Enclosure 3

Reactor Oversight Process Task Force FAQ Log – November 19, 2014

FAQ Log Entering Nov. 19 ROP WG Meeting

FAQ No.	PI	Topic	Status	Plant/Co.	Point of Contact
14-02	MS	Fort Calhoun MSPI	Introduced 05/14/2014 Discussed 7/16/2014. Discussed 9/11/2014 staff questions about basis for 5 quarters vice 4 quarters. Staff questions received 10/17 and DISCUSSED 10/22.	Plant-Specific Fort Calhoun	Erick Matzke (OPPD) John Kirkland (NRC)
14-03	IE04	ANO-2 USwC	Introduced 05/14/2014. Discussed 7/16/2014. Staff response received 10/17. Tentative FINAL 10/22.	Plant-Specific ANO-2	Stephenie Pyle (Entergy) Matt Young (NRC)
14-05	EP03	Hatch New Siren System Data	Introduced July 16 Tentative Final 9/11/2014 Approved Final 10/22/2014. Effective April 1, 2015. NRC FINAL TEXT REC'D 11/7/14	Plant-Specific Hatch	Charles Brown (Southern) TBD (NRC)
14-06	IE03	VY Downpower	Introduced 9/11/2014 Staff questions were DISCUSSED 10/22/2014	Generic	Coley Chappell (Entergy) Scott Rutenkroger (NRC)
14-07	EP03	Point Beach ANS	Introduced and discussed 10/21/2014	Plant-Specific Point Beach	Gerard Strharsky (NextEra) James Beavers (NRC)
14-XX (Proposed)	MS06	Prairie Island Lockout	To be introduced	Generic	Laura Jean Noonan (Xcel) Karla Stoedter (NRC)

For more information, contact: James Slider, (202) 739-8015, jes@nei.org

NEI 99-02 FAQ 14-02
Fort Calhoun MSPI

Plant: Fort Calhoun Nuclear Station

Date of Event: 12/18/2013 (Reactor Critical)

Submittal Date: 05/14/2014

Licensee Contact: Erick Matzke **Tel/Email:** 402-533-6855 ematzke@oppd.com

NRC Contact: Louis Cruz **Tel/Email:** 301-415-3982 louis.cruz@nrc.gov

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

MS07 Mitigating System Performance Index (High Pressure Injection Systems)

MS08 Mitigating System Performance Index (Heat Removal Systems)

MS09 Mitigating System Performance Index (Residual Heat Removal Systems)

MS10 Mitigating System Performance Index (Cooling Water Systems)

Site-Specific FAQ (Appendix D)? Yes

FAQ requested to become effective: When approved**.**

Question Section

NEI 99-02, Revision 07, Guidance needing interpretation and/or additional information:

The MSPI Section (starting on page 32) does not provide guidance on the process involved in reporting performance indicator data for licensees that have started up after having been in a shutdown condition for an extended period of time. MSPI values are sensitive to unavailability hours when the critical hours for a unit are low, as is the case with a plant starting up after an extended shutdown. In this, MSPI may not be a valid indication of performance and should be considered not valid until sufficient critical hours are accrued.

The draft NRC Staff White Paper on Performance Indicator Validity during Extended Shutdown and Subsequent Startup, last discussed at the April 2014 ROP Working Group meeting notes:

"For plants that are in extended shutdown conditions, the MSPI data elements continue to be reported. Once the licensee anticipates that a shutdown will enter an extended period (six months), a FAQ shall be submitted for the ROP Working Group to determine MSPI validity. The licensee shall submit an additional FAQ to establish MSPI validity upon subsequent startup."

Timeline of significant events for Fort Calhoun Station:

April, 2011 – Fort Calhoun Nuclear Station shut down: 26 Refueling Outage.

June 6, 2011 – Declared a Notification of Unusual Event – Rising flood waters

August 29, 2011 Exited Notification of Unusual Event – River Level 1003'6" and lowering

June 7, 2011 – 1B4A Load Center fire

December, 2011 – FCS entered Inspection Manual Chapter 0350.

December 21, 2013 – Breakers closed and extended outage ended.

NRC Resident Comments

Residents Inspector had no comments.

Licensee Position

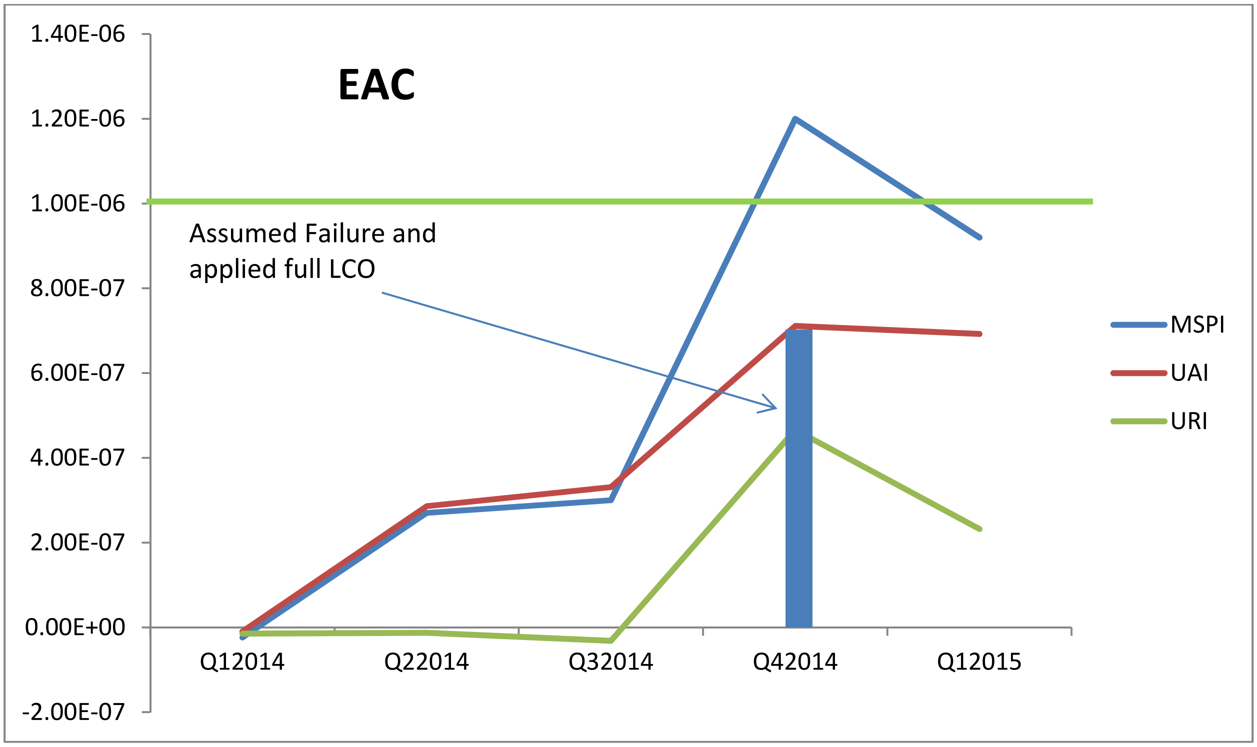
FCS will continue monitoring MSPI and reporting data elements on a quarterly basis. The performance indicator shall remain N/A until reported data is expected to be a more accurate reflection of current plant performance.

The lack of critical hours for the past 12 quarters has and will continue to skew the performance indicators validity. As critical hours are accrued, performance and predictability becomes increasingly representative of actual performance of the station. As one of the basic premises of MSPI is that a single failure should not result in an adverse indicator, the following criteria were used by Ft. Calhoun Station to determine when there will be sufficient critical hours to avoid a false positive indicator:

1. There should be at least 4 quarters of data following the startup from the extended outage, and
2. The MSPI value should be able to tolerate the worse single failure and unavailability equal to a full LCO Completion time and remain Green (≤1.0E-6/yr) following startup from the extended outage.

A plant specific PWR Owners Group "What-If" tool was used to predict future MSPI values using expected plant data (Unavailability and Unreliability).

