October 1, 2007

MEMORANDUM TO: James W. Andersen, Chief
Performance Assessment Branch
Division of Inspection and Regional Support
Office of Nuclear Reactor Regulation

FROM: Joseph M. Ashcraft, Reactor Operations Engineer ***/RA/***
Performance Assessment Branch
Division of Inspection and Regional Support
Office of Nuclear Reactor Regulation

SUBJECT: PUBLIC MEETING SUMMARY ON THE REACTOR OVERSIGHT PROCESS HELD ON SEPTEMBER 19, 2007

On September 19, 2007, the staff hosted the monthly Reactor Oversight Process (ROP) Working Group public meeting. The attendance list for the meeting is contained in Enclosure 1. The agenda for the meeting is contained in Enclosure 2.

The staff discussed industry concerns regarding the issuance of Regulatory Issue Summary (RIS) 2007-021, "Generic Communication on Adherence to Licensed Power Limits" contained in Enclosure 5, as well as the need for better communications between the ROP Working Group and the Nuclear Energy Institute (NEI) Licensing Action Task Force (LATF). The staff will continue to discuss these topics at the next ROP public meeting in October.

The staff continued discussing ongoing activities related to the revision of the Significant Determination Process (SDP) appeal process, safety culture efforts, and various other ROP topics and will update the working group in future meetings. Additionally, the meeting attendees discussed guidance interpretation issues for current frequently asked questions (FAQs) contained in Enclosure 3, concerning the Mitigating Systems Performance Index (MSPI). A draft MSPI FAQ was introduced by the industry for a proposed guidance change to improve consistency in the guidance and allow flexibility in the timing of Consolidated Data Entry (CDE) entries made to reflect changes in the site MSPI Basis Document.

CONTACT: Joseph Ashcraft, NRR/DIRS/IPAB
301-415-3177

The status of the open draft FAQs are as follows:

TempNo.	PI	Topic	Status	Plant/ Co.
70.0	MSPI	Blown Fuse on Diesel	06/13 Introduced 07/18 Discussed 08/22 Discussed 09/19 Discussed, continue next mtg	Ft. Calhoun
71.0	1E01	Chemistry Excursion	07/18 Introduced and Discussed 08/22 Discussed 09/19 Discussed, continue next mtg	Duane Arnold
71.1	1E03	Environmental Condition Downpower	07/18 Introduced and Discussed. 08/22 Discussed 09/19 Tentative Approval	FitzPatrick
71.5	MS06	Emergency AC Power Modeling	07/18 Introduced and Discussed. 08/22 Tentative Approval 09/19 Final Approval, contingent on implementation	Oconee
72.0	EP03	Siren Activation	08/22 Introduced and Discussed 09/19 Discussed, continue next mtg.	Cook
72.1	MSPI	HPI Trains	08/022 Introduced and Discussed 09/19 Final Approval, contingent on implementation	Turkey Point
73.0	MSPI	Changes to CDE for Basis Document Parameters FAQ	09/19 Introduced, Discussed and Tentative Approval	Generic

FAQs on Appeal:

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

FAQs 70.0 and 71.0 were discussed and both the NRC and Industry Group are reviewing the issues.

There was no consensus on FAQ 72.0. The staff will document their decision in a response to the FAQ.

FAQ 71.1 and 73.0 were tentatively approved. The staff should make final decisions at the October meeting.

FAQ 71.5 and 72.1 were approved, with contingents on implementation. The revised basis input cannot replace the existing quarterly data input format until changes to the Institute of Nuclear Power Operations (INPO) software are made for CDE.

The date for the next meeting of the ROP Working Group is October 18, 2007.

Enclosures:
1. Attendance List
2. Agenda
3. FAQ Log, dated 9/07
4. NEI Action List
5. NEI Discussion of RIS 2007-21

The date for the next meeting of the ROP Working Group is October 18, 2007.

Enclosures:
1. Attendance List
2. Agenda
3. FAQ Log, dated 9/07
4. NEI Action List
5. NEI Discussion of RIS 2007-21

DISTRIBUTION:
PUBLIC

DRoberts	ABoland
AVegel	AHowell
BHolian	CCasto
CPederson	DLew
DChamberlain	HChristensen
ISchoenfeld	JShea
JClifford	KKennedy
THsia	MGamberoni
RCaniano	SWest
VMcCree	DDube
IPAB	PAppignani
IRIB	

Accession Number: ML

OFFICE	DIRS/IPAB	DIRS/IPAB
NAME	JAshcraft	JAndersen
DATE	09/25/07	10/01/07

OFFICIAL RECORD COPY

ATTENDANCE LIST
INDUSTRY/STAFF ROP PUBLIC MEETING

	NAME	AFFILIATION
1	John Butler	NEI
2	Julie Keys	NEI
3	Lenny Sueper	NMC
4	Mike O'Keefe	Florida Power & Light
5	Duane Kanitz	STARS
6	Don Olson	Dominion
7	Robin Ritzman	FENOC
8	Glen Masters	INPO
9	Darla King	Duke
10	Lou Larragoite	Constellation Energy
11	Bryan Ford	Entergy
12	Russell Smith	NEI
13	David Lockaum	Union of Concerned Scientists
14	Roy Lithicum	Exelon
15	Sue Simpson	AEP/DC Cook
16	Jeff Hansen	Exelon
17	Brian McCabe	Progress Energy
18	Mike Schoppman	NEI
19	Jack Stringfellow	SNC
20	Don Olson	Dominion
21	Stuart Richards	NRC
22	Terry Reis	NRC
23	James Andersen	NRC
24	John Thompson	NRC
25	Bob Gramm	NRC
26	Joe Ashcraft	NRC
27	Jesse Robles-Alcaraz	NRC
28	Mary Ann Ashley	NRC
29	Mike Case	NRC
30	Stacy Smith	NRC
31	Martin Murphy	NRC
32	Don Hickman	NRC
33	Jim Kellum	NRC
34	Robert Kahler	NRC
35	Jim O'Driscoll	NRC
36	Eugene Huang	NRC
37	Bob Jickling	NRC

