the spring of 2008. Although situated over dry land during most of the year, equipment to support the radial wells' operation is located on a platform approximately 26 feet above ground level sitting on pilings. The structure is protected from impact by barges or large debris being swept uncontrolled down the river by additional large pilings. A boat is required for station personnel to access the Radial Well Switchgear during times of river flooding.

At 2112 on April 29, 2008, GGNS experienced a loss of Balance of Plant (BOP) Transformer 23 resulting in a loss of the 28AG Bus and Radial Well Pumps E, F, and J. The Loss of Plant Service Water (PSW) Off-Normal Event Procedure (ONEP) was entered as well as the Reduction in Recirculation Flow ONEP. Reactor power was reduced to approximately 47% using Reactor Recirculation flow and control rod insertion. The plant responded as expected. Upon investigation into the loss of BOP Transformer 23, a dead raccoon was found in the vicinity of the transformer which clearly appeared to have come in contact with energized equipment.

The cause of the loss of BOP Transformer 23 is believed to be a short inducted by the raccoon. The flooding of the Mississippi River is believed to have allowed the raccoon to climb into the transformer area bypassing the installed prevention measures. Animal intrusion is normally prevented from the area by removal of ladder access and installed animal deterrence (approximately 8 to 10 feet high above ground) on the power poles adjacent to the transformer structure. These measures prohibit animal intrusion under normally anticipated and expected environmental conditions when animals would be present (.i.e., dry, non-flooded conditions). It was not anticipated or expected that an animal would gain access by swimming in the flooded conditions of the Mississippi River due to the river current. In order to reach the Radial Well Switchgear, the raccoon either was caught in the river current from up-river or swam a significant distance from the flooded wood line to reach the platform.

Based upon previous operating experience, GGNS has implemented measures to mitigate the potential for animal intrusion into critical outdoor equipment. Previous animal intrusions have occurred when the animal approached the area of concern via a land route. This is the first identified event where the animal swam into the area of concern. There has been no occurrence of Radial Well Switchgear water borne animal intrusions in the history of GGNS.

The Mississippi River flooding level with an animal intrusion is a unique environmental condition that has not been previously experienced and therefore, could not have been anticipated and mitigated by procedure or plant modification.

Does the GGNS down power of April 29th 2008 count as an Unplanned Power Change per 7,000 Critical Hours?

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

NRC Statement to be include in the Licensee's FAQ for the greater than 20% power decrease on April 29, 2008.

Facts:

- In 2002 and 2005, Grand Gulf Nuclear Station had reactor scrams due to raccoons causing ground faults to station transformers.
- The corrective actions for the first scram in 2002 did not prevent the scram that occurred in 2005.
- The licensee identified the BOP 23 transformer as vulnerable to animal intrusion following the 2002 reactor scram.
- The Mississippi river level routinely rises in the spring, requiring Grand Gulf employees to use a power boat to perform operator rounds and maintenance checks on equipment at the river.
- In June of 2006, the licensee found an injured raccoon at the base of the BOP 23 transformer. The raccoon had burn marks on its nose and hind legs. The raccoon had come into contact with live current from either the primary or secondary side of one of the platform transformers but did not cause a trip of equipment.
- In response to this event in June of 2006, the licensee placed animal guards on the wooden electrical poles by the transformer platform believed to be approximately 8-10 feet from the ground. They also removed a section of ladder going to the platform approximately 4 feet 7 inch from the ground.

The region and the resident staff have concluded that the environmental conditions which have been previously experienced at the site could have been anticipated by the licensee to mitigate the unintended down power. The staff disagrees with the licensee's assertion that the combination of a routine flooding event and repetitive animal intrusion equates to a unique environmental condition. The staff has concluded that, based on the above listed facts, the licensee should have developed corrective actions to mitigate the loss of the BOP transformer by adding animal deterrents that would be effective during flooding events. This would have prevented the occurrence of the April 29, 2008 down power event.

Potentially relevant existing FAQ numbers: None

Response Section:

Proposed Resolution of FAQ: No. Flooding, which allowed waterborne animals to bypass submerged animal deterrence devices, has never been previously experienced and qualifies as a unique environmental condition and could not have been anticipated and mitigated by procedure or plant modification. However, should these same conditions recur, the licensee is expected to have in place any additional modifications to the Radial Well Switchgear, the necessary practice, procedures, staff, and equipment to handle potential animal intrusions resulting from environmental flooding conditions that future unplanned power changes of greater than 20 percent may not be necessary. Development and implementation of such modifications and procedures in the future, may provide a basis for a future FAQ allowing excluding a downpower >20% for this PI.

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

None.

FAQ 81.4

Plant: Generic
Date of Event: NA
Submittal Date: May 6, 2008
Licensee Contact: Julie Keys
NRC Contact: Nathan Sanfilippo

Performance Indicator: MSPI

Site-Specific FAQ (Appendix D)? No

FAQ requested to become effective when approved.

Question Section

NEI 99-02 page 14, lines 42 through 49 and page 15, lines 1 through 4 state: *"Anticipated power changes greater than 20% in response to expected environmental problems (such as accumulation of marine debris, biological contaminants, or frazil icing) which are proceduralized but cannot be predicted greater than 72 hours in advance may not need to be counted unless they are reactive to the sudden discovery of off-normal conditions. However, unique environmental conditions which have not been previously experienced and could not have been anticipated and mitigated by procedure or plant modification, may not count, even if they are reactive. The licensee is expected to take reasonable steps to prevent intrusion of marine or other biological growth from causing power reductions. Intrusion events that can be anticipated as 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. 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."*

The NEI ROP Task Force and the NRC staff have in the past reviewed many repeat FAQs from various plants related to the exception in IE02, Power Changes Greater than 20%, from counting events caused by expected environmental problems. Typically FAQs are generated not because the site's resident inspector feels the plant's response was inadequate but because NEI 99-02 dictates it. The generation of such FAQs is an inefficient use of the industry's and NRC's time. Once the original FAQ (and implicitly the plant's plans and procedures for dealing with future similar events) has been approved, the site resident inspector should be allowed to make the determination whether the plant's response was timely and adequate. An FAQ should only be required if the resident inspector and plant do not agree the guidance has been met as is the case with the other indicators.

Response Section

The subject text should be replaced with the following :

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.