The charts below illustrates the impact for the EAC and RHR systems from having a failure and associated unavailability in the 4th quarter 2014 and the impact on MSPI as additional critical hours are accrued:



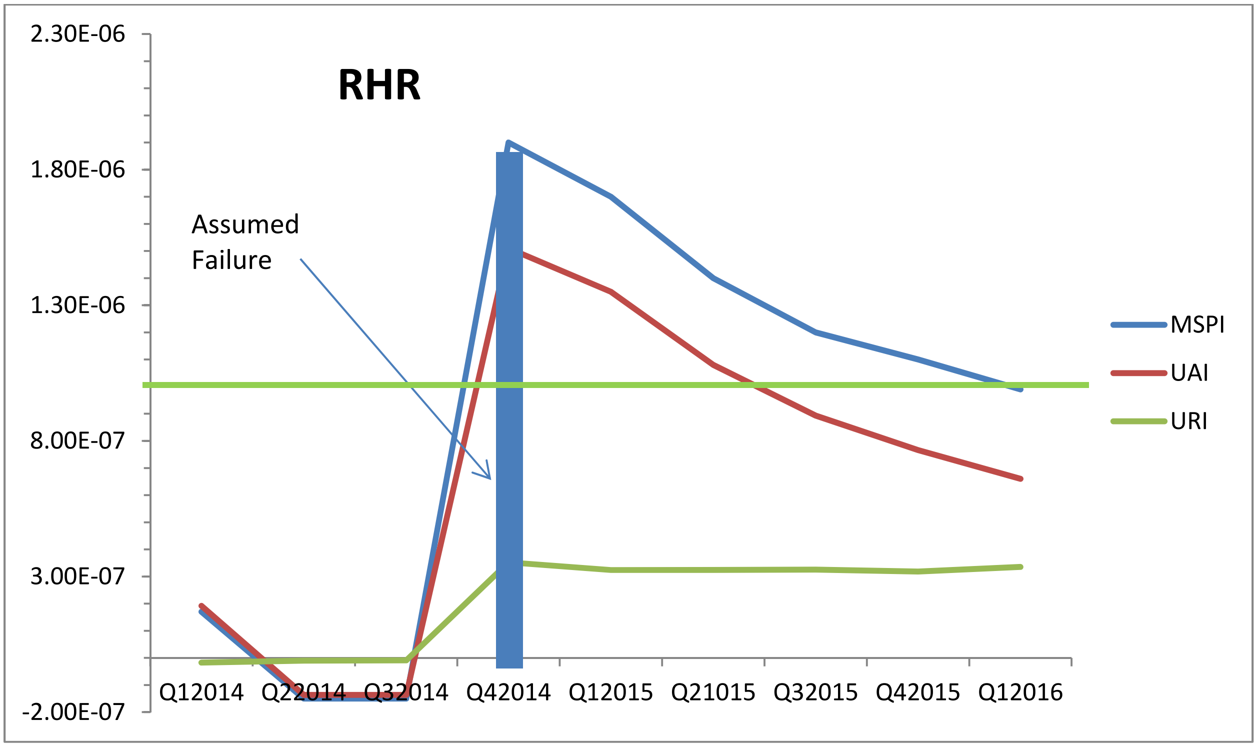
EAC	Q12014	Q22014	Q32014	Q42014	Q12015
MSPI	-2.4E-08	2.7E-07	3.0E-07	1.2E-06	9.2E-07
UAI	-9.50E-09	2.86E-07	3.31E-07	7.11E-07	6.92E-07
URI	-1.49E-08	-1.31E-08	-3.18E-08	4.66E-07	2.32E-07
% Baseline Crit Hrs	9.7%	18.7%	27.8%	35.6%	45.8%

Q1 2015 MSPI decrease reflects a Feb 2012 failure dropping out of the 3 year monitoring period.

Both DG 2 Year Overhauls (103 hours each) are included in 2014 estimate.

Past MSPI values reflect original estimate for observed period.

NEI 99-02 FAQ 14-02
Fort Calhoun MSPI



RHR	Q12014	Q22014	Q32014	Q42014	Q12015	Q21015	Q32015	Q42015	Q12016
MSPI	1.7E-07	-1.5E-07	-1.5E-07	1.9E-06	1.7E-06	1.4E-06	1.2E-06	1.1E-06	9.9E-07
UAI	1.92E-07	-1.37E-07	-1.37E-07	1.51E-06	1.35E-06	1.08E-06	8.93E-07	7.66E-07	6.60E-07
URI	-1.73E-08	-1.05E-08	-9.47E-09	3.52E-07	3.24E-07	3.24E-07	3.25E-07	3.18E-07	3.35E-07
% Baseline Crit Hrs	9.7%	18.7%	27.8%	35.6%	45.8%	50.2%	59.4%	68.5%	77.5%

Estimated planned unavailability hours for each quarter: 7 hours.

RFO27 is scheduled for 45 days during Q2_2015.

Potentially relevant existing FAQ numbers: None

Response Section

Based on the results of this sensitivity study, the following table identifies when each MSPI should be considered valid:

MSPI System	Effective Date	Limiting Criteria
MS06 – Emergency AC Power	1st quarter 2015	Single Failure plus associated unplanned unavailability (full LCO) yields white indicator in 4th quarter 2014 but green in 1st quarter 2015
MS07 – High Pressure Injection System	4th quarter 2014	4 quarters data
MS08 – Heat Removal System	4th quarter 2014	4 quarters data
MS09 – Residual Heat Removal System	1st quarter 2016	Single Failure plus associated unplanned unavailability (full LCO) yields white indicator in 4th quarter 2015 but green in 1st quarter 2016
MS10 – Cooling Water System	4th quarter 2014	4 quarters data

NRC Response

FAQ 14-02: FCS MSPI Validity

NRC Response

According to the "Simulation of MSPI Indicator Reaction to Plant in Long Term Shutdown and Initial Startup Page" white paper discussed in the ROP Working Group (The last documented version of this white paper is available through Agencywide Document Access and Management System (ADAMS) Accession No. ML13079A728), the ROP Task Force recommended and the NRC staff agreed with the following:

ROP Task Force Recommendations

The data from this study (Figure 1) shows that MSPI is very reactive when critical hours are low. This indicates that these situations should be treated on a case-by-case basis. Fortunately, these situations have been uncommon over the life of the ROP, so that it is practical to consider a case-by-case approach. As a starting point for these case-by-case discussions, the ROP Task Force recommends the following decision rules for the display of MSPI on the NRC web page:

- *Gray out MSPI when a unit has been shut down for six months.*
  - *On plant startup, if the calculated MSPI is greater than 1.0E-6 (White) for the quarter prior to startup, MSPI will remain grayed out until 12 months of operation have accumulated after startup.*
  - *On plant startup, if the calculated MSPI is less than or equal to 1.0E-6 (Green) for the quarter prior to startup, MSPI will remain grayed out until there is a total of 12 months of operation in the 3-year monitoring period.*
- *Gray out MSPI for the startup of new plants until 12 months of operation have accumulated*

Given that FCS restarted on December 2013, the quarter prior to startup is 3Q-2013. All MSPI values for FCS were green in 3Q-2013. Therefore, the starting point in treating the validity of the MSPI indicators is that: *MSPI will remain grayed out until there is a total of 12 months of operation in the 3-year monitoring period.* For this particular case, 4Q-2014 represents the time-frame at which a total of 12 months of operation have been accumulated.

In this FAQ, the licensee, FCS, proposes that the High Pressure Safety Injection (HPSI) system MSPI, Heat Removal System (HRS) MSPI, and Cooling Water System (CWS) MSPI become valid on the 4th quarter of 2014. However, FCS proposes that the Emergency AC (EAC) power and Residual Heat Removal (RHR) system MSPI indicators become valid on the 1st quarter of 2015 and 1st quarter of 2016, respectively.

FCS predicted future MSPI values using a Pressurized Water Reactor Owners Group "What-if" tool and expected plant data for unavailability and unreliability. These estimated MSPI values defined the licensee's proposal of the respective effective dates for each MSPI indicator to become valid. The NRC staff agrees with the proposal for the HPSI, HRS, and CWS MSPIs to become valid on 4Q2014, and for the EAC MSPI to become valid on 1Q2015. However, the NRC staff does not agree with the proposal for the RHR MSPI to become valid on 1Q2016.

