September 21, 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 AUGUST 22, 2007

On August 22, 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 ongoing activities relating to the revision of the Significant Determination Process (SDP) appeal process. The staff stated that they will consider changes to the process after the Oconee appeal is completed and will update the working group in future meetings. The staff also gave a presentation on Regulatory Issue Summary (RIS) 2007-21 (Enclosure 6) and addressed industry questions. The staff stated that RIS 2007-021 should be issued next month. The staff stated they will use the Reactor Oversight Process (ROP) feedback form process to make changes to either Inspection Manual Chapters and/or Inspection Procedures if required. The staff then discussed a Mitigating System Performance Index / Consolidated Data Entry (MSPI/CDE) updating issue. The staff and the industry agreed that a Frequently Asked Question (FAQ) should be drafted to address the issue. Nuclear Energy Institute (NEI) stated that they would draft a FAQ for the next meeting.

Other topics that were discussed by staff and industry included Browns Ferry 1 Performance Indicators (PIs) and possible Reactor Coolant System (RCS) leakage PI guidance changes. For RCS leakage, there was further discussion on the objectives of the PI. The staff stated they would schedule a RCS task group meeting in September.

The industry gave a presentation on the Safety Culture Initiative (Enclosure 5) and then addressed staff questions.

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	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	AFW Trains	08/22 Introduced and Discussed	Turkey Point

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, 71.0 and 71.1 were discussed and the issues are being reviewed by both the NRC and Industry Group.

Oconee FAQ 71.5 was tentatively approved; however, the staff has one remaining concern with dual unit outages. The staff will follow up on the issue and make a final decision at the September meeting. Additional input from the Region is required. In addition, changes to the Institute of Nuclear Power Operations (INPO) software are required to accommodate revising the CDE. FAQ 72.0 (DC Cook) and FAQ 72.1 (Turkey Point) were introduced and discussed.

The date for the next meeting of the ROP Working Group is September 19, 2007.

Enclosures:
1. Attendance List
2. Agenda
3. FAQ Log, dated 8/07
4. NEI Action List
5. NEI Safety Culture presentation
6. RIS 2007-21 presentation

The date for the next meeting of the ROP Working Group is September 19, 2007.

Enclosures:
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6. RIS 2007-21 presentation

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OFFICE	DIRS/IPAB	DIRS/IPAB
NAME	JAshcraft	JAndersen for RGramm
DATE	09/21/07	09/21/07

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ATTENDANCE LIST
INDUSTRY/STAFF ROP PUBLIC MEETING

	NAME	AFFILIATION
1	John Butler	NEI
2	Julie Keys	NEI
3	Dave Midlik	SNC
4	Lenny Sueper	NMC
5	Jim Peschel	Florida Power & Light
6	Dave Kanitz	STARS
7	Ken Heffner	Progress
8	Robin Ritzman	FENOC
9	Glen Masters	INPO
10	Darla King	Duke
11	Gary Cananaugh	Fort Calhoun
12	Gerald Sowers	APS
13	Fred Mashburn	TVA
14	Constant Parrish	MIT
15	Roy Lithicum	Exelon
16	Sue Simpson	AEP/DC Cook
17	Mark Peizer	DC Cook
18	Don Olson	Dominion
19	John Thompson	NRC
20	Bob Gramm	NRC
21	John Hanna	NRC
22	Joe Ashcraft	NRC
23	James Andersen	NRC
24	Sonia Burgess	NRC
25	Don Dube	NRC
26	Mary Ann Ashley	NRC
27	Mike Case	NRC
28	Peter Koltay	NRC
29	Tom Hedigan	NRC
30	Eric Bowman	NRC
31	Don Hickman	NRC
32	Jim Kellum	NRC
33	Robert Kahler	NRC
34	Ryan Alexander	NRC
35	Steve Alexander	NRC
36	Sonia Burgess	NRC
37	Monte Phillips	NRC

Enclosure 1

ROP WORKING GROUP PUBLIC MEETING AGENDA

August 22, 2007
9:00 a.m. - 4 p.m.
Ramada Inn
Conference Call Line: 888-913-9966
Pass Code: MARK Meeting Leader: Mark Tonacci