Enclosure 1

ROP WORKING GROUP PUBLIC MEETING AGENDA

September 19, 2007
9:00 a.m. - 4 p.m.
Ramada Inn
Conference Call Line: 800-638-8081
301-231-5539
Pass Code: 5871 Meeting Leader: Joseph M. Ashcraft

Time	Topic	Process	Leader
9:00 - 9:05 a.m.	Introduction and Purpose of Meeting	Discuss	Andersen
9:05 - 10:00 a.m.	**Reactor Inspection Branch Topics** • RIS-2007-21 - Core thermal power (Jordon memo) • Backfit •SDP appeal changes • Other Topics	Discuss, share information.	1. Ashley / Case 2. Murphy / O'Driscoll 3.-4. Reis
10:00 - 10:30 a.m.	**Performance Assessment Branch Topics** 1. Safety Culture status 2. Preliminary Safety Culture Survey Results 3. Other Topics	Discuss, share information	1.Andersen 2.Keys
10:30 - 10:45 a.m.	Break **- Public Input**		
10:45 – 12:00p.m.	**Guidance Interpretation** 1. Kewaunee - appeal 2. Ft. Calhoun 3. DC Cook 4. Duane Arnold 5. FitzPatrick 6. Oconee 7. Turkey Point 8. Generic FAQ (CDE/Basis Document changes)	1. August 2, 07 2.-8. Discuss, gain agreement.	1. Andersen 2.-8. Keys

Enclosure 2

12:00 - 1:00 p.m.	Lunch - **Public Input**		
1:00 - 2:00 p.m.	**Guidance Interpretation (con't)**		All
2:00 - 2:15 p.m.	Break - **Public Input**		
2:15 – 2:30p.m.	**Maintenance Rule alignment with ROP** 1. NEI 93-01	1. Status	1.Alexander
2:30 - 3:00 p.m.	**Future Agenda** 1. Future Meeting Dates 10/18 12/05 (Nov/Dec) 01/17/08 (tentative) 02/21/08 (tentative)	1.Select	1. Andersen
	2. Action Item Review White paper (future) - Inspector's abuse of FAQ process - unplanned unavailability - treatment of operator errors	2. Review	2. Keys
	3. Future Topics	3. Decide	3. All
	4. Meeting Critique	4. Discuss	4. All
3:00 - 3:15 p.m.	Adjourn - **Public Input**		

Enclosure 2

FAQ LOG 09/07

TempNo.	PI	Topic	Status	Plant/ Co.
70.0	MSPI	Blown Fuse on Diesel	06/13 Introduced 07/18 Discussed 08/22 Discussed	Ft. Calhoun
71.0	1E01	Chemistry Excursion	07/18 Introduced and Discussed 08/22 Discussed	Duane Arnold
71.1	1E03	Environmental Condition Downpower	07/18 Introduced and Discussed. 08/22 Discussed	FitzPatrick
71.5	MS06	Emergency AC Power Modeling	07/18 Introduced and Discussed. 08/22 Tentative Approval	Oconee
72.0	EP03	Siren Activation	08/22 Introduced and Discussed	Cook
72.1	MSPI	HPI Trains	08/022 Introduced and Discussed	Turkey Point
73.0	MSPI	Changes to CDE for Basis Document Parameters FAQ	09/19 Introduced and Discussed	Generic

FAQs on Appeal:

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

FAQ 70.0
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

Issue #1:

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 OPERABLE is also considered to be available."*

...and the licensee further references page F-5, lines 34-40, stating ...*"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."*

As described in NRC Inspection Report 05000285/2005010, Emergency Diesel Generator #1 was both inoperable and unavailable 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.

Issue #2:

In the licensee's FAQ, the licensee stated on page 2, *"... the control room staff received numerous expected alarms."* and then went on to say *"These expected plant computer alarms were received within moments of when they normally would have occurred."* 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."

Issue #3:

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, it was determined that it would have been unreasonable to expect the control room staff to have caught this when it occurred."* 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

Fort Calhoun Station June 2007 FAQ
Attachment 2

FAQ 71.0
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.

<u>Question Section</u>

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 **<u>are not</u>** 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 **<u>are not</u>** 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.

Response Section

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.

FAQ 71.1

Plant:	James A. FitzPatrick Nuclear Power Plant		
Date of Event:	04/02/07		
Submittal Date:			
Licensee Contact:	Gene Dorman	**Tel/email:**	(315) 349-6810/ edorman@entergy.com
Licensee Contact:	Jim Costedio	**Tel/email:**	(315) 349-6358/ jcosted@entergy.com
NRC Contact:	Gordon Hunegs	**Tel/email:**	(315) 349-6667/gkh@nrc.gov

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

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

FAQ requested to become effective when approved.

<u>Question Section:</u>

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

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

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

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

Event or circumstances requiring guidance interpretation:

On March 2, 2007 the Operations Department initiated a condition report (CR-JAF-2007-00841) identifying that the differential temperature across the B1 waterbox had risen approximately 9°F since the February 6, 2007 defish evolution, and that higher water box differential pressure on the B2 waterbox and rising backpressure in the "B" condenser indicated that there was some fouling of the waterboxes. It is notable that configuration of the supply piping to the waterboxes causes the B1 Waterbox to more readily collect debris than the others. On March16, 2007 Engineering notified Planning and Scheduling that the waterboxes would have to be cleaned to restore performance. Based on the parameters (waterbox Delta T, Delta P, Condenser Backpressure, CWS flow, and CWS Pump amps) and available trend information it was determined that the cleaning could be performed during a scheduled May 2007 Downpower and On-Line Emergent Work Addition Approval Form EN-WM-101 was submitted to add Work Order 51102525 to the downpower schedule.

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. When the condition of the lake was identified the traveling screens were placed in continuous operation. While continuous operation of the screens is effective in removing large material, the screens are not fine enough to prevent the entry of smaller debris such as zebra mussel shells. On Saturday March 31, 2007 at 2030, Operations noted that the "B" condenser Delta T had risen 13 °F in a three hour period. Review of historical trend information showed the plant has never experienced such a rapid change in condenser Delta-T. 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. Temperatures and pressures stabilized such that no operational limits were exceeded.