The staff recognizes that the approach to maintain the RHR MSPI indicator invalid before 9 quarters of operational data have been accrued proactively prevents the indicator from resulting in a false positive due to accrued unplanned unavailability. However, various factors such as increase in inspection resources, aggregation of various inputs to the indicator, alignment with previously established positions, and external stakeholder communications should also be taken into consideration when defining an effective date for the indicator to become valid.

- Having the RHR MSPI invalid before 9 quarters of data have been accrued will increase inspection resources. While a baseline inspection approach would be applied to all other systems covered by MSPIs, additional inspection hours would have to be implemented to gain performance insights on the RHR system.
- Having the RHR MSPI invalid before 9 quarters of data have been accrued limits the indicator from providing insights on RHR performance based on the estimated outcome of accrued unplanned unavailability. It does not allow the indicator to provide insights on RHR performance that might result from any other failures and/or unavailability observed under this indicator.
- The approach of having the RHR MSPI invalid before 9 quarters of data have been accrued results in a significantly different treatment from that used for the other MSPIs. It also diverges noticeably from the starting point for evaluation of such situation that was discussed through white papers in the ROP WG (ADAMS Accession No. ML13079A728), and the initial characterization of this FAQ. Such divergent approach can impact the overarching ROP goals of understandability and predictability.
- Having the RHR MSPI invalid before 9 quarters of data have been accrued while all other MSPI indicators are treated as valid performance indicators can present communication challenges to external stakeholders. Such unique approach would impact the clarity of the performance indicator program.

Since historical data on RHR unplanned unavailability was not considered, accounting for the Technical Specifications (TS) Allowed Outage Time (AOT) (i.e., 7 days) could be a highly conservative estimate. If an indicator is really “invalid” for 9 of a total of 12 quarters (75%), what other types of implications can be inferred? Although TS SSCs in general make-up the list of monitored components in MSPI, the AOTs, surveillance frequencies, etc. do not necessarily correlate with risk importance (i.e., maybe TS AOTs is not a good input to use for a risk-based calculation).

The NRC staff concludes that: (1) the HPSI, HRS, and CWS MSPIs should become valid on 4Q2014, and (2) the EAC and RHR MSPIs should bercome valid on 1Q2015.

NEI 99-02 FAQ 14-03
ANO Scram March 31, 2013

Plant: Arkansas Nuclear One Unit 2 (ANO-2)

Date of Event: March 31, 2013

Submittal Date: March 20, 2014

Licensee Contact: Stephenie Pyle Tel/email: 479-858-4704 / spyle@entergy.com

NRC Contact: Matt Young Tel/email: 479-858-3113 / matt.young@nrc.gov

Performance Indicator:

IE04 - Unplanned Scrams with Complications (USwC)

Site-Specific FAQ (see Appendix D)? Yes

FAQ to become effective: October 30, 2014

Question Section

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

Pg H-4 Lines 27, 28, 29

Since all PWR designs have an emergency feedwater system that operates if necessary, the availability of the normal or main feedwater system as a backup in emergency situations can be important for managing risk following a reactor scram.

Pg H-5 Lines 3, 4, 5

Condenser vacuum, cooling water, and steam pressure values should be evaluated based on the requirements to operate the pumps and may be lower than normal if procedures allow pump operation at that lower value.

Event or circumstances requiring guidance interpretation:

ANO-2 Loss of a Condenser Vacuum due to Transfer to Startup Transformer #2 (SU2)

In determining if a scram is complicated/uncomplicated, the guidance asks "Was **main** feedwater unavailable or not recoverable using approved plant procedures during the scram?" *(emphasis added)* The question fails to include the phrase “normal or” as stated in H-4 above. The intent is to determine if a backup feedwater source is available should Emergency Feedwater (EFW) fail.

The NEI 99-02 guidance uses the term Auxiliary Feedwater (AFW) interchangeably with EFW. ANO-2 has two EFW pumps and has installed a low power feedwater system referred to as AFW. The ANO AFW pump (2P-75) and its connections to the EFW and the main feedwater (MFW) headers has called into question whether it is a "normal or main Feedwater system as a backup in emergency situations" and an “electric-driven main feedwater pump”.

Beginning March 31, 2013, ANO-2 has experienced the loss of condenser vacuum due to the transfer of the offsite power sources to Startup Transformer #2 (SU2) on two separate occasions. Since SU2 is shared between the two units at ANO, SU2 power feed to 4160V switchgear 2A-2 breaker and SU2 power feed to both 6900V switchgear 2H-1 and 2H-2 are maintained in pull-to-lock per procedure OP-2107.001, Electrical System Operation (normal configuration). This avoids a challenge to the millstone relay setpoints should both ANO units transfer to SU2 simultaneously. In both events SU2 automatically powered 4160 V switchgear 2A-1 successfully, which in turn provided offsite power to safety bus 2A-3. Switchgear 2A-1 remained energized throughout the events.

ANO-2 has two offsite power sources: SU2 and Startup Transformer #3 (SU3). When available (i.e., not removed from service for maintenance, testing, or grid conditions), SU3 is the preferred source of offsite power following a reactor trip. This is because SU3 is not shared between the two ANO units and, therefore, no load shedding is required for transfer to SU3. A reactor trip with SU3 available will automatically result in MFW being reduced to a single MFW pump (both MFW pumps are high capacity steam-driven pumps), which is driven to minimum speed and respective valves driven to minimum positions (referred to a reactor trip override or RTO). The MFW system is subsequently manually secured and the electric-driven AFW pump placed in service to maintain hot standby conditions or to support plant cooldown. When AFW is available, all plant startups and shutdowns are performed with AFW as the preferred source. The AFW pump is capable of supplying sufficient feedwater flow to remove decay heat up through ~4% reactor power. The AFW pump is tested quarterly in accordance with Supplement 8 of procedure OP-2106.006, Emergency Feedwater System Operations.

When SU3 is unavailable, switchgear 2A-1 loads are transferred to SU2 as described above. However, the two circulating water pumps necessary to maintain condenser vacuum are powered from 2H-1 and 2H-2, which are not automatically transferred to SU2. SU2 continues to supply power to vital buses and some non-vital equipment, although the AFW pump is also initially load-shed if in operation.

By design and as discussed previously, unavailability or a lockout of SU3 results in the loss of non-vital circulating water pumps and the subsequent loss of condenser vacuum. In relation to the aforementioned ANO events, the loss of condenser vacuum initially results in the loss of MFW pump (high exhaust pressure). Procedures provide the necessary instructions to defeat the load shed relay for the AFW pump if EFW is lost or to support plant cooldown as needed. In addition, procedures provide the necessary instructions to restart the MFW pump without vacuum if both EFW and AFW become unavailable. Either of these backup options to EFW can be accomplished within approximately 30 minutes and prior to Steam Generator dry-out (reference NEI 99-02, H1.5). During the subject ANO events, no equipment malfunctions occurred that would have prevented at least one of the backup options from being utilized if needed. The AFW pump can be supplied directly from the Condensate Storage Tanks, does not rely on condenser vacuum or portions of the MFW system, and is the normal and preferred feedwater source to support plant cooldown, heatup, hot standby conditions, and startup (Emergency Operating Procedure (EOP) OP-2202.002, Reactor Trip Recovery, Step 12, among all the relevant EOPs, Abnormal Operating Procedures (AOPs), and Normal Operating procedures, place 2P-75 pump in service as the preferred source). All necessary features which support operation of 2P-75 remained available.

Applicable procedure steps from reactor trip through completion of restarting a MFW pump without condenser vacuum were reviewed and qualitatively timed. The timing was reviewed by Operations personnel including SRO's responsible for simulator training. GE input was obtained which qualitatively confirmed MFW pump capability to operate with no condenser vacuum for several hours. ANO-2 Reactor Coolant System parameters were stabilized in the subject scram event in less than 30 minutes, upon the establishment of natural circulation cooling. Plant stabilization via natural circulation cooling would not be delayed if MFW pump restart had been required.

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

With respect to feedwater sources, Entergy has determined the scram to be uncomplicated because at least one or more "normal or main" feedwater sources remained available as backup to the EFW system, as designed. The aforementioned timing and flow path through relevant procedures was provided to the ANO NRC Resident inspector. In addition, GE provided information, based on engineering judgment, regarding the operation of the MFW pump under a loss of vacuum condition. Based on the information provided, the ANO NRC Resident Inspectors and associated NRC Regional personnel have verbally concurred that a MFW pump could likely have been recovered within 30 minutes and, therefore, the subject scrams should be considered uncomplicated.

