FAQ LOG 07/07

TempNo.	PI	Topic	Status	Plant/ Co.
70.0	MSPI	Blown Fuse on Diesel	06/13 Introduced 07/18 Discussed	Ft. Calhoun
71.0	MSPI	Chemistry Excursion	07/18 Introduced and Discussed	Duane Arnold
71.1	1E03	Environmental Condition Downpower	07/18 Introduced and Discussed.	FitzPatrick
71.5	MS06	Emergency AC Power Modeling	07/18 Introduced and Discussed.	Oconee

FAQs on Appeal:

TempNo.	PI	Topic	Status	Plant/ Co.
69.2	MSPI	Fuel Oil Line Leak	Appeal date 08/02	Kewaunee

Plant: Fort Calhoun Station
Date of Event: July 21, 2004
Submittal Date: May 24, 2007
Licensee Contact: Gary R. Cavanaugh Tel/email: 402-533-6913 / gcavanaugh@oppd.com
NRC Contact: L. M. Willoughby Tel/email: 402-533-6613 / lmw1@nrc.gov

Performance Indicator: MSPI

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):

Clarification of the guidance is requested for "time of discovery." Is time of discovery when the licensee first had the opportunity to determine that the component cannot perform its monitored function or when the licensee completes a cause determination and concludes the component would not have performed its monitored function at some earlier time, similar to the situation described in the event section below.

Page F-5, Section F 1.2.1, lines 19-21:

> Fault exposure hours are not included; unavailable hours are counted only for the time required to recover the train's monitored functions. In all cases, a train that is considered to be OPERABLE is also considered to be available.

Page F-22, Section F 2.2.2, lines 18-19:

> Unplanned unavailability would accrue in all instances from the time of discovery or annunciation consistent with the definition in section F 1.2.1.

Page F-5, Section F 1.2.1, lines 34-40:

> *Unplanned unavailable hours:* These hours include elapsed time between the discovery and the restoration to service of an equipment failure or human error (such as a misalignment) that makes the train unavailable. Unavailable hours to correct discovered conditions that render a monitored component incapable of performing its monitored function are counted as unplanned unavailable hours. An example of this is a condition discovered by an operator on rounds, such as an obvious oil leak, that resulted in the equipment being non-functional even though no demand or failure actually occurred.

Event or circumstances requiring guidance interpretation:

On October 19, 2004, while reviewing detailed plant computer data related to the operation of the Emergency Diesel Generator Number 2 (DG-2), Fort Calhoun Station (FCS) discovered that DG-2 had become inoperable for 29 days beginning on July 21, 2004. On August 18, 2004 when DG-2 was started for the next monthly surveillance test, DG-2 started but failed to achieve proper voltage and frequency. At that time, DG-2 was declared inoperable, trouble shooting commenced, and three hours later following a fuse replacement, DG-2 was declared operable.

Data obtained from the FCS control room computer subsequently confirmed that the condition occurred as the operators were performing engine unloading and shutdown during completion of the monthly surveillance test (Attachment 1) on July 21, 2004. In attachment 2, there are highlighted sections of a print out which is an attachment to the July 21, 2004 surveillance test for clarification. As DG-2 was being shut down following the successful surveillance test, the control room staff received numerous expected alarms. The alarms in question are plant computer alarms and not tiled annunciator alarms. Since the alarms were expected as part of unloading and shutting down DG-2 they were acknowledged and treated as a normal system response.

The earliest opportunity for the discovery of the failed fuse condition was upon receipt of the plant computer alarms for DG-2 low output frequency and low output voltage which occurred following the opening of the DG-2 output breaker.

When attempting to complete the next monthly surveillance test in August 2004, DG-2 started but failed to achieve proper voltage and frequency. At that time, DG-2 was declared inoperable, trouble shooting commenced, and three hours later DG-2 was declared operable following fuse replacement. In an effort to determine unavailability hours for reporting of the Emergency AC Power MSPI, FCS determined that the unavailability began on August 18, 2004 when DG-2 was started for the next monthly surveillance.