On Monday April 2, 2007, after review of the data, the decision was made to perform a downpower of approximately 25% to support defishing 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 defishing 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. Since the plant parameters were stable and within operational limits 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 defish. The defishing evolution was conducted using the same procedures and guidance used during the February defishing evolution.

In summary, JAF believes 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 downpower on April 3, 2007 should not be counted against the performance indicator.

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

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

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

<u>Response Section:</u>

Proposed Resolution of FAQ:

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

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

None required.

FAQ 71.5
Plant: Oconee Nuclear Station

Submittal Date: 07/10/07

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 two trains to four 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 through 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 that it is a hydroelectric system, significantly different in design from other plants which use diesel generators as the 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 the 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 segments, 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 Unplanned Unavailability Baseline for Emergency AC Power using 2002-2004 Maintenance Rule data for the segment approach is comparable to the Unplanned Unavailability Baseline of the diesels, with the new Oconee Emergency AC Power baseline being slightly more conservative than that of the diesel baseline when using the segment approach.

Oconee Technical Specifications allow both emergency power supplies (Keowee Hydro Unit 1 and 2) to be out of service concurrently, i.e. a "dual unit outage," for up to 60 hours for planned maintenance, a feature unique to Oconee. Also, per Technical Specifications, the planned removal of both emergency power sources is contingent on having the standby buses energized from Lee combustion turbines through a dedicated power path. This configuration is explicitly modeled in the Oconee PRA for planned dual-unit outages.

The planned unavailability baseline for Emergency AC power includes hours for the planned dual-unit outages which occur on a regular cycle. Any additional planned dual-unit outages necessary to fix equipment issues within the current MSPI quarter will not be included in the baseline. Planned unavailable time during dual unit outages is accrued on any train/segment that is affected by the dual unit outage, causing multiple trains/segments to count unavailable time during the dual-unit outage. Oconee's approach for the Emergency AC Power segments uses PRA basic events that do not credit the standby bus being energized (prior to an initiating event) which results in Birnbaum values that are higher than those associated with an actual planned dual-unit outage.

Therefore, although the Oconee emergency power system has planned dual-unit outages allowed by its Technical Specifications, the risk profile is conservatively reflected and adequately captured in MSPI due to counting unavailability time on multiple trains/segments and applying higher risk importance values.

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, Walt Rogers, and Don Dube reviewed this FAQ and agreed with the proposed approach contained within the FAQ.

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 the Oconee 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.

FAQ 72.0
Plant: Donald C. Cook Nuclear Plant (CNP)
Date(s) of Event(s): May 5, 2007
Submittal Date: August 10, 2007
Licensee Contact: Sue Simpson Tel/email: 269-466-2428,sdsimpson@aep.com
NRC Contact: Eric Duncan Tel/email: 630-829-9757, erd@nrc.gov

Performance Indicator

EP03 Alert and Notifications System (ANS) Reliability

Site-Specific FAQ (Appendix D)?

YES

It is requested that this FAQ becomes effective upon approval.

Question Section

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

Alert and Notification System Reliability, Page 58, lines 30-35.

This paragraph discusses multiple control stations or signals and focuses on whether those provisions are within approved procedures. If the use of redundant control stations or multiple signals is in approved procedures and is part of the actual system activation process, then activation from either control station or any signal should be considered a success.

Event or circumstances requiring guidance interpretation:

Siren Testing Procedure

In order to fully understand the actions taken during the May 5, 2007, scheduled siren test, it is important to understand the content of the 911 dispatch center guidance. The 911 dispatchers are provided guidance in the *Berrien County Early Warning Siren System (EWS) Operation Manual* (approved procedure). Dispatchers are also provided with initial and continuing (nominally annual) training. Written direction within the procedure directs the dispatchers to contact specific telecommunications technicians if an unexpected or abnormal condition with the siren system is detected at any time. The telecommunications technician provides direction to the dispatcher. Based on indications, the telecommunications technician may provide direction to repeat the siren activation process; this response is covered during the siren system activation training. Siren system activation training is given by the telecommunications technician. Each dispatcher is individually tested on the equipment. Based on the approved procedure, training, and qualification, the dispatcher followed the siren testing procedure in the events described below. In addition, when this issue was discussed with FEMA, they concurred that the county stayed within the FEMA approved siren testing procedure.

May 5, 2007, Siren Testing

On May 5, 2007, at 1300 hours, during the routine siren testing of the CNP alert and notification system (ANS), the initial attempt to actuate the sirens did not achieve the anticipated results (none of the 69 sirens being tested received an actuation signal). Siren testing is performed by Berrien County personnel located in the local 911 dispatch center (Primary Activation Center). An electronic map board is located within the facility and provides indication when a siren is actuated. The dispatcher did not get the expected response after the first attempt, i.e., the map board did not show any sirens were actuated. During the test, the dispatcher was in telephone communication with the telecommunications technician responsible for siren testing and maintenance since this was the dispatcher's first testing opportunity after completion of training. As provided for by siren testing procedure, the dispatcher informed the telecommunications technician that she did not get the expected response upon the first activation. Also in accordance with the established siren testing procedure, the telecommunications technician directed the dispatcher to re-perform the test sequence. A total of five attempts were made over an eight minute period (specifically, the initial attempt at 1300 hours plus four additional attempts). Note that a simultaneous transmission on a media frequency which occurs concurrently with the siren actuation transmission did occur with each actuation attempt as expected. The telecommunications technician drove to the Backup Activation Center to verify indication on the map board at that location. When he confirmed that indication at the Backup Activation Center was identical to the 911 dispatch center, the telecommunications technician directed the dispatcher to initiate another siren activation attempt. The sirens responded as expected on this attempt (six) at approximately 1323 hours.

Note that the CNP siren system consists of 70 sirens total. On May 5, 2007, only 69 sirens were tested. The county had tested the other siren on May 4, 2007, due to community activities (parade).