Potentially relevant FAQs:

FAQ 481 (10-02) significantly revised Section 2.1 of NEI 99-02 Rev 7 on August 31, 2013.

FAQ 467 response: "availability of feedwater beyond 30 minutes and whether consideration of the scram response time window remains an appropriate marker for judging a complication to recovery from an unplanned scram"

5

<u>Response Section</u>

Proposed Resolution of FAQ:

Due to the plant design of ANO-2, the response to the guidance question:

> "Was main feedwater unavailable or not recoverable using approved plant procedures during the scram?"

Should be "NO" provided that the MFW and/or AFW pump was available for use within an estimated 30 minutes in both events.

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

Because this FAQ is site-specific, no wording changes are proposed with regard to NEI 99-02. This FAQ concludes that the ANO-2 Auxiliary Feedwater pump provides an appropriate electric-driven backup feedwater capability to the ANO-2 safety-related Emergency Feedwater system.

PRA update required to implement this FAQ? No

MSPI Basis Document update required to implement this FAQ? No

NRC Response

The NRC staff used the following reference from NEI 99-02 during the review of this FAQ:

Pg H-4 Lines 27, 28, 29

"Since all PWR designs have an emergency feedwater system that operates if necessary, the availability of the normal or main feedwater system as a backup in emergency situations can be important for managing risk following a reactor scram."

For this event, ANO proposes that backup to EFW could have been provided in two ways: (1) using AFW, or (2) restarting MFW without condenser vacuum. The staff's review was focused on the licensee's ability to recover MFW, since NEI 99-02 highlights the importance of having normal or main feedwater available as a backup to EFW in emergency situations. NEI 99-02 does not discuss the applicability of AFW as a backup to EFW under the Unplanned Scrams with Complications PI.

The staff reviewed the licensee's procedures for restarting MFW without condenser vacuum and agrees that MFW could likely have been recovered within 30 minutes. The staff also recognizes that the Reactor Cooling System parameters were stabilized in less than 30 minutes, and that the MFW pump could operate without condenser vacuum for several hours, according to the information provided in this FAQ. The staff concludes that this event does not count in the Unplanned Scram with Complications PI.

~~The staff proposes to consider revising the language in NEI 99-02 to clarify the applicability of AFW as backup to EFW in emergency situations under the scope of the Unplanned Scrams with Complications PI.~~

Proposed FAQ

Vermont Yankee Downpower

Plant: Vermont Yankee Nuclear Power Station (VY)

Date of Event: 2/23/2014

Submittal Date: ____________

Licensee Contact: Coley Chappell **Tel/Email:** 802-451-3374 cchappe@entergy.com

NRC Contact: Scott Rutenkroger **Tel/Email:** 802-258-5144 Scott.Rutenkroger@nrc.gov

Performance Indicator: UNPLANNED POWER CHANGES PER 7000 CRITICAL HOURS (IE03)

Site-Specific FAQ (Appendix D)? No

FAQ requested to become effective: Upon approval

Question Section

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

Revision 7

Page 13
25 *Unplanned change in reactor power, for the purposes of this indicator,* is a change in reactor
26 power that (1) was initiated less than 72 hours following the discovery of an off-normal
27 condition that required or resulted in a power change of greater than 20% of full power to
28 resolve, and (2) has not been excluded from counting per the guidance below. Unplanned
29 changes in reactor power also include uncontrolled excursions of greater than 20% of full power
30 that occur in response to changes in reactor or plant conditions and are not an expected part of a
31 planned evolution or test.

Page 14
4 The 72-hour period between discovery of an off-normal condition and the corresponding change
5 in power level is based on the typical time to assess the plant condition, and prepare, review, and
6 approve the necessary work orders, procedures, and safety reviews, to effect a repair. The key
7 element to be used in determining whether a power change should be counted as part of this
8 indicator is the 72-hour period and not the extent of the planning that is performed between the
9 discovery of the condition and initiation of the power change.

Page 14
35 Examples of occurrences that are **not** counted include the following:
36 • Planned power reductions (anticipated and contingency) that exceed 20% of full power
37 and are initiated in response to an off-normal condition discovered at least 72 hours
38 before initiation of the power change.

Page 15

If a condition is identified that is slowly degrading and the licensee prepares plans to reduce power when the condition reaches a predefined limit, and 72 hours have elapsed since the condition was first identified, the power change does not count. If however, the condition suddenly degrades beyond the predefined limits and requires rapid response, this situation would count. If the licensee has previously identified a slowly degraded off-normal condition but has not prepared plans recognizing the potential need to reduce power when the condition reaches predefined limits, then a sudden degradation of that condition requiring rapid response would constitute a new off-normal condition and therefore, a new time of discovery.

Page 17

This indicator captures changes in reactor power that are initiated following the discovery of an off-normal condition. If a condition is identified that is slowly degrading and the licensee prepares plans to reduce power when the condition reaches a predefined limit, and 72 hours have elapsed since the condition was first identified, the power change does not count. If, however, the condition suddenly degrades beyond the predefined limits and requires rapid response, this situation would count.

Event or circumstances requiring guidance interpretation:

As a result of excessive leakage identified on Reactor Feedwater Pumps (RFP) "A" and "B" mechanical seals, the station developed and approved an Operational Decision-Making Issue (ODMI) on February 4, 2014. The ODMI implemented an enhanced monitoring plan, established contingency actions to be taken when preset leakage rates were exceeded, directed actions to be taken using normal plant operating procedures, and addressed degraded seals on both "A" and "B" RFPs. ODMI trigger points and actions are summarized below, and are not necessarily sequential. For comparison, seal leakage less than 200 mL/min is considered acceptable.

ODMI Trigger Point 1: 1000 mL/min seal leakage. Make appropriate notifications, Engineering trend and evaluate leakage and determine if RFP seal(s) should be replaced.

ODMI Trigger Point 2: 1500 mL/min seal leakage. Make appropriate notifications, schedule down power for pump seal replacement 10 to 14 days in advance.

ODMI Trigger Point 3: Signs of steady stream of steam from the seal area. Make appropriate notifications, reduce power and remove affected RFP from service and isolate RFP if necessary.

Upon implementation, each operating crew was required to review the ODMI and the normal feedwater operating procedure. Heightened surveillance required by the ODMI included Operators measuring leakage on RFP "A" inboard and RFP "B" outboard seals every 4 hours and logging the results in the Control Room log. Contingency actions were put in place since the exact time when a degraded seal might reach a trigger point could not be known in advance. The plant operators and site organization fully understood what actions would be taken if the ODMI trigger points were reached. The actions described below were in accordance with the ODMI plan.