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

<u>Issue #1:</u>

In the opening lines of the FAQ, the licensee references NEI 99-02, page F-5, lines 19-21, which states: *"Fault exposure hours are not included; unavailable hours are counted only for the time required to recover the train's monitored functions. In all cases, a train that is considered to be <u>OPERABLE is also considered to be available</u>."*

...and the licensee further references page F-5, lines 34-40, stating ...*"Unplanned unavailable hours: These hours include elapsed time between the <u>discovery</u> and the <u>restoration to service of an equipment failure</u> or human error (such as a misalignment) that makes the train unavailable. Unavailable hours to correct discovered conditions that render a monitored component incapable of performing its monitored function are counted as unplanned unavailable hours. An example of this is a condition discovered by an operator on rounds, such as an obvious oil leak, that resulted in the equipment being non-functional even though no demand or failure actually occurred."*

As described in NRC Inspection Report 05000285/2005010, Emergency Diesel Generator #1 was both <u>inoperable and unavailable</u> from July 21, 2004 until August 19, 2004. The inspection report also explained why discovery of the condition should reasonably have occurred on July 21, 2004:

"After a review of this event, the inspectors noted that the licensee had several opportunities to promptly identify the degraded voltage condition that affected the safety function of Emergency Diesel Generator 2. These opportunities included:

- The failure to recognize the alarm for low emergency diesel generator output voltage was indicative of a degraded voltage condition.
- The failure to recognize that the watt-hour meter turns off when emergency voltage goes below the watt-hour trigger setpoint, indicative of a degraded voltage condition.
- The failure to recognize that the emergency diesel generator output voltage meter indications were reading approximately half their normal value, indicative of a degraded voltage condition.
- The failure to recognize that data obtained during surveillance Operating Procedure OP-ST-DG-0002, performed on July 21,2004, showed the emergency diesel generator output voltage decreasing to approximately 2200 volts, indicative of a degraded voltage condition. This surveillance procedure was reviewed and determined satisfactory by three operations personnel and the system engineer."

Based on the multiple opportunities to identify this condition, the Resident Inspectors/Regional staff believe the conditions mentioned above would be indicative of an "obvious" condition, similar to the leaking oil condition example above. Therefore, the definition of unavailable hours would be met.

<u>Issue #2:</u>

In the licensee's FAQ, the licensee stated on page 2, *"... the control room staff received numerous <u>expected</u> alarms."* and then went on to say *"These expected plant computer alarms were received <u>within moments of when they normally would have occurred</u>."*
Please refer to the 4 bullets listed above. The control room alarms were not expected at the times that they occurred, and the significance of these conditions were neither recognized individually or collectively by multiple licensed operators. As described in the NRC Inspection Report 05000285/2005010... *"Emergency Diesel Generator 2 was operated at normal speed, unloaded, for approximately 12 minutes to cool down the turbo charger. During this time operators discussed the loss of indication on the watt-hour meter and decided to write a condition report on the discrepancy."* Given that the alarms/indications were present approximately 12 minutes early, the Residents/Regional staff do not agree with the licensee's assertion that this equates to "within moments of when they normally would have occurred."

<u>Issue #3:</u>

In the "Proposed Resolution" section of the FAQ, the licensee stated... *"Although the earliest opportunity to discover the failed fuse was July 21, 2004, FCS concluded that it would have been an improbable catch for them to do so. While changes were put into place following discovery of this condition to prevent recurrence, <u>it was determined that it would have been unreasonable to expect the control room staff to have caught this when it occurred</u>."* The licensee further stated... *"...this issue was appropriately classified as discovery on August 18, 2004."*

Region IV personnel believe that it was reasonable, as documented in the previous sections and in the inspection report, for the control room staff to have caught this when it occurred.

Issue #4:

In the licensee's FAQ, they stated: "... the Significance Determination Process (SDP) was used to characterize the risk of the event and this process evaluated the fault exposure period to determine that risk."

Once a performance deficiency is identified, the SDP assesses the risk of a condition, (i.e., how significant is it during the time that equipment was unable to perform its function), irrespective of whether the equipment is considered fault exposure time or unavailability hours. Region IV personnel consider that one of the salient aspects of the PI, an indicator of performance, is to identify both unavailability and fault exposure hours. The staff considers this period to be unavailability in regard to the PI.

Issue #5:

The licensee has considered the failure of DG-1 as a Failure-to-Load on August 19, 2004 in their calculations.

The Region IV staff considers this should be counted as a Failure-to-Run (FTR) on July 21, 2004 instead of a Failure-to-Load. Per the NEI guidance, Failure-to-Load items are those that prevent the engine from starting or running for an hour. The fuse failure occurred after the engine had run successfully for greater than one hour. While the "type" of failure does not directly affect the subject of this FAQ (calculation of hours for the PI), erroneous failure classifications could be misleading if they are to be considered with any subsequent failures.