No maintenance was performed between the initial scheduled attempt and the successful attempt. The apparent cause of this event was determined to be an intermittent dead spot on a potentiometer associated with the siren activation circuitry. No indications of equipment failure or malfunction could be identified on May 5, 2007, after the successful siren test. However, on May 26, 2007, a lightning strike at the primary activation center caused the failure of the 155.925 MHz receiver, causing the encoding equipment to operate abnormally. During the post-maintenance testing after replacement of the affected equipment, the telecommunications technicians saw indications that duplicated the siren response on May 5. Since they were present in the affected facility, they were able to trace the problem to a potentiometer on the microphone input board. The potentiometer was "wiped" and the problem could not be repeated. The telecommunications technicians noted that an intermittent failure on this type of device is not unusual. A new potentiometer was installed.

<u>Conclusion – Siren Testing was Successful</u>

The ANS Reliability PI reports the percentage of ANS sirens that are capable of performing their function as measured by periodic siren testing in the previous 12 months. The only performance criterion is successful completion of a siren test. The guidance does not specify how a test is to be performed, i.e., the specific steps of a test are not prescribed. FEMA reviews the siren testing procedures. As long as the dispatcher follows the guidance to perform the siren test and the test is not exited for maintenance or other corrective actions, then activation of the sirens within the bounds of the guidance using multiple signals is a success. This interpretation is supported by the response in Archived FAQ 232.

The NRC has indicted that they believe the May 5, 2007, siren test was a failure solely based on the amount of time required to activate the siren during the test sequence. CNP's position is that time is not a factor in the performance indicator. CNP's position is supported by FEMA's statements in the Federal Register, Volume 67, Number 80, dated April 25, 2002. FEMA has recognized that initiation of the ANS needs to be done in a "timely manner" following notification to the offsite response organization by the nuclear power plant. Their position is that decision makers are tasked with the responsibility to use judgment based on the conditions or scenario. Therefore, they have not established a firm time for ANS activation after notification.

The NRC's position is based on a 10 CFR 50 Appendix E, design objective of ***about*** (emphasis added) 15 minutes for siren activation. This design objective has never been part of the PI guidance for a successful siren test. The PI guidance definition of a successful siren test does not include a time-related performance criterion. The NRC is attempting to add a new criterion to the definition of successful siren tests by imposing the Part 50, Appendix E design objective. The design objective may be subject to inspection but is not a factor in PI reporting.

Accepting NRC's position that the May 5, 2007, siren test was a failure would inappropriately lead to a Yellow PI for CNP. The Yellow performance band shows a decline in licensee performance that is still acceptable with cornerstone objectives met, but represents a significant reduction in safety margin. CNP's siren performance has not experienced a significant reduction in safety margin. In fact, the CNP ANS is healthy as evidenced by routine polling data and sustained previous performance. The delay in activation of this one test should not be allowed to skew CNP's performance. The method of calculation varies among licensees; some licensees include polling in their testing procedure; others include "growl" tests; still others only activate sirens the minimum of one time per year. When the denominator is small (based on approved testing), small changes in the numerator can drive performance from the Green band to the unacceptable Yellow performance band. Such significant changes in Performance Indicators should be based on actual performance and not disparate calculation methods. CNP uses monthly testing of 70 sirens for the PI calculation. While CNP still believes the test was successful, if the siren test is considered a failure, CNP moves from Green to Yellow (Column 3). CNP station performance is not Column 3, and a 95002 inspection is not warranted based on this one incident.

Question: Multiple activation signals were sent to all sirens being tested. The sirens did not initially appear to respond. Additional attempts to actuate the sirens were made in accordance with existing guidance. On the sixth attempt, all sirens being tested successfully activated. Can this be considered a successful test of the siren system?

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

NRC Region III staff believes that the siren test was a failure based on the siren design objective found in 10 CFR 50 Appendix E, Section IV D, paragraph 3, "…The design objective of the prompt public notification system shall be to have the capability to essentially complete the initial notification of the public within the plume exposure pathway EPZ within about 15 minutes…." They have indicated general agreement with CNP's decision to request resolution of the above question using the FAQ process.

Potentially relevant existing FAQ numbers

Archived FAQ 232, question 2.

2) A siren test technician sent multiple activation signals to a siren that initially appeared not to respond. The siren responded. Can the multiple signals be considered as the regularly scheduled test and hence a success?

Response

2) Yes, if the use of multiple signals is in approved procedures and part of the actual system activation process. However, the use of multiple activation signals to achieve successful siren tests may not include any activities outside the regularly scheduled test, such as troubleshooting, post maintenance testing or activation signals sent after the initial activation process has ended.

<u>**Response Section**</u>

Proposed Resolution of FAQ

The siren testing evolution conducted by CNP on May 5, 2007, from 1300 hours to 1323 hours, which concluded with all sirens actuating as designed, should be considered a successful test.

The siren test was consistent with the guidance contained in NEI 99-02, Regulatory Assessment Performance Indicator Guideline, Section 2.4, Emergency Preparedness Cornerstone, Page 58 Lines 30 though 35, specifically the use of multiple signals to obtain a successful siren activation test. Consistent with the response to FAQ 232,

- Successful activation of sirens was accomplished during the regularly scheduled siren test
- No activities such as maintenance or troubleshooting were done during the regularly scheduled siren test
- Successful siren activation was completed within the initial activation process as directed by the siren testing procedure

Testing under these conditions is considered a single valid attempt with a successful outcome. CNP should remain in the Green performance band.

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

Not applicable

FAQ

FAQ 72.1

Plant: Turkey Point

Date of Event: NA

Submittal Date: 6/18/07

Licensee Contact: Ching Guey Tel/email: 561-694-3137 / ching_guey@fpl.com

Mark Averett Tel/email: 561-694-3857 / mark_averett@fpl.com

NRC Contact: Scott Stewart Tel/email: 305-246-6199 / james_s_stewart@fpl.com

Walt Rogers Tel/email: 404-562-4619 / wgr1@nrc.gov

Performance Indicator: MSPI

Site-Specific FAQ (Appendix D)? Yes

FAQ requested to become effective when approved and implemented once the appropriate changes are made to CDE.

Question Section

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

Page F-48, Section F.5, lines 45-46, and page F-49, Section F.5, lines 1-7 of the NEI 99-02, Appendix F guidance describes train determination for three-loop Westinghouse plants; however, the system described therein does not represent the HHSI system at Turkey Point. Therefore, there is no system-specific guidance for HHSI which is applicable to the HHSI system at Turkey Point.