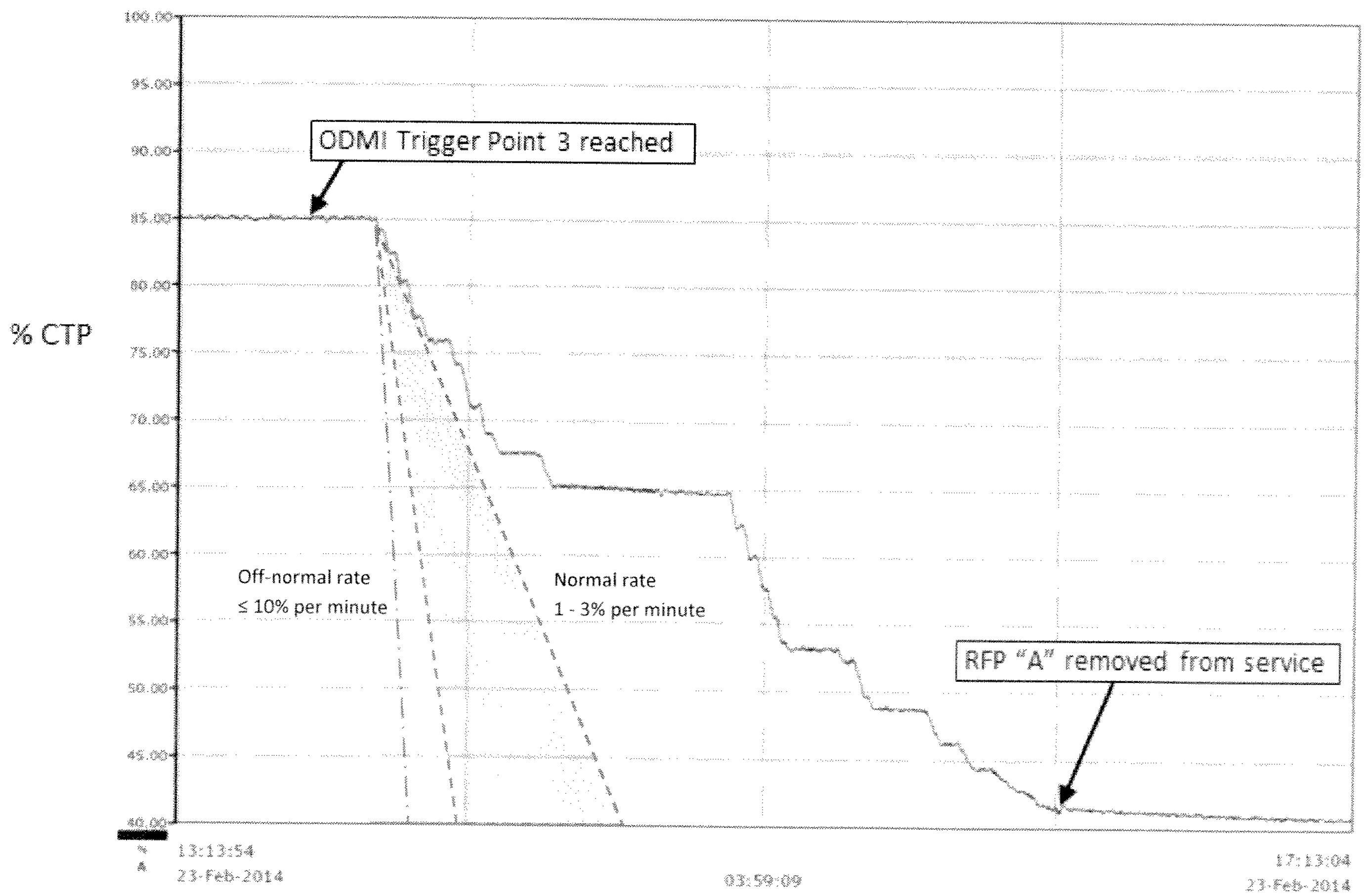
On February 21, 2014, Vermont Yankee reduced power to 80.2% to support seal repairs to "B" Reactor Feedwater Pump (RFP), in accordance with ODMI directed actions.

On February 23, with reactor power held steady at 85% and seal repairs to RFP "B" in progress, at 0420 the inboard seal leakage on RFP "A" was reached ODMI Trigger Point 2 and remained in the range of 1500-1600 mL/min for approximately another 10 hours. At 1345, Control Room Operators received a report of steaming from the RFP "A" inboard seal (ODMI Trigger Point 3), made appropriate notifications, and at 1355 commenced reducing power in accordance with the ODMI using normal operating procedures. By 1615 power was lowered to approximately 40%, and the "A" RFP was then removed from service.

Power was reduced at a rate of about 1.4 % per minute or less, and the entire power reduction from 85% to 40% occurred over a period of 2 hours and 11 minutes. Normal operating procedures specify a rate of 1-3% per minute. For comparison, the off-normal operating procedure specifies a power reduction rate of ≤ 10 % per minute.

On February 24, seal repairs to RFP "A" and RFP "B" were completed, and Control Room Operators commenced raising power. Reactor power was returned to 100% on February 26.

The reduction in power to 40% to remove RFP "A" from service is shown in the figure below.



LICENSEE POSITION:

Vermont Yankee did not classify the power reduction on February 21 to address RFP "B" seal repairs as unplanned because the power change was less than 20% of full power.

The power reduction on February 23 to address RFP "A" seal repairs was not classified as an unplanned power change because the RFP seal leakage had been identified as a degraded condition greater than 72 hours prior to initiating the power change, the condition did not degrade beyond the predefined limits specified in the ODMI and did not require a rapid response. Excessive RFP "A" inboard seal leakage had been monitored and trended by the on shift Operators for more than two weeks. The power reduction was performed in accordance with the ODMI anticipated and contingency actions, and was made using normal operating procedures. The ODMI actions were well understood by the operating crews. The basis for this conclusion is interpretation of the guidance as discussed below.

Page 14 Lines 4-9 (see above): This guidance statement indicates the "key element" is the 72-hour period from the discovery of an off-normal condition and the resulting change in power. This is also reflected in the Definition of Terms on Page 13 Lines 25-31. This guidance is considered to mean that identification of the off-normal condition was established when the RFP degraded seals were identified and the approved ODMI was in effect. The point when the degraded seal began to exhibit signs of steam is not considered to have been a new off-normal condition, since this was a predefined trigger point established in the ODMI to monitor the degraded seals.

Page 13 Lines 25-31, **Page 15 Lines 36-43** and **Page 17 Lines 24-29** (see above): These guidance statements provide specific criteria to be considered when determining if the power change should be excluded from counting, interpreted as follows:

- <u>Condition is identified that is slowly degrading</u>. The degraded RFP seals were identified and being monitored in accordance with the ODMI for many days prior to reaching the ODMI trigger point that required a power reduction. The point at which the seal reached an ODMI trigger point is not considered a new condition.
- <u>Licensee prepares plans to reduce power when the condition reaches a predefined limit</u>. An ODMI was approved and in place and the degraded RFP seals were being closely monitored weeks before a trigger point was reached that required the RFP to be removed from service. As planned, when Trigger Point 3 was reached, operators methodically lowered reactor power and removed the affected RFP from service using normal operating procedures. Contingency planning included appropriate safety reviews, parts procurement and pre-assembly, work package preparation, and schedules for RFP seal repairs. This is consistent with the guidance on Page 14 Lines 4-9, with respect to the basis for the 72-hour period and the extent of planning required.
- <u>72 hours have elapsed since the condition was first identified</u>. The condition of degraded RFP seals was identified many days prior to the power reduction.

As written, the guidance is interpreted to mean that if the conditions are met, then the power change would not count. The guidance goes on to state that "If however, the condition suddenly degrades beyond the predefined limits and requires rapid response, this situation would count." In plain language, the phrase "If however" is interpreted to mean that this condition would apply if the criteria described in the previous sentences of the respective paragraphs were not met. Therefore, the phrase "suddenly degrades beyond the predefined limits and requires rapid response" should not apply since it is defined as applicable to a condition for which the specific criteria are not met. This is reasonable since the RFP did not suddenly degrade beyond the predefined trigger point established by the ODMI, the condition was being monitored for more than 72 hours prior to the power reduction, and the actions taken were pre-planned in accordance with the ODMI using normal operating procedures. The ODMI was a deliberate, pre-planned response to the degraded condition, in part designed to avoid premature replacement of degraded RFP seals with usable service life remaining, by establishing appropriate trigger points that allowed the affected RFP to be safely removed from service when required.

The degraded RFP seals were identified, and plans prepared recognizing the need to reduce power when the leakage reached predefined limits established by the ODMI trigger points. Increased leak rate was not a different condition but a continuing degradation of the previous off-normal condition. The off-normal condition is considered excessive seal leakage, and includes steaming from a seal. Therefore, reaching a trigger point did not establish a new condition or time of discovery, and the actions taken were not a rapid response, having been established more than 72 hours in advance.

Seal leakage was being monitored for many weeks prior to the downpower. The exact time that a trigger point would be reached could not be known in advance. However, the entire organization understood the direction provided by the ODMI and the required actions. This resulted in a minimal delay prior to initiating the power reduction upon reaching the trigger point.

- The operating crews covered the ODMI in shift briefs. The degraded seal on RFP "A" reaching Trigger Point 3 was not a surprise to the operating crew, since the operating crews had covered the ODMI in shift briefs. During the nearly 10 hours after Trigger Point 2 was reached and before reaching Trigger Point 3, the operating crews reviewed the normal operating procedures for the anticipated power reduction.