Summary:

In summary, the licensee stated that *"... unavailability should accrue on August 18, 2004 when the failure occurred."* The licensee believes that the duration between July 21 and August 19, should be counted as Fault Exposure Hours. However, Region IV staff does not agree with this position. The licensee had ample opportunity to identify and correct this condition, as was stated in a previously cited 10 CFR 50, Appendix B, Criterion XVI violation. Region IV staff believes the duration that DG-1 was non-functional should be counted as Unavailability Hours.

Potentially relevant existing FAQ numbers

None

Response *Section*

Proposed Resolution of FAQ

Although the earliest opportunity to discover the failed fuse was July 21, 2004, FCS concluded that it would have been an improbable catch for them to do so. While changes were put into place following discovery of this condition to prevent recurrence, it was determined that it would have been unreasonable to expect the control room staff to have caught this when it occurred.

In a strict determination of the unavailability you would have to conclude that since an annunciation occurred, it should have been caught by the control room staff (i.e., time of discovery). However, when presented with the facts surrounding this case, FCS concludes that this issue was appropriately classified as discovery on August 18, 2004.

FCS has reviewed NEI 99-02, Revision 4 guidance and determined that in MSPI, unavailable hours are counted only for the time required to recover the train's monitored functions. Therefore, the "time of discovery" for the purposes of assigning unavailable hours starts from the time the diesel was declared inoperable on August 18, 2004. Unavailability, prior to the determination that the failure affected the ability of the diesel to perform its monitored function, is actually fault exposure, which is not included in the MSPI unavailability calculation. Since performance deficiencies were noted for this event, the Significance Determination Process (SDP) was used to characterize the risk of the event and this process evaluated the fault exposure period to determine that risk.

The information provided in lines 18-19 on page F-22 of section F 2.2.2. "Unplanned unavailability would accrue in all instances from the time of discovery or annunciation consistent with the definition in section F 1.2.1.", might be misunderstood to imply that any alarm originating in the control room would indicate that monitored equipment is obviously inoperable. In this instance the control room annunciation was from a computer monitored point and indicated "DG-2 Low Output Frequency and Low Output Voltage," as expected.

Consistent with the definition in F1.2.1 lines page F-5 lines 20 and 21 "In all cases, a train that is considered to be OPERABLE is also considered to be available." Therefore, the unavailability should accrue on August 18, 2004 when the failure occurred.

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

N/A

Fort Calhoun Station June 2007 FAQ
Attachment 1

Relevant Pages of July 2004 EDG2 Surveillance Test

FAQ 70.0

Fort Calhoun Station June 2007 FAQ
Attachment 2

Plant: **Duane Arnold Energy Center**
Date of Event: **3/18/07**
Submittal Date: **6/07/07**
Licensee Contact: **Robert Murrell Tel/email: 319-851-7900 robert_murrell@fpl.com**

NRC Contact: **Bob Orlikowski Tel/email: 319-851-7210 rjo@nrc.gov**

Performance Indicator: Unplanned Scrams per 7000 Critical Hours

Site-Specific FAQ (Appendix D?): No

FAQ requested to become effective: FAQ requested to become affective when approved.

Question Section

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

NEI 99-02, R4, pages 10 and 11, specifically page 10 lines 11-12 and page 11 line 2/line 5 and line 2/line 13-15.

Page 10, lines 11-12: "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."

Page 11, lines 13 – 15 [Line 2 "Examples of scrams that **are not** included:] "...Plant shutdown to comply with technical specification LCOs, if conducted in accordance with normal shutdown procedures which include a manual scram to complete the shutdown."

Page 11, line 5: [Line 2 "Examples of scrams that **are not** included:] "...scrams that are part of a normal planned operation or evolution."

Events or Circumstances requiring guidance interpretation:

Duane Arnold experienced a reactor water chemistry excursion (increasing conductivity readings while performing condensate demineralizer manipulations) at approximately 1630 on March 18, 2007. This excursion occurred with the plant operating at ~34% power during a post Refueling Outage startup. By 1630, the conductivity level quickly surpassed the Technical Requirements Manual (TRM) limits of >1 and >5 (μmoh/cm). This resulted in actions being initiated as required by the TRM for restoring the limits immediately and analyzing a sample within 8 hours. At the time, conductivity was > 10.

As a result of the out of specification chemistry parameters, the plant also entered the TRM LCO 3.4.1 Condition D requirement to be in Mode 3 within 12 hours and be in mode 4 within 36 hours.