Event or circumstances requiring guidance interpretation:

During the week of June 4-8, 2007, an audit of the PTN MSPI programs was conducted. During his review of the PTN MSPI Basis Document proposed update, the technical expert brought in for the audit noted the uniqueness of Turkey Point's HHSI system in that both the Unit 3 and Unit 4 HHSI pumps start on an SI signal from either unit, and all of them feed the stricken unit. He also noted that the generic CCF factors for Turkey Point (NEI 99-02, Table 3) imply that there are 4 pumps being monitored for each unit. The NEI 99-02 guidance for Westinghouse 3-loop plants (pages F-48 and 49), which states that 3-loop plants have 3 pumps, one of which is an installed spare, does not apply for the Turkey Point 3-loop configuration.

For reliability monitoring, the two Unit 3 HHSI pumps are monitored for Unit 3, and the two Unit 4 HHSI pumps are monitored for Unit 4. For unavailability monitoring, the two Unit 3 HHSI pump trains and the two Unit 3 discharge valves are monitored for Unit 3, and similarly, the two Unit 4 HHSI pump trains and two Unit 4 discharge valves are monitored for Unit 4. The opposite-unit pump trains are not monitored for unavailability for either unit. The technical expert for the audit recommended that the opposite-unit HHSI pumps be added for unavailability and reliability monitoring.

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

The NRC resident inspector, Scott Stewart, and the Region II SRA, Walt Rogers do not have disagreements with the facts and circumstances as described above.

Potentially relevant existing FAQ numbers:

NA

Response Section

Proposed Resolution of FAQ:

FPL proposes to add the opposite-unit HHSI pump trains for unavailability monitoring for each unit, and the opposite-unit HHSI pumps for reliability monitoring for each unit. Although the opposite-unit HHSI pumps are cooled by the opposite-unit component cooling water (CCW) pumps, it is proposed that they not be added as they are already monitored for their associated unit, and their Birnbaum importances for the opposite-unit are several orders of magnitude less than their Birnbaum importances for their own unit.

Revise NEI 99-02, Appendix D to include the Turkey Point HHSI configuration. The current guidance for three-loop Westinghouse plants in Appendix F does not apply to Turkey Point.

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

Issue: The Turkey Point High Head Safety Injection (HHSI) design is different than the description provided in Appendix F for Train Determination. Therefore, there is no system-specific guidance for HHSI which is applicable to the HHSI system at Turkey Point.
At Turkey Point, each unit (Unit 3 and Unit 4) has two HHSI pumps. The Unit 3 and Unit 4 HHSI pumps start on an SI signal from either unit, and all of them feed the stricken unit. Should the Turkey Point reporting model be revised to address the four train approach?

Resolution: Yes. In order to ensure accurate reporting, add the opposite-unit HHSI pump trains for unavailability monitoring for each unit, and the opposite-unit HHSI pumps for reliability monitoring for each unit. Although the opposite-unit HHSI pumps are cooled by the opposite-unit component cooling water (CCW) pumps, they should not be added as they are already monitored for their associated unit, and their Birnbaum importances for the opposite-unit are several orders of magnitude less than their Birnbaum importances for their own unit.

Supporting Information:

1. P&ID

PTN-ENG-SEYS-06-028
Revision 1
Page 26 of 197

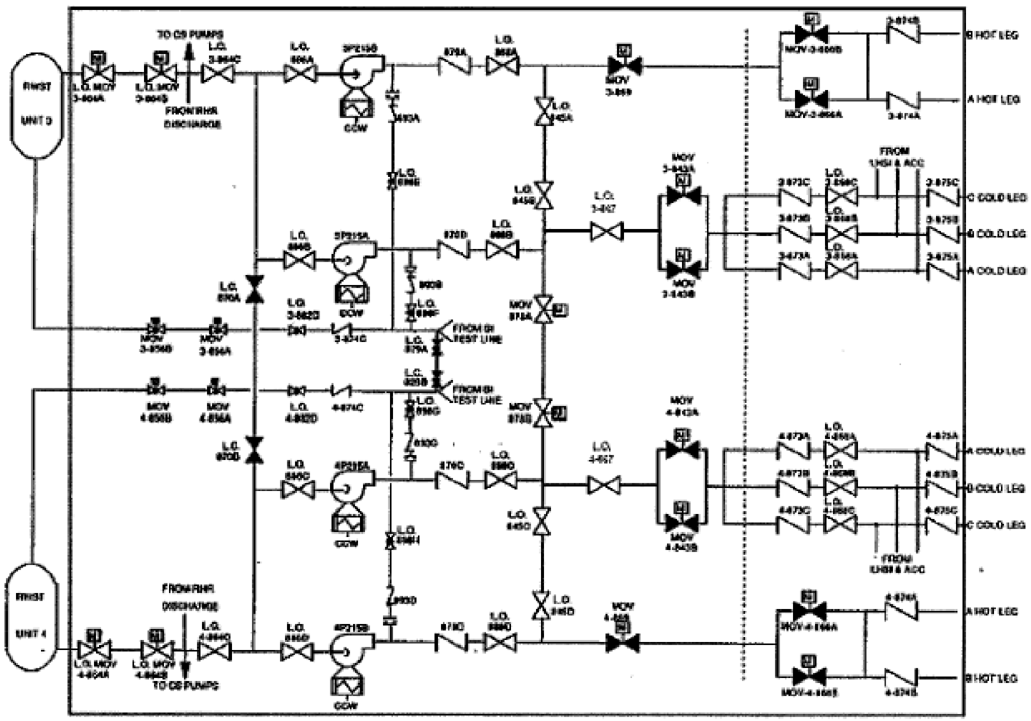

Figure 2.2-1 High Head Safety Injection System

2. System Description

The High Head Safety Injection (HHSI) system injects borated water into the Reactor Coolant System (RCS) to flood and cool the core following a Loss of Coolant Accident (LOCA), thus preventing a significant amount of cladding failure, along with subsequent release of fission products into containment. The HHSI System also, in conjunction with the pressurizer PORVs, provides bleed-and-feed cooling for decay heat removal in the event all feedwater is lost.