- Operators reduced power by reducing core flow and inserting control rods using the Rapid Shutdown Sequence, as directed by normal operating procedure OP 0105, "Reactor Operations." VY procedure EGOP-2404, "Determination and Implementation of Rod Movement Sequences," discusses two sequences that can be used by Operations during a controlled shutdown or power reduction. One sequence follows the rod withdrawal sequence inserting the rods in the reverse order starting with the last group withdrawn and working backward through the sequence. The other sequence is the Rapid Shutdown Sequence which reduces the number of rod manipulations by moving rods more than one notch at a time, thus reducing the amount of time required to shut down or reduce power. The Rapid Shutdown Sequence has no adverse impact on plant operations or the fuel. During the power reduction, the reactor engineer was present in the control room as required by procedure.

The ODMI did not specify a target power reduction, since anticipated actions to be taken were according to the plant's normal operating procedures. That is, the planned power reduction was the power level required to be reached prior to securing a RFP. Normal operating procedures require reactor power to be approximately 40% to secure a second RFP. The ODMI accommodated the possibility that both the "A" and "B" RFP seals could require repairs at the same time. Anticipation of similar degradation is reasonable, since the seals on the RFP pumps were replaced during the previous refueling outage, and had experienced about equal run time.

As part of implementing the ODMI, the station evaluated the risk and elected to remove the RFP from service when the anticipated trigger point was reached. The condition of steaming from the seal did not result in the RFP being incapable of performing its function. The ODMI trigger points and actions allowed the RFP to be removed from service in a controlled manner, without a RFP trip and without allowing excessive leakage or steaming from the seal to adversely affect the surrounding area. At the time the RFP was removed from service, it was still performing its function regardless of the self-imposed seal leakage criteria set by the ODMI directing that the RFP be removed from service. Therefore, no safety function was challenged.

The ODMI provided guidance for pre-approved contingency actions to be taken when established limits for seal leakage were exceeded, using normal operating procedures. Without the ODMI in place, the normal operating procedure guidance alone would not be considered sufficient to meet the criteria for a planned power reduction.

Note: Specific values such as reactor power levels and times as described above are approximated.

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

NRC RESIDENT COMMENTS:

See attached pages.

Potentially relevant existing FAQ numbers:

Recently approved IE03 FAQ 13-02 (Susquehanna, 10/23/13) and IE03 FAQ 13-05 (Oyster Creek, 4/2/14) were reviewed, and were determined to not be directly applicable to the question of interpretation posed by this FAQ.

The following archived FAQs were also reviewed:

237 – The issue is substantially similar and involved a slow leak on a feedwater pump. However, there is no mention of contingency actions similar to the ODMI for VY, and the actions taken by VY are not considered to have been outside the contingency planning in place.

343 – The issue is substantially similar and involved degraded RFP seals. However the disposition did not clarify the basis for stating that the condition suddenly degraded beyond predefined limits and that rapid action was required, and did not appear to clarify how the above guidance should be interpreted. This FAQ also references three others, in particular 277 which had concluded that increased leak rate was not a different condition but a continuing degradation of the previous off-normal condition.

<u>Response Section</u>

Proposed Resolution of FAQ: The proposed resolution to this event is to conclude that the power changes should not be reported as unplanned.

If appropriate, provide proposed rewording of guidance for inclusion in next revision: Not applicable

PRA update required to implement this FAQ? No

MSPI Basis Document update required to implement this FAQ? No

The NRC resident inspectors reviewed and concurred with the sequence of events as described. To facilitate understanding the trends involved, the residents compiled the recorded leak rate data and graphed the data as shown on the following page. The resident inspectors considered FAQ 343 and applied the applicable guidance using the following principles in order to categorize the event.

For the purposes of the PI, being planned does not just include having the sequence, instructions, and work orders involved to deal with a particular concern or condition. Planned versus unplanned also requires consideration of specific plant conditions for that particular point in time and therefore includes an actual intended decision to implement a downpower at an approximately expected or predicted time 72 hours hence. As such, downpowers for which work orders and schedules were previously prepared to deal with conditions, even when scheduled as contingencies, do not necessarily represent planned downpowers absent actual intent to downpower 72 hours in advance, based on actual, known conditions understood to be present at that point in time.

For conditions being tracked and trended after being initially identified greater than 72 hours in advance, the applicable guidance states that a known condition that suddenly degrades beyond the predefined limits requiring rapid response counts against the PI. The guidance does not, however, quantify sudden degradation and rapid response nor does it describe the underlying basis. Given that the PI designates a 72 hour time period following discovery of an off-normal condition regardless of the actual extent of planning required, the resident inspectors applied the same standard against the developed trend in this case. Therefore, the two possible choices are:

- The trended condition alerted the station of the need to actually downpower at a time at least 72 hours in the future. The condition was slowly degrading not requiring a rapid response such that sufficient time existed to prepare the station and schedule the downpower considering plant conditions at that specific point in time. The power change does not count.
- The trended condition did not alert the station of the need to actually downpower at a time at least 72 hours in the future. The condition suddenly degraded and required a rapid response such that sufficient time did not exist to prepare the station and schedule the downpower considering plant conditions at that specific point in time. The power change does count against the PI.

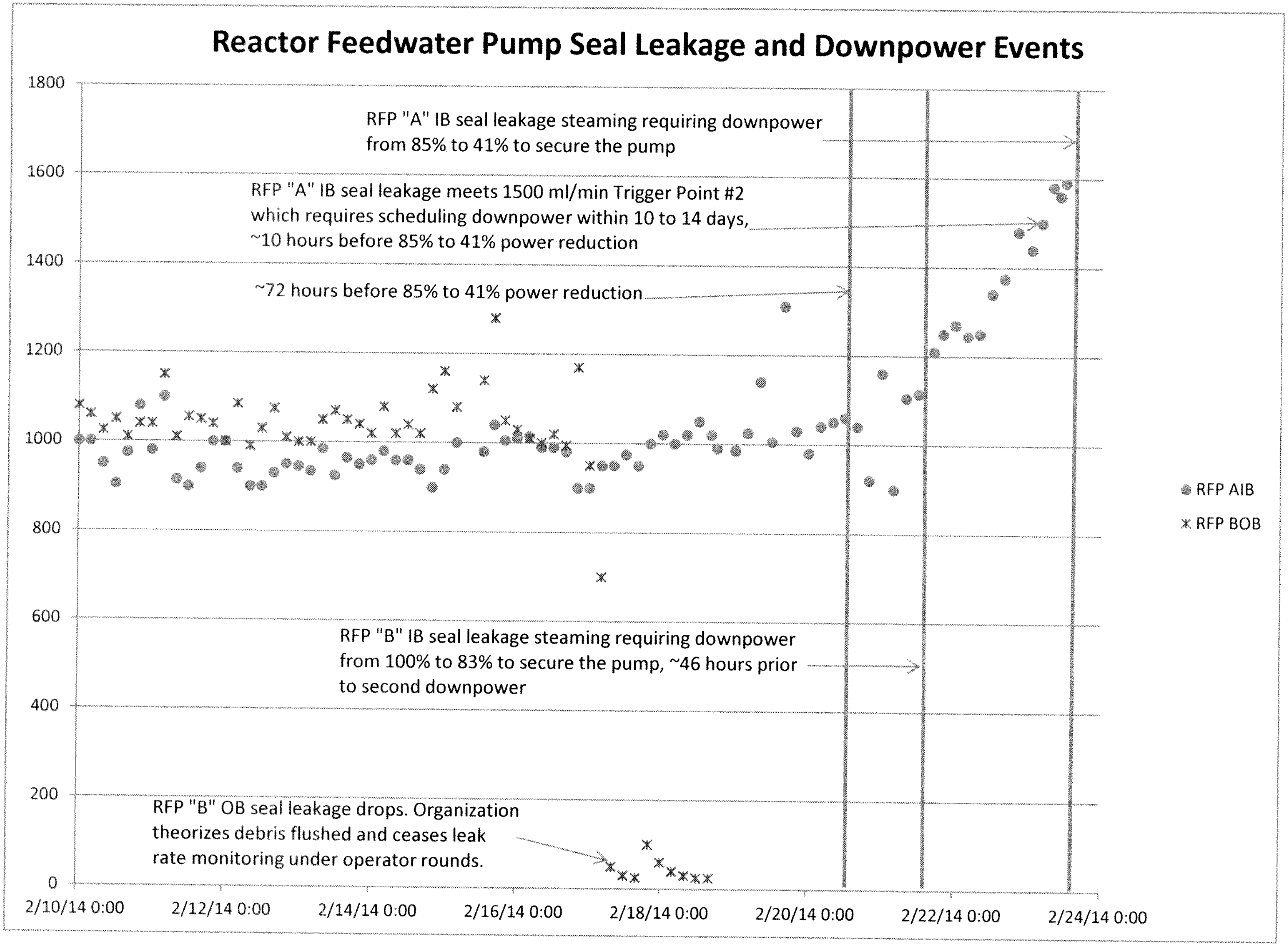
Therefore, in considering the event, the inspectors noted the following:

- 72 hours prior to the second downpower for the second feedwater pump, the monitored trend did not anticipate a need for either feedwater pump to be removed from service and an actual intent to conduct a downpower at that time did not exist.
- The prepared plans and work orders did not anticipate removing two feedwater pumps from service simultaneously.
- The root cause evaluation identified a contributing cause for the "A" feedwater pump inboard seal failure of "hydraulic disturbances on an already degraded seal," noting that taking the "B" feedwater pump out of service resulted in hydraulic disturbances.