During the entirety of this event, the conductivity limits that would require the plant to insert a manual scram or commence a fast power reduction as directed by Abnormal Operating Procedure (AOP) 639, "Reactor Water/Condensate High Conductivity," were never met. At Duane Arnold, fast power reductions can occur as a result of a need to shutdown the plant in an expedient manner. This can be driven by short duration TS and TRM LCOs, AOPs, or other plant conditions. Fast power reductions are accomplished using a normal shutdown procedure titled Integrated Plant Operating Instruction (IPOI) 4, Plant Shutdown, Section 6.0, "Fast Power Reduction." This IPOI consolidates information for a safe and efficient shutdown from 35% power operation to cold shutdown or other shutdown conditions, and is not an AOP.

As a result of the TRM requirements, the plant commenced a shutdown in accordance with IPOI 4, Section 6.0.

At 1940 on 3/18/07, a manual scram was inserted. This action was accomplished after careful review of the condition; senior plant management determined that the prudent course of action was to bring the plant to cold shutdown in a controlled but prompt manner to reduce the potential adverse effects of the chemistry excursion on the plant. The decision to shut down was driven by internal plant chemistry guidelines and the TRM. The directed plant shutdown was performed in accordance with Integrated Plant Operating Instruction (IPOI) 4, "Shutdown," which includes separate sections for a plant shutdown with slow power reduction and for a plant shutdown with a fast power reduction. Plant management elected to utilize the plant shutdown with a fast power reduction to minimize the potential adverse consequences from the chemistry excursion. The IPOI 4 fast power reduction instructions include the initiation of a manual scram which is the typical final action to complete the insertion of all control rods for plant shutdowns at Duane Arnold, even those conducted in accordance with IPOI 4 slow power reduction Section 3.0 "35% Power to Reactor Shutdown." IPOI 4 allows for the sequential steps of the IPOI to be changed based on actual plant conditions. In this case, the Operations Shift Manager (OSM) directed that the non-essential 4160 VAC busses be transferred to a different power supply. The steps the OSM determined to not be applicable were Step 3, "When load line is less than 52%, at 1C04 reduce A and B MG SET SPEED CONTROL to minimum," and Step 5, "If time permits, insert all operable IRMs per OI 878.2." Step 3 was not completed due to the fact that the plant was already less than 52% load line and with the power level that the plant was at, there were no concerns with approaching the exclusion and buffer regions of the power to flow map. The IRM insertion was an optional step as spelled out in the IPOI. Therefore, after completion of the IPOI steps directed by the OSM, the scram was initiated with reactor power below 30%. IPOI 4 is the standard procedure that would be utilized to conduct such a plant shutdown.

The guidance provided in NEI 99-02, Revision 4 clearly supports the March 18, 2007 scram not being considered an unplanned scram. On page 10, lines 11 and 12, the guidance defines an unplanned scram as "*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." The March 18, 2007 scram was clearly part of the normal Duane Arnold shutdown guidance and the scram was initiated in accordance with the Integrated Plant Operating Instruction, (IPOI) 4, "Shutdown." On page 11, line 5, the guidance excludes "scrams that are part of a normal planned operation or evolution." The March 18, 2007 shutdown was clearly a planned evolution that was proactively directed by plant management to minimize any potential adverse affects from the chemistry excursion. On page 11, line 11, the guidance excludes "Scrams that occur as part of the normal sequence of a planned shutdown." As stated above, the March 18, 2007 shutdown was clearly a planned evolution that was proactively directed by plant management to minimize any potential adverse affects from the chemistry excursion. Specifically, the shutdown was driven by the plant's TRM, not by the plant's AOP. The scram would be considered a planned scram, and the event and its effects counted instead within the Unplanned Power Changes indicator. (See NEI 99-02, R4, pages 9 – 11 and 18.)

The NRC Resident does not agree with the Duane Arnold position regarding categorization of the scram as the Resident considers the fast power reduction section of IPOI 4 to be an abnormal section of a normal procedure and therefore concludes the scram should count as unplanned.

<u>Is it the correct interpretation that the above event should not be considered an unplanned scram with respect to the NRC indicator</u>?

Potentially relevant existing FAQ numbers:

Archived guidance FAQ 159 dated 4/1/2000 and FAQ 5 dated 11/11/1999 also support the conclusion that the event would not be considered an unplanned scram with respect to the NRC indicator.