There are four safety injection pumps shared between both units. All 4 HHSI pumps (two for Unit 3 and two for Unit 4) start on an SI signal from either unit. All 4 pumps feed into a common header and provide flow to the affected unit via the affected unit's discharge valves into the cold leg piping of the Reactor Coolant System (RCS). Later, if the affected unit's HHSI pumps are determined to be running, the opposite unit's HHSI pumps are stopped. Once the affected unit's RWST inventory is depleted, recirculation of water from the containment sump is required and performed manually. During the recirculation phase, the HHSI System is available to take suction from the discharge of the Low Head Safety Injection/Reactor Heat Removal (LHSI/RHR) pumps and injects into either the RCS Hot Legs (Hot-Leg Recirculation) or Cold Legs (Cold-Leg Recirculation). Cold-leg recirculation using the HHSI pumps is required if recirculation flow to the core, utilizing only the LHSI/RHR pumps, cannot be established because RCS pressure remains above LHSI/RHR pump shutoff head (e.g., for SBLOCAs). Long-term recirculation consists of alternating between injection through the cold and hot legs every 12 hours following the design basis accident. If cold-leg recirculation cannot be established, injection can continue using the opposite unit's RWST as a source of suction for the running HHSI pumps.

Proposed MSPI Guidance Change
Changes to CDE for Basis Document Parameters FAQ

FAQ 73.0
Plant: Generic
Date of Event: N/A
Submittal Date: September 18, 2007
Licensee Contact:Julie Keys Tel/email: 202.739.8128/jyk@nei.org
NRC Contact: Joe Ashcraft Tel: 301.415.3177

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):

This FAQ proposes a guidance change to improve consistency of the guidance and allow flexibility in the timing of CDE entries made to reflect changes in site MSPI basis documents.

The current MSPI guidance (NEI 99-02, Rev 5) states the following regarding changes to baseline information:

Page 30, lines 35-40 and Page 31, lines 1-12 (regarding changes to PRA parameters): The MSPI calculation uses coefficients that are developed from plant specific PRAs. The PRA used to develop these coefficients should reasonably reflect the as-built, as-operated configuration of each plant. Updates to the MSPI coefficients developed from the plant specific PRA will be made as soon as practical following an update to the plant specific PRA. The revised coefficients will be used in the MSPI calculation the quarter following the update. Thus, the PRA coefficients in use at the beginning of a quarter will remain in effect for the remainder of that quarter. Changes to the CDE database and MSPI basis document that are necessary to reflect changes to the plant specific PRA of record should be incorporated as soon as practical but need not be completed prior to the start of the reporting quarter in which they become effective. The quarterly data submittal should include a comment that provides a summary of any changes to the MSPI coefficients. Any PRA model changes will take effect the following quarter (model changes include error, corrections, updates, etc.)

For example, if a plant's PRA model of record is approved on September 29 (3rd quarter), MSPI coefficients based on that model of record should be used for the 4th quarter. The calculation of the new coefficients should be completed (including a revision of the MSPI basis document if required by the plant specific processes) and input to CDE prior to reporting the 4th quarter's data (i.e., completed by January 21).

Page F-8, line 44 and following to Page F-9, line 3 (regarding changes to baseline planned unavailability):
The baseline planned unavailability should be revised as necessary during the quarter prior to the planned maintenance evolution and then removed after twelve quarters. A

comment should be placed in the comment field of the quarterly report to identify a substantial change in planned unavailability. The baseline value of planned unavailability is changed at the discretion of the licensee. Revised values will be used in the calculation the quarter following their update.

Page F-23, lines 38-40 (regarding changes in estimates of demands):
The new estimates will be used in the calculation the quarter following the input of the updated estimates into CDE.

Event or circumstances requiring guidance interpretation:
The concern is that the guidance is unnecessarily restrictive regarding CDE entry for changes in baseline planned unavailability and estimated demands, especially when compared to the guidance for PRA model changes. If a plant makes a change to its basis document for baseline planned unavailability or estimated demands, these values should not be used until the quarter following the change. However, sites should be allowed the flexibility to enter these changes into CDE during the data submittal period at the beginning of the new quarter following basis document revision. This allows the site time to make the entry into CDE. The site basis document can be easily audited to ensure that the change was approved prior to the beginning of the new quarter.

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

This issue was discussed with NRC at the 8/22/07 ROP TF meeting and agreed that it should be moved forward as an FAQ.

Potentially relevant existing FAQ numbers

None

Response *Section*

Proposed Resolution of FAQ

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

Plant Specific PRA **(Page 30, line 35 – Page 31, line 12)**

The MSPI calculation uses coefficients that are developed from plant specific PRAs. The PRA used to develop these coefficients should reasonably reflect the as-built, as-operated configuration of each plant.

Specific requirements appropriate for this PRA application are defined in Appendix G. Any questions related to the interpretation of these requirements, the use of alternate methods to meet the requirements or the conformance of a plant specific PRA to these requirements will be arbitrated by an Industry/NRC expert panel. If the panel determines that a plant specific PRA does not meet the requirements of Appendix G such that the MSPI would be adversely affected, an appropriate remedy will be determined by the licensee and approved by the panel. The decisions of this panel will be binding.

Clarifying Notes **(Page 32, lines 4-8)**

Documentation and Changes

Each licensee will have the system boundaries, monitored components, and monitored functions and success criteria which differ from design basis readily available for NRC inspection on site. Design basis criteria do not need to be separately documented. Additionally, plant-specific information used in Appendix F should also be readily available for inspection. An acceptable format, listing the minimum required information, is provided in Appendix G**.**

Changes to the site PRA of record, the site basis document, and the CDE database should be made in accordance with the following.