- After securing the “A” feedwater pump, the pump lube oil system was found to be excessively fouled with water from the steaming seal. As a result, additional inspections, flushing of the pump lube oil system, and replacement of the lube oil were required which were not originally anticipated and planned. In addition, the pace of the downpower as performed was not rapid enough in order to prevent contamination of the oil.
- The seal leakage trends involved were intended to provide sufficient monitoring such that trigger point #2 would require scheduling a downpower within 10 to 14 days upon being reached. In contrast, feedwater pump “B” inboard seal began emitting continuous steam without first reaching Trigger #2, and feedwater pump “A” inboard seal reached Trigger #2 only 10 hours before emitting continuous steam.
- Given continuous steaming from the seals, there was a need and requirement to remove the feedwater pumps from service promptly. The station no longer had scheduling flexibility in order to deal with the issues even if other equipment concerns or issues had existed at that time. In other words, under other plant conditions safety functions could have been challenged due to the emergent nature of the failing seals and the need for a reactive response.
- The normal operating procedure required reducing power in accordance with the Reactor Engineering Maneuver Plan, and if a Reactor Engineering Maneuver Plan was not available, to reduce power in given steps that included use of the control rod Rapid Shutdown Sequence. For this downpower, a Reactor Engineering Maneuver Plan was not available, and the Rapid Shutdown Sequence was used.

The NRC resident inspectors recommend considered discussion of this FAQ within the overall context of the PI and monitoring of events involving reactive versus proactive downpowers and recommend adding specific criteria for classifying slowly degrading conditions versus conditions that suddenly degrade and require rapid response. The enhanced guidance to be incorporated could take the form of any of the following, for example:

- Apply the 72 hour conservative interpretation described above for classifying slow versus sudden degradation of monitored conditions.
- Apply a more relaxed 24 hour criterion for trending to anticipate the need to implement the anticipated downpower to discriminate between slow versus sudden degradations and rapid response.
- Narrowly define sudden degradation and rapid response to include only those events that require rates of power reduction beyond normal operating procedure parameters.



Reactor Feedwater Pump Seal Leakage and Downpower Events
1800
1600
1400
1200
1000
800
600
400
200
0
2/10/14 0:00
2/12/14 0:00
2/14/14 0:00
2/16/14 0:00
2/18/14 0:00
2/20/14 0:00
2/22/14 0:00
2/24/14 0:00
RFP AIB
RFP BOB
RFP "A" IB seal leakage steaming requiring downpower from 85% to 41% to secure the pump
RFP "A" IB seal leakage meets 1500 ml/min Trigger Point #2 which requires scheduling downpower within 10 to 14 days, ~10 hours before 85% to 41% power reduction
~72 hours before 85% to 41% power reduction
RFP "B" IB seal leakage steaming requiring downpower from 100% to 83% to secure the pump, ~46 hours prior to second downpower
RFP "B" OB seal leakage drops. Organization theorizes debris flushed and ceases leak rate monitoring under operator rounds.

FAQ 14-06: VY Unplanned Power Changes

NRC Response

As the staff and industry representatives acknowledged during the October 22, 2014, ROP public meeting (Agencywide Document Access and Management System (ADAMS) Accession No. ML14314A322), the ROP Working Group might not be able to resolve this FAQ prior to the Vermont Yankee's expected transition to decommissioning. The staff recommends withdrawing this FAQ, given that a tentative resolution to this FAQ has not been achieved at this time.

The staff recognizes that this FAQ provides an opportunity to explore the need for clarifying the terms "sudden degradation" and "rapid response" under the Unplanned Power Changes per 7,000 Critical Hours performance indicator guidance in NEI 99-02 Rev. 7. The staff encourages industry representatives to provide a generic FAQ to the ROP WG to clarify these terms, if such clarification is warranted to evaluate similar events in the future.

FAQ 14-07 (Proposed)
Point Beach Alert & Notification System

Plant: Point Beach 1 and Point Beach 2
Date of Event: November 1, 2014
Submittal Date: October 10, 2014
Licensee Contact: Gerard D. Strharsky **Tel/email:** 920-755-6557/gerard.strharsky@nee.com
NRC Contact: James Beavers **Tel/email:** 630-829-9760

Performance Indicator: Alert and Notification System Reliability (EP03)

Site-Specific FAQ (Appendix D)? Yes, Appendix D page D-1

FAQ requested to become effective: At the beginning of the first full reporting period after Point Beach assumes full responsibility for all sirens in the overlap area and ~~the FEMA REP-10 is approved~~ ANS design change has received FEMA's approval.

Question Section

NEI 99-02 Guidance needing interpretation (include page and line citation):
Page D-1, Lines 20-22:

20 Some provisions in NEI 99-02 may differ from the design, programs, or procedures of a particular
21 plant. Examples include (1) the overlapping Emergency Planning Zones at Kewaunee and Point
22 Beach and (2) actions to address storm-driven debris on intake structures.

Page D-1, Lines 27-42:

27 **Kewaunee and Point Beach**
28
29 Issue: The Kewaunee and Point Beach sites have overlapping Emergency Planning Zones (EPZ).
30 We report siren data to the Federal Emergency Management Agency (FEMA) grouped by criterion
31 other than entire EPZs (such as along county lines). May we report siren data for the PIs in the
32 same fashion to eliminate confusion and prevent 'double reporting' of sirens that exist in both
33 EPZs? Kewaunee and Point Beach share a portion of EPZs and responsibility for the sirens has
34 been divided along the county line that runs between the two sites. FEMA has accepted this, and
35 so far the NRC has accepted this informally.
36
37 Resolution: The purpose of the Alert and Notification System Reliability PI is to indicate the
38 licensee's ability to maintain risk-significant EP equipment. In this unique case, each neighboring
39 plant maintains sirens in a different county. Although the EPZ is shared, the plants do not share
40 the same site. In this case, it is appropriate for the licensees to report the sirens they are
41 responsible for. The NRC Web site display of information for each site will contain a footnote
42 recognizing this shared EPZ responsibility.

Event or circumstances requiring guidance interpretation:
Point Beach Nuclear Plant (PBNP) has concluded negotiations for taking responsibility of siren maintenance and operation from Kewaunee for the remaining sirens in the area of overlap of Emergency Planning Zones between the respective sites. That transition is expected to occur sometime after November 1, 2014, with FEMA formal approval shortly thereafter. Consequently, the site-specific FAQ documented in NEI 99-02, Rev 7, Page D-1, Lines 27 through 42, will no longer apply after that transition occurs.

PBNP has historically, obtained ANS siren performance and maintenance records and data from KPS for the purpose of monitoring and recording all required information related to overlapping siren performance. As a result of previously approved FAQ 13-04, Point Beach had also been recording the performance information related to those sirens in the comments section of CDE.

If licensee and NRC resident/region do not agree on the facts and circumstances explain
The content of this FAQ has been reviewed with NRC Region III Emergency Preparedness Inspector, who indicated that he concurs with the facts and circumstances as provided.