> FAQ 159 Posting Date 4/1/2000
>
> **Question:** With the Unit in Operational Condition 2 (Startup) a shutdown was ordered due to an insufficient number of operable Intermediate Range Monitors (IRM). The reactor was critical at 0% power. "B" and "D" IRM detectors failed, and a plant shutdown was ordered. The manual scram was inserted in accordance with the normal shutdown procedure. Should this count as an unplanned reactor scram?"
>
> **Response:** No. If part of a normal shutdown, (plant was following normal shut down procedure) the scram would not count..

The response to FAQ 159 directly applies to the March 18, 2007 shutdown as the plant was following the normal shutdown procedure, IPOI 4, "Shutdown."

ID: 5 Posting Date 11/11/1999

Question: The Clarifying notes for the Unplanned Scrams per 7000hrs PI state that scrams that are included are: scrams "that resulted from unplanned transients...." And a "scram that is initiated to avoid exceeding a technical specification action statement time limit;" and, scrams that are not included are "scrams that are part of a normal planned operation or evolution" and, scrams "that occur as part of the normal sequence of a planned shutdown..." If a licensee enters an LCO requiring the plant to be in Mode 2 within 7 hours, applies a standing operational procedure for assuring the LCO is met, and a manual scram is executed in accordance with that procedure, is this event counted as an unplanned scram?

Response: If 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 scram would not be counted as an unplanned scram. However, the power reduction would be counted as an unplanned transient (assuming the shutdown resulted in a power change greater than 20%). However, 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.

Although Duane Arnold was not in a Technical Specification LCO (the plant was in a TRM LCO), the shutdown was conducted in accordance with the normal plant shutdown procedure IPOI 4, "Shutdown" and the response to FAQ 5 directly supports the Duane Arnold position.

<u>Response Section</u>

Proposed resolution of FAQ:

The March 18, 2007 shutdown was a planned evolution that was directed by plant management to minimize any potential adverse affects from a chemistry excursion. Specifically, the shutdown was driven by the plant's TRM, not by the plant's Abnormal Operating Procedures. Additionally, the insertion of the manual scram was directed by a normal operating procedure. The shutdown was not an unplanned scram and should not be counted against the Unplanned Scrams per 7000 Critical Hours performance indicator. The event is counted within the Unplanned Power Changes indicator.

Plant: James A. FitzPatrick Nuclear Power Plant
Date of Event: 04/02/07
Submittal Date:
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 Guidance needing interpretation (include page and line citation):

Unplanned Power Changes Per 7,000 Critical Hours, beginning at the bottom of page 17 at line 42 and continuing on to the top of page18 through line 5, 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

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

Event or circumstances requiring guidance interpretation:

During the last week of March increased turbulence in the lake was observed with the passing of storms and melt off of the winter snow pack. On Saturday March 31, 2007 at 2030 Operations noted that the "B" condenser Delta T had risen 13 °F in a three hour period. A condition report (CR-JAF-2007-01273) was entered into the corrective action program. On Sunday April 1, 2007 at approximately 0130 Engineering determined that the observed degradation was consistent with condenser fouling, likely caused by the disturbances on the lake transporting additional marine debris into the condenser water boxes.

On Monday April 2, 2007, after review of the data, the decision was made to perform a downpower of approximately 25% to support cleaning of the B1 and B2 condenser waterboxes, rather than wait until the scheduled May downpower. Power was reduced on April 3, 2007 at 0240.

The cleaning evolution is included in the Circulating Water System Operating Procedure (OP-4). The evolution was evaluated using the online risk model and the impact on the work week was assessed. The plant could have waited an additional 18 hours to meet the 72 hour criteria but chose to make a conservative decision to reduce power and perform water box cleaning.

On May 21, 2007 during the planned downpower the water boxes were opened and cleaned. Based on the engineering analysis of the conditions discovered during the May 2007 cleaning activities we believe that the fouling experienced was attributable to conditions in the lake that were beyond the control of the licensee.

In summary, JAF concludes that the downpower on April 3, 2007 was caused by an environmental problem that could not have been predicted greater than 72 hours in advance, that actions to address the problem had been previously proceduralized and did not require 72 hours to plan, and that the downpower was not performed due to a sudden discovery. The licensee could have waited an additional 18 hours to meet the 72 hour criteria. The down power on April 3, 2007 should not be counted against the performance indicator.

As noted above NEI 99-02 Revision 4, 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

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

This has been reviewed with the Senior Resident and there is no disagreement with regard to the facts as presented.