Changes to PRA coefficients. Updates to the MSPI coefficients developed from the plant specific PRA will be made as soon as practical following an update to the plant specific PRA. The revised coefficients will be used in the MSPI calculation the quarter following the update. Thus, the PRA coefficients in use at the beginning of a quarter will remain in effect for the remainder of that quarter. Changes to the CDE database and MSPI basis document that are necessary to reflect changes to the plant specific PRA of record should be incorporated as soon as practical but need not be completed prior to the start of the reporting quarter in which they become effective. The quarterly data submittal should include a comment that provides a summary of any changes to the MSPI coefficients. Any PRA model changes will take effect the following quarter (model changes include error, corrections, updates, etc.). For example, if a plant's PRA model of record is approved on September 29 (3rd quarter), MSPI coefficients based on that model of record should be used for the 4th quarter. The calculation of the new coefficients should be completed (including a revision of the MSPI basis document if required by the plant specific processes) and input to CDE prior to reporting the 4th quarter's data (i.e., completed by January 21).
Changes to non-PRA information. Updates to information that is not directly obtained from the PRA (e.g., unavailability baseline data, estimated demands/run hours) will become effective in the quarter following an approved revision to the site MSPI basis document. Changes to the CDE database that are necessary to reflect changes to the site basis document should be incorporated as soon as practical but need not be completed prior to the start of the reporting quarter in which they become effective. The quarterly data submittal should include a comment that provides a summary of any changes to the basis document.

SECTION F 1.2.2 *(PAGE F-8, LINE 44 THROUGH PAGE F-9, LINE 3)*

The initial baseline planned unavailability is based on actual plant-specific values for the period 2002 through 2004. (Plant specific values of the most recent data are used so that the indicator accurately reflects deviation from expected planned maintenance.) These values are expected to change if the plant maintenance philosophy is substantially changed with respect to on-line maintenance or preventive maintenance. In these cases, the planned unavailability baseline value should be adjusted to reflect the current maintenance practices, including low frequency maintenance evolutions.

Some significant maintenance evolutions, such as EDG overhauls, are performed at an interval greater than the three year monitoring period (5 or 10 year intervals). The baseline planned unavailability should be revised as necessary in the basis document during the quarter prior to the planned maintenance evolution and then removed after twelve quarters. A comment should be placed in the comment field of the quarterly report to identify a substantial change in planned unavailability. The baseline value of planned unavailability is changed at the discretion of the licensee. Revised values will be used in the calculation the quarter following the basis document revision.

REACTOR OVERSIGHT PROCESS
ROP Working Group Action List – Status September 2007

Action Item	Description	Task	Responsible Org/Individual	Target Date
06-01	**Unavailability**			
	Issue: The issue of planned vs. unplanned unavailability continues to result in confusion and continuous discussion.	Industry to develop and present for NRC discussion proposed recommendations to fix unavailability indicator	NEI ROPTF	**TBD**
	Status: *8/07: Hold for NRC research projection completion*			
06-05	**RCS Leakage**			
	Issue: BWR & PWR Owners Groups to develop standard methodology for measuring leak rate.	BWR & PWR Owners Groups to develop standard methodology for measuring leak rate.	NRC	**Sept 2007**
	Status: *on hold*			
06-12	**EDG White Paper** Issue: PWR Owners Group Request	Revisit EDG max mission time to use a weighted avg. time.	NEI ROPTF Roy Linthicum	**Oct 2007**
	Status: Involve Don Dube and Gerry Sowers at the appropriate time. 05/07: Still reviewing data. 07/07: This item linked with Survey results. Will review results and determine if further action is needed. 08/07 Survey confirmed there is an issue. Roy to work.			
07-01	**MSPI Data Collection** Issue: Discuss ways to make MSPI data collection more efficient		NEI ROPTF	**Oct 2007**
	Status: Finalize review and present in Oct.			
07-05	**MR Approval** Obtain NRC Approval of NEI 93-01 letter to align Maint. Rule with ROP.		NRC Steve Alexander	**Sept 2007**
	Status: 04/07: Letter issued 05/07: NEI to Follow up for approval status. 07/07: NRC to attend Aug meeting and give an			

Action Item	Description	Task	Responsible Org/Individual	Target Date
	update. 08/07: Update received NRC to formally respond within 30 days with suggestions for additional changes.			
07-08	**EP03 Clarification** Clarify EP03 acceptance criteria		NEI ROPTF	**Oct 2007**
	Status: Draft sent to industry. Will coordinate with NRC once EP has weighed in			

Enclosure 4

NEI Discussion of "Summary of Issue" section in RIS 2007-21
(Adherence to Licensed Power Limits, August 23, 2007)

Licensees are reminded that there is no existing regulatory guidance condoning or authorizing operation of any nuclear power plant in excess of the maximum power level specified in the facility's operating license. While recognizing that thermal power may rise slightly due to normal changes in plant parameters, operators are expected to take prompt corrective action to reduce thermal power whenever it is discovered to be above the licensed limit. Licensees may not intentionally operate or authorize operation above the maximum power level as specified in the license.

First Sentence:
Licensees are reminded that there is no existing regulatory guidance condoning or authorizing operation of any nuclear power plant in excess of the maximum power level specified in the facility's operating license.

NRC has communicated that the primary intent of the RIS was to communicate to licensees that intentional operation in excess of the maximum power level is not allowed. The topic arose in response to documented instances where licensees, citing the 1980 "Jordan memo," proceduralized steps that would allow short periods of operation above the maximum thermal power specified in the plant Technical Specifications. The RIS also communicates that the Jordan memo was only intended as guidance to inspectors on how to address unintentional operation in excess of the maximum power level.

An additional position communicated by the RIS was that the staff had determined that the 1980 enforcement guidance provided by the Jordan memo was no longer needed and was "superseded." The RIS states that the existing Reactor Oversight Process (ROP) contains the appropriate guidance for screening and dispositioning performance issues related to exceeding the licensed power level for a reactor. [Page 2, last paragraph of the Background section]

While intended as enforcement guidance for NRC inspectors, the "Jordan memo" was widely and, for the most part, appropriately used by licensees for the purposes of both operation and reporting to address situations in which the plant unintentionally operated slightly above the licensed thermal power limit due to normal fluctuations around the nominal full power output The memo's value, in terms of the stability it provided to the regulatory process, should not be discounted.