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** 1. SDP appeal process re-review status 2. Core thermal power (Jordon memo) 3. Other Topics	Share information.	1. Koltay 2. Ashley
10:00 - 10:30 a.m.	**Performance Assessment Branch Topics** 1. Safety Culture status 2. DC Cook (FAQ) 3. Other topics	Share information	1.Andersen 2.Keys
10:30 - 10:45 a.m.	**Break - Public Input**		
10:45 - 11:15 a.m.	**Discussion of PI Program Improvements** 1. Brown Ferry 1 PIs 2. RCS Leakage Task Team 3. Safety Culture Initiative	Discuss, share information.	1. Keys 2. Ashcraft 3. Butler
11:15 - 12:00 p.m.	**Discussion of PI Implementation and FAQ Topics** <u>Guidance Issues and Changes</u> 1. MSPI Unavailability Actions 2. Guidance Change White Papers: - MSPI CDE/Basis Change	1. -2. Share information/ Discuss	1. Thompson 2. Thompson /Andersen
	Lunch - **Public Input**		

Enclosure 2

12:00 - 1:00 p.m.			
1:00 - 2:00 p.m.	<u>Guidance Interpretation</u> 1. Kewaunee - appeal (status) 2. Ft. Calhoun 3. Duane Arnold 4. FitzPatrick 5. Oconee 6. DC Cook (moved to morning) 7. Turkey Point	1. August 2, 07 Discuss, gain agreement.	1. Andersen 2. -7. Keys
2:00 - 2:15 p.m.	Break - **Public Input**		
2:15 - 3:00 p.m.	1. Future Meeting Dates 9/19 (already selected) 10/18 tentative 11/? Combine with Dec? 2. Action Item Review 3. Future Topics 4. Meeting Critique	1. Select 2. Review 3. Decide 4. Discuss	1. Andersen 2. Keys 3. All 4. All
3:00 - 3:15 p.m.	Adjourn - **Public Input**		

Enclosure 2

FAQ LOG 08/07

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	AFW Trains	08/022 Introduced and Discussed	Turkey Point

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.

<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.

<u>Issue #4:</u>

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.

__**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.

FAQ 71.1
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.

<u>Question Section:</u>

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

<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.

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.

<u>Licensee and NRC resident/region agree on the facts and circumstances</u>

(Dan Rich to confirm NRC Region 2 agreement)

<u>Potentially relevant existing FAQ numbers</u> N/A

<u>Response Section</u>

Appendix D since this is an Oconee unique issue.

<u>Proposed Resolution of FAQ</u>
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.

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

<u>Response Section</u>

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:

<u>Issue:</u> 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?

<u>Resolution:</u> 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

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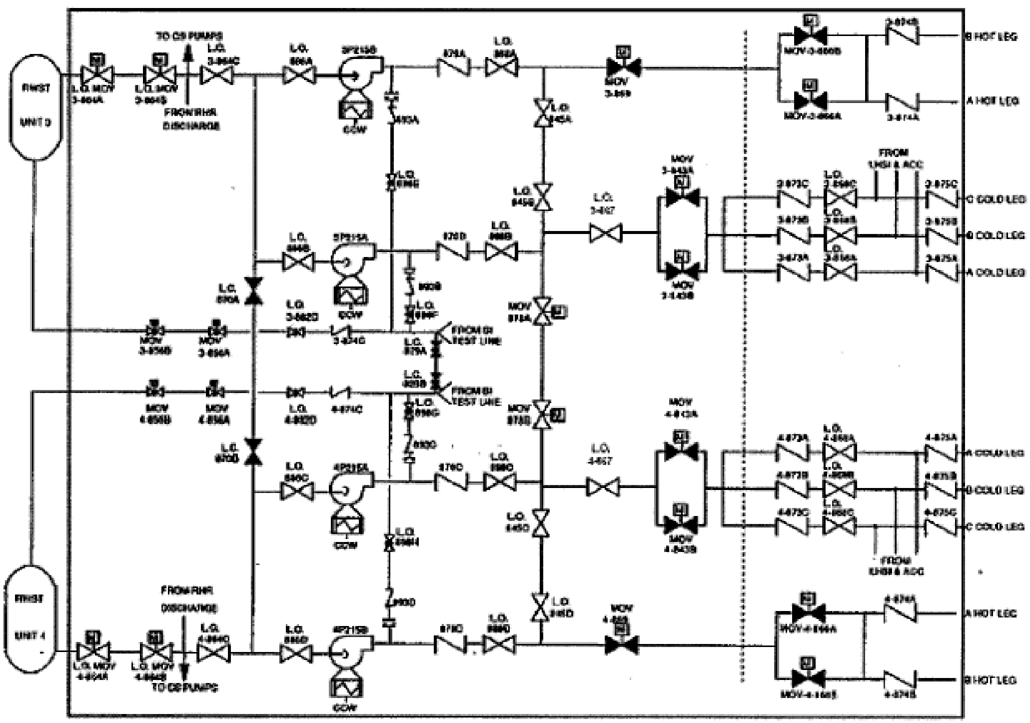

Figure 2.2-1 High Head Safety Injection System

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.