Potentially relevant existing FAQ numbers
FAQ 13-04. (The text of Appendix D first appears in NEI 99-02, Revision 1, published April 2001.)

Response Section

Proposed Resolution of FAQ
Beginning with the first full quarter in which Point Beach is responsible for maintenance of the sirens formerly in the overlap area and FEMA approves the updated ~~REP-10~~ANS design, the site specific FAQ governing reporting of the shared sirens between Point Beach and Kewaunee should be rescinded.

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

- Revise Page D-1, Lines 21-22, as follows:

Some provisions in NEI 99-02 may differ from the design, programs, or procedures of a particular plant. For ~~E~~example~~s~~, ~~include (1) the overlapping Emergency Planning Zones at Kewaunee and Point Beach and (2)~~ actions to address storm-driven debris on intake structures.

- Delete section of NEI 99-02 discussing the site specific condition (Page D-1, Lines 27 through 42) in its entirety, as it will no longer be applicable.

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

PRA update required to implement this FAQ? No
MSPI Basis Document update required to implement this FAQ? No

NRC Response
This FAQ follows up to FAQ 13-04, Point Beach Alert and Notification System (FAQ 13-04 is available through Agencywide Document Access and Management System (ADAMS) Accession No. ML14107A056.) The resolution of FAQ 13-04 recommended revising NEI 99-02 Appendix D, "Plant Specific Design Issues," once PBNP becomes responsible for the sirens located in Kewaunee County, to remove the "Kewaunee and Point Beach" plant specific design issue. This FAQ requests the removal of such section from NEI 99-02.

The staff agrees with the proposed resolution and effective date for the FAQ. ~~The staff also agrees that the FAQ will become effective at the beginning of the first full reporting period after Point Beach assumes full responsibility for all sirens in the overlap area.~~

NEI 99-02 FAQ 14-XX (Proposed)
Prairie Island MSPI

Plant: Prairie Island Nuclear Generating Station (PINGP) Unit 1

Date of Event: June 23, 2014

Submittal Date: November 18, 2014

Licensee Contact: Laura Jean Noonan

Tel/email: 651-267-6449 / Laura.Jean.Noonan@xenuclear.com

NRC Contact: Karla Stoedter

Tel/email: 651-388-1121 X4219

Performance Indicator:

MS06 – Emergency AC Power Systems

Site-Specific FAQ (see Appendix D)? No

FAQ to become effective: When approved

<u>Question Section</u>

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

Pg F-6 Lines 14-21:

Return to Service: Return to service is the transition from unavailable to available. A train/segment is "returned to service" when the following conditions are met: clearance tags have been removed, the train/segment has been aligned and prepared for operation, (e.g., valve line-up complete, system filled and vented), further adjustment of associated equipment is not required or expected as a result of the unavailability period, and operators concur that the train/segment is able to perform its expected functions. For standby equipment, automatic functions are aligned or can be promptly restored by an operator consistent with the requirements for crediting operator recovery stated later in this section.

Pg F-27 Lines 14-20:

***Emergency power generator failure to load/run**:* Given that the emergency power generator has successfully started and the output breaker has received a signal to close, a failure of the generator output breaker to close or a failure to run/operate for one hour after breaker closure. The emergency power generator does not have to be fully loaded to count the failure. Failure to load/run also includes failures of the emergency power generator output breaker to re-close following a grid disturbance if the emergency power generator was running paralleled to the grid, provided breaker closure is required by plant design.

Pg F-28 Lines 39-46, Pg F-29 Lines 1-7

Human errors/component trips, inadvertent actuations or unplanned unavailability introduced as part of a test or maintenance activity are not indicative of the reliability of the equipment had the activity not been performed, and should NOT be counted as failures as long as they are immediately revealed and promptly reported to the control room.

This applies to human errors which result in tripping an MSPI component that:

1. Occur while the MSPI train/segment is considered available;
2. Do not result in actual equipment damage;
3. Are immediately revealed through clear and unambiguous indication;
4. Are promptly reported to the control room without delay prior to the performance of corrective actions, and;
5. Are clearly associated with a test or maintenance activity such that the failure sequence would not have occurred and cannot occur if the test or maintenance activity was not being performed.

Pg F-48 Lines 23-26

An EDG is not considered to have failed due to any of the following events:

- spurious operation of a trip that would be bypassed in a loss of offsite power event
- malfunction of equipment that is not required to operate during a loss of offsite power event (e.g., circuitry used to synchronize the EDG with off-site power sources)

Event or circumstances requiring guidance interpretation:

On June 23, 2014, a failed relay associated with a 345kV/161kV transformer (TR10) in the Prairie Island Nuclear Generating Plant (PINGP) switchyard resulted in the load tap changer receiving a signal to move to the lowest tap setting. This created a low voltage condition in the 161kV PINGP bus. As a result Engineered Safety Feature (ESF) Bus 15 was declared inoperable. The other ESF bus, Bus 16, was being energized from a different offsite source and did not experience a low voltage condition. Eventually the 161kV bus voltage dropped to less than 155kV which resulted in an undervoltage condition on Bus 15 and an auto start of Emergency Diesel Generator (EDG) D1 which then powered the loads on Bus 15.

The Control Room operators subsequently paralleled a different offsite source (CT11) with D1 in order to transfer the Bus 15 loads using procedure 1C20.7. This procedure includes a caution against allowing the load on D1 to drop to less than 100 kW to prevent motorizing the generator. This evolution is a restoration activity that procedurally requires declaring the diesel generator inoperable and unavailable.

D1 subsequently experienced a reverse power condition resulting in a trip and reverse power (86 relay) lockout. The lockout was caused by a reverse-power condition during the supply-source transfer of Bus 15 from D1 to CT11.

The trip of D1 was reported as an MSPI EAC load/run failure in the 2nd quarter of 2014; however, PINGP is seeking to retract the failure.

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

The NRC Resident agrees with the description of the event. However, it is not clear from NEI 99-02 whether this restoration activity would meet the definition of maintenance, or whether the event constitutes an MSPI failure.

Potentially relevant FAQs: None

Response Section

Proposed Resolution of FAQ:

The trip and reverse power lockout of D1 does not count as an MSPI failure.

Per the Prairie Island MSPI Basis Document, Revision 15, the MSPI monitored function for the Emergency AC System is “To provide emergency AC power to risk-significant equipment during loss of AC power conditions.” D1 was fulfilling this function by powering the loads on Bus 15 in response to the undervoltage condition.

The evolution of paralleling an emergency diesel generator to an offsite power source is considered a restoration activity by the site. For D1, this requires declaring the diesel inoperable and unavailable. Operator action is required to parallel to an alternate source, dial in droop on D1, and to open the emergency diesel generator output breaker.

The reverse power logic is a protective feature for when D1 is paralleled to a second power source. Although the reverse power trip and lockout logic are not bypassed during a loss of offsite power event, a valid reverse power condition is not possible when D1 is performing its monitored function.

The lockout condition was not indicative of the reliability of the equipment, and should not be counted as an MSPI failure. No equipment damage occurred. The lockout condition was immediately identified in the control room and corrected prior to D1 being returned to operable status.

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

> Pg F-28 beginning on line 39 should be clarified to reflect that events which are caused by human error that are not indicative of the reliability of the equipment should not be counted as failures:
>
> > Human errors/component trips, inadvertent actuations or unplanned unavailability which are not indicative of the reliability of the equipment had the activity not been performed, should NOT be counted as failures as long as they are immediately revealed and promptly reported to the control room.
> >
> > This applies to human errors which result in tripping an MSPI component whether or not the MSPI train/segment is considered available that:
> >
> > 1. Do not result in actual equipment damage;
> > 2. Are immediately revealed through clear and unambiguous indication;

3. Are promptly reported to the control room without delay prior to the performance of corrective actions, and;
4. Are clearly associated with an activity such that the failure sequence would not have occurred and cannot occur if the activity was not being performed.

Unavailability should be counted from the time of the event until the equipment is returned to service, and classified as unplanned unless provisions of *Counting Unavailability when Planned and Unplanned Maintenance are Performed in the Same Work Window* apply.

Latent failures (failures that existed prior to the maintenance) that are discovered as part of maintenance or test activity are considered failures.

PRA update required to implement this FAQ?

No

MSPI Basis Document update required to implement this FAQ?

No