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.

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

None required.

FAQ 71.5

Plant: Oconee

Submittal Date: 7/10/07

Licensee Contact: Judy Smith Tel/email: 864-885-4309 jesmi@duke-energy.com

NRC Contact: Dan Rich Tel/email: 864-885-3008 dwr1@nrc.gov

Performance Indicator: MS06 MSPI Emergency AC Power System

Site-Specific FAQ (Appendix D)? Yes

FAQ requested to become effective when approved.

Question Section

- Is it acceptable to use the segment approach as described in NEI 99-02, Revision 5, Appendix F, page F-3, line 40, for the Oconee Emergency AC Power System to change from 2 trains to 4 segments?

- Is it acceptable to use plant specific Maintenance Rule data from 2002-2004 to calculate the Unplanned Unavailability Baseline for the Oconee Emergency AC Power System? Oconee is requesting to use the same approach as the cooling water systems, as described in NEI 99-02, Appendix F, page F-10, line 13.

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

NEI 99-02, Revision 5, Appendix F, page F-3, line 12 states "For emergency AC power systems the number of trains is the number of class 1E emergency (diesel, gas turbine, or hydroelectric) generators at the station that are installed to power shutdown loads in the event of a loss of off-site power."

NEI 99-02, Revision 5, Appendix F, page F-10, line 5 – 11 states, "If a front line system is divided into segments rather than trains, the following approach is followed for determining the generic unplanned unavailability:

1. Determine the number of trains used for SSU unavailability reporting that was in use prior to MSPI
2. Multiply the appropriate value from Table 1 by the number of trains determined in (1).
3. Take the result and distribute it among the MSPI segments, such that the sum is equal to (2) for the whole MSPI system."

Table 1 of Appendix F details the Unplanned Unavailability Baseline data based on ROP Industry wide data. To accurately reflect unplanned unavailability of the Oconee Emergency AC Power System, the plant specific data should be used to determine a baseline.

Event or circumstances requiring guidance interpretation:

In the original MSPI Basis Document, the Oconee Emergency AC Power System was identified as two independent, separate trains. This was a simplified, conservative categorization that was chosen to meet the guidance per Appendix F, Page F-3, line 12 for Emergency AC Power Systems.

The Oconee Emergency AC Power System is unique in the fact that it is a hydroelectric system, significantly different in design from other plants which use diesel generators as their Emergency AC Power. Keowee Hydro Station consists of two hydroelectric units which connect to all three Oconee Units. These hydro units are connected to each Oconee unit through an overhead power path, as well as, through an underground power path. The Keowee units are interchangeable and can supply either path, which differs from a normal diesel generator train lineup. This unique arrangement of Keowee (i.e. two independent power paths with two interchangeable power sources) requires the use of a segment approach (as opposed to the two-train approach) to accurately reflect the risk profile of our Emergency Power System. Currently the base PRA model for the Oconee Emergency Power system accounts for the different segments; therefore, no changes need to be made to the base PRA model to incorporate this change.

Redefining the Emergency AC Power System into four segments, i.e. each Keowee unit is a segment and each power path a segment, using the same approach as described for Cooling Water Systems, will more accurately reflect the risk profile of the Oconee Emergency AC Power System.

The N (Normal) breakers are no longer going to be included as monitored components. Also, the FV/UA max will no longer be the FV associated with the N breakers. These changes are due to the fact that the N breaker itself, as well as a failure of the N breaker, is outside the scope of the NEI guidance for Emergency AC power systems.

Licensee and NRC resident/region agree on the facts and circumstances

(Dan Rich to confirm NRC Region 2 agreement)

Potentially relevant existing FAQ numbers N/A

Response Section

Appendix D since this is an Oconee unique issue.

Proposed Resolution of FAQ

In order to remove the unnecessary conservatism in our MSPI model and more accurately depict the Oconee design, Duke proposes to use the four segment approach for the Emergency AC Power System. Each Keowee unit is a segment, and each power path is a segment. The segment approach is described in NEI 99-02, Appendix F, page F-3, line 40, for Cooling Water Systems. Oconee is requesting to use the same approach with its Emergency AC Power System.

Duke also proposes to update Table 1 in NEI 99-02, Appendix F-9, to reflect that the unplanned unavailability baseline data associated with Oconee Emergency AC system is plant specific Maintenance Rule data for 2002-2004, as seen with Cooling Water Systems described in NEI 99-02, Appendix F, page F-10, line 13.