REACTOR OVERSIGHT PROCESS
ROP Working Group Action List – Status August 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	**Aug 2007**
	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.	NEI ROPTF	**Aug 2007**
	Status: 07/07: Team turned over to Joe, discuss with Joe plans to move forward. 08/07:			
06-10	**ROP Newsletter** Issue: Need way to disseminate information to the industry on ROP issues, plans, goals, etc.	Draft ROP Newsletter and send to Licensing Managers	NEI ROPTF	**Oct 2007**
	Status: *Ongoing Quarterly Newsletter. July Newsletter issued*			
07-01	**MSPI Data Collection** Issue: Discuss ways to make MSPI data collection more efficient		NEI ROPTF	**Aug 2007**
	Status: Self assessment issued/data review ongoing 08/07: Analyze results, document and make recommendations.			
07-05	**MR Approval** Obtain NRC Approval of NEI 93-01 letter to align Maint. Rule with ROP.		NRC Steve Alexander	**Aug 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 update.			

Enclosure 4

Safety Culture Initiative Implementation

John C. Butler

Director, Safety Focused Regulation

Nuclear Energy Institute

Enclosure 5

Safety Culture Implementation

- Began implementation on July 1, 2006
- 18-month implementation period
- Opportunities for stakeholder feedback are being provided
  - ROP monthly public meetings
  - Regional utility group meetings
  - Today's meeting

NEI

Enclosure 5

Purpose of Implementation Period

- Monitor to ensure that ROP process continues to meet regulatory principles:
  - Objective
  - Understandable
  - Predictable
  - Transparent
  - Risk informed
  - Performance based
- Assess need for revisions in order to meet intended objectives and outcomes

With any new process there are concerns

- Shades of Green returns
- Effectiveness of being an early indication of decline
- Many more Substantive Cross Cutting Issues (SCCI)
- Focusing on low significance issues
- Closing out a SCCI- how?
- Changes to CAP to serve ROP
- Multiple aspects per finding
- Inspecting safety culture
- Low threshold for SCWE SCCI
- Confusion in addressing SC between NRC process and INPO process

NEI

Enclosure 5

Focusing on low significance issues

- Commission provided staff direction on Safety Culture Initiative in an SRM on SECY-05-0187, dated December 21, 2005
- This direction included:

  "Ensure that the resulting modifications to the ROP are consistent with the regulatory principles that guided the development of the ROP"

- A key ROP principle is that findings of low significance will not be combined and treated in total as an issue of greater significance (e.g., no aggregation of findings)

NEI

Focusing on low significance issues

Observations:

- The thresholds/criteria used to identify “greater than minor” findings are not well defined
- Since 2003, there has been a substantial increase in the percentage of findings with an associated cross-cutting aspect.
- The first criterion for identification of a substantive cross-cutting issue is more than three greater than minor inspection findings with cross-cutting aspects in the same area during a 12-month assessment period
- There are significant regional variations in the percentage of findings with an associated cross-cutting aspect.
- A relatively high percentage of findings are assigned to relatively few cross-cutting aspects (e.g., failure to follow procedure, effectiveness of corrective action)

NEI

Focusing on low significance issues

Contributing Concerns:

- The current screen for “greater than minor” findings sets a very low threshold
- The assignment of cross-cutting aspects retains a high degree of subjectivity
- This more readily leads to assignment of cross-cutting aspects to findings of little or no significance
- The first threshold for a substantive cross-cutting issue aggregates cross-cutting aspects irrespective of significance
- There is currently no mechanism to screen out or address cross-cutting aspects of low significance

NEI

Focusing on low significance issues

Possible Means to Address Concern:

1. Improve process for identifying greater-than-minor findings
2. Improve process for assigning cross-cutting aspects to findings (both threshold and guidance)
3. Review and modify, if appropriate, threshold values for identification of substantive cross-cutting issues