Since 1999, the ROP process has been used to address approximately 1 dozen instances where maximum power level was exceeded. Unstated, however, is the role served by the Jordan memo in determining whether a performance deficiency existed in the innumerable instances since 1980 where the plant licensed thermal power limit was marginally exceeded. The memo assisted both inspectors and plant operators by defining the conditions under which inadvertent operation above licensed thermal power would be considered as a performance deficiency. Most plants have established, through plant procedures and operator instructions, guidance that is conservative with respect to the "Jordan memo" and, at the same time, recognizes that normal fluctuations about a mean power level are expected.

There is currently no replacement guidance that can be used by inspectors or licensees. The void left by the retraction of the Jordan memo has left open a number of questions related to how licensees should operate their plants at the licensed power limit and whether their current operating procedures and operator guidance are appropriate.

Second Sentence:
While recognizing that thermal power may rise slightly due to normal changes in plant parameters, operators are expected to take prompt corrective action to reduce thermal power whenever it is discovered to be above the licensed limit.

The intent of this statement seems clear. In practice, however, it is problematic. Thermal power is not a static and absolute value. It is calculated from a number of plant parameters that, by nature, vary or oscillate. Thermal power is also monitored and controlled in a number of ways. These ways range from instantaneous readings to any of a series of average power calculations (1 hour average, 8 hour average).

Licensees endeavor to operate as close to the licensed power limit as possible. While operating close to the power limit, the oscillations described above naturally result in instantaneous readings above the limit (and others below the limit). On average, the power is controlled below the licensed power limit.

In its extreme, the statement directing prompt action to reduce power whenever it is discovered to be above the licensed limit could be interpreted to mean that actions should be taken in response to any instantaneous power reading above the limit. Hopefully all will agree that this is not the intent. This of course raises the question as to which reading of thermal power is appropriate (10 minute average, 1 hour average, ….?).

Questions are also raised regarding “prompt corrective action”. Does prompt corrective action need to be taken in instances where power measured over short durations slightly exceeds maximum power level but over longer term averages is below the limit? How prompt is “prompt”?

Questions related to power level averages and “prompt corrective action” are the types of questions that the Jordan memo answered. The retraction of this guidance has forced many long accepted practices to be reevaluated with the very real consequence of introducing unintended consequences.

One plant recently ran several overpower scenarios on their simulator requiring the crews to rapidly ramp down to bring power back below 100%. They saw that crews were most successful in mitigating the transient when they ramped at ~ 5 MW/min. The crews that ramped at higher rates found that it introduced additional transients into the secondary, making it more difficult to monitor power and stabilize the plant. The crews who ramped at 15-20 MW/min ended up taking as long to stabilize the plant below 100% as those who ramped at 5 MW/min because of the self induced transients. This points to a concern that a strict interpretation of “prompt corrective action” would, in some cases, be counter to safety.

One PWR with an integrated power control system reports that operators set the max licensed power into the system and the system automatically maintains that power level. When reactor power goes slightly above the setpoint, the control system automatically responds by bringing it back down to the established setpoint (licensed power level). Thus, on occasion, the plant slightly exceeds max power but the system automatically responds and brings power down. In this automatic mode of operation power never exceeds licensed thermal power when averaged over an hourly or 8 hour period. So, essentially, the operators don't do anything to "promptly" bring power down, the system does it automatically. The plant operator has concluded that this automatic system response meets the intent of the RIS with respect to prompt operator action. However, there is a concern that down the road, an inspector may conclude differently.

Most plants operate in a similar manner with power set at max licensed power. Power is stable, but power readings will fluctuate above and below that power level. Procedural guidance, consistent with the “Jordan memo”, directs the operators to monitor and take action to ensure that power does not exceed licensed thermal power when averaged over an hourly or 8 hour period. The language of the RIS, combined with the retraction of the “Jordan memo” has led many plants to question whether instructions should be changed to direct operators to promptly respond and reduce power every time power fluctuates above max power level on an instantaneous reading. Such an approach would require frequent power adjustments and thus frequent reactivity changes. Such reactivity changes introduce greater likelihood of human error and reactivity errors.

Third Sentence:
Licensees may not intentionally operate or authorize operation above the maximum power level as specified in the license.

There is no disagreement that licensees **may not intentionally operate** above the maximum power level as specified in the license. It is understood that this was the primary intent and emphasis of the RIS.

There is, again, no disagreement that licensees **may not authorize operation** above the maximum power level. However, there is a potential for some misinterpretation of procedural steps (or lack thereof) with regard to the actions taken in response to power perturbations. A number of plant actions that are taken during full power operation are known to have the potential to result in a temporary, small exceedance of rated thermal power (RTP). The impact of these actions is monitored and corrective action is taken if necessary to reduce thermal power. However, a “limiting” interpretation could be taken that allowing actions that have the potential to exceed RTP (even if unintentionally, by small amounts, and for brief periods of time) is, in effect, an authorization to operate above the licensed power level.

NEI does not believe that NRC intends RIS 2007-21 to discourage normal full power operation. However, absent replacement guidance to address normal, unintentional exceedances, licensees may feel compelled to either operate at less than nominal full power to ensure that normal power fluctuations do not cause the power level to exceed RTP (derate to add operational margin), or cycle the plant more frequently (rod motion or boron injection) to more closely manage core power. Putting aside commercial concerns with either approach, operational perturbations of this nature could introduce a greater risk factor than that being offset.

Recommended Actions

The 1980 “Jordan memo” and its guidance to inspectors, was developed in full recognition of the difficulties inherent in maintaining “full, steady-state licensed power level” (and similarly worded power limits) along with an acknowledgement of the low safety significance of minor power perturbations above this level. With the exception of instances, as noted in the RIS, where operators have misapplied the guidance to intentionally operate above licensed thermal power, there have been no industry problems or concerns with the “Jordan memo” guidance.

Since the “Jordan memo” guidance has been in use for over 25 years there would appear to be no reason to modify the guidance beyond addition of language to address (exclude) applicability to “intentional” operations above licensed thermal power.

The most expedient course of action to address the issues noted above would be to formally incorporate the “Jordan memo” guidance into NRC inspection guidance for use in determining whether a performance deficiency exists.