NEI

Improving Process for "Greater than Minor"

- Process outlined in MC 0612 Appendix B, *Issue Screening*
- Finding is first compared against examples in MC 0612 Appendix E
- If no match is found, then the following questions are asked:
  1. Could the finding be reasonably viewed as a precursor to a significant event?
  2. If left uncorrected would the finding become a more significant safety concern?
  3. Does the finding relate to a performance indicator (PI) that would have caused the PI to exceed a threshold?
  4. Is the finding associated with one of the cornerstone attributes listed at the end of this attachment and does the finding affect the associated cornerstone objective?
  5. Does the finding relate to [listed] maintenance risk assessment and risk management issues?

NEI

Improving Process for "Greater than Minor"

- In practice,
  - few findings "match" examples provided in Appendix E
  - Results in majority of findings being run through questions in Appendix B
  - Question 4 "captures" more findings than any other question
- Question 4 is loosely worded, making effective and consistent implementation difficult
  - Is the finding **associated with** one of the cornerstone attributes listed at the end of this attachment and does the finding **affect** the associated cornerstone objective?

NEI

Improving Process for "Greater than Minor"

- Potential Areas for Improvement:
  - Additional examples
  - Modify examples to more clearly identify aspects leading to "greater than minor"
    - Under what circumstances would the finding be minor?
  - Modify use of examples to illustrate proper application of questions
  - Modify questions

NEI

Improving process for assigning CC aspects

- Once a finding has been determined to be "greater than minor" a determination is made as to whether a cross cutting aspect should be assigned
- In practice,
  - Process is subjective, leading to noted variations in % findings assigned an aspect
  - Potential for subjective selection of "bin"

NEI

Improving process for assigning CC aspects

- Potential areas for improvement
  - Improve guidance to minimize subjectivity
  - Consider application of “threshold”
  - Encourage/guide better documentation of contributing causes

NEI

Improving Process for Identification of SCCI

- Process currently applies three criteria for identification of SCCI:
  - More than three green or safety-significant inspection findings with CC aspects in same CC area
  - Causal factors have a common theme
  - NRC has a concern with licensee's scope of efforts or progress in addressing related performance issues
- Potential areas of improvement
  - Consider application of different thresholds for different CC areas

NEI

Beyond 18-month Implementation

- Initial implementation period ends 12/31/2007
  - Results will be provided to Commission as part of ROP Self-Assessment Commission paper
  - Lessons learned will be used to make necessary changes
- Results thus far indicate:
  - Some areas where guidance can be improved
  - Issues/concerns pointing to need for additional data and continued discussion on ways to address
  - A degree of industry anxiety remains but there are no calls to “scuttle”
- Growing recognition that monitoring should continue
  - 18 months insufficient time to fully exercise all aspects of program
  - Need to shepherd any program changes resulting from initial implementation
  - Need to avoid unexpected evolutions once implementation “spotlight” is diminished

NEI

Generic Communication on Adherence to Licensed Power Limits

Mary Ann Ashley
NRR Enforcement Coordinator
301-415-1073, mab@nrc.gov

Enclosure 6

Background

- Maximum Power Level
  - License condition
  - “At steady-state power levels up to a maximum of xxxx megawatts (thermal)” or variations on this wording

- 1980 ‘Jordan Memo’ provided enforcement guidance to inspectors

- Industry use of enforcement guidance as operational guidance
  - Sequoyah - 1989
  - Kewaunee - 2005
  - Dresden - 2006
  - Wolf Creek - 2007

Regulatory Issue Summary 2007-21

- Intent: Remind licensees of the regulatory requirement to adhere to the Maximum Power Level identified in their plant license.

- “Jordan Memo” guidance is being superseded.
  - Current ROP tools are adequate for determining how to treat performance deficiencies related to exceeding the maximum power level.

- Recognizes that maintaining power exactly at the maximum level identified in the license is not always possible due to normal plant changes

- Focuses on the intentional aspects of exceeding the limit

Not a backfit because:

- Applicable staff position for maximum power level is the operating license

- Jordan memo is not considered an ‘applicable staff position’
  - Content explicitly for use by NRC staff
  - Enforcement action taken

- Superseding internal guidance on enforcement discretion is not a new or different staff position and does not constitute a backfit