UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

June 5, 2000

MEMORANDUM TO: Michael R. Johnson, Section Chief
Inspection Program Branch
Division of Inspection Program Management

FROM: August K. Spector
Inspection Program Branch
Division of Inspection Program Management

SUBJECT: REACTOR OVERSIGHT PROCESS TO DISCUSS INITIAL REACTOR OVERSIGHT PROCESS IMPLEMENTATION PUBLIC MEETING MAY 2, 2000

The NRC conducted a public meeting on May 2, 2000, to discuss initial implementation at the Reactor Oversight Process. The meeting was held at the Nuclear Regulatory Commission, One White Flint North, Rockville, MD. A list of participants, the agenda, and handouts distributed are attached.

Attachments:
1. List of Participants
2. Agenda and Meeting Notes
3. NEI 99-02 Rev OCI
4. Frequently Asked Questions
5. Summary of Meeting on Cross Cutting Issues on April 5, 2000

Attendees List

NAME	AFFILIATION
A. K. Krainik	APS
John Butler	NEI
Steve Floyd	NEI
Tom Houghton	NEI
Brian Sharrow	Northeast Utilities
Bill Watson	Northeast Utilities
Michael J. Maley	NRC
Mary Ferdig	Benedictine University
Pat Loftus	ComEd
Cornelius Holden	NRC
John Thompson	NRC
Dennis Hassler	PSEG
Daniel Robinson	NPPD
Wade Warren	SNC
Kevin Borton	PECO Energy
Donna Alexander	CP&L
Don Hickman	NRC
Alan Madison	NRC
August Spector	NRC
David C. Tubbs	MidAmerican

Public Meeting
Agenda and Meeting Notes
May 2, 2000

1. Initiating Event Performance Indicator NEI Task Force -- update

2. Performance Indicators related to Combustion Engineering Plants -- update and approval (see Attachment 3)

   NEI distributed NEI 99-02 Rev. 0 C1. Agreed to include this minor revision to NEI 99-02, which deals with Combustion Engineering Plant PI's, as a Frequently Asked Question rather than as a page change to NEI 99-02 Rev. 0. At the time NEI 99-02 has its major update/revision appropriate FAQ's will be included.

3. Frequently Asked Questions -- discussion and update (see Attachment 4)

   FAQ Log 6 answers were approved with minor changes. To be posted on the NEI and NRC web sites.

   FAQ Log 7 items 1, 10, and 11 were placed on hold for further discussion. Items 2,3,9,14 were approved with minor changes. These to be posted on the NEI and NRC web sites.

4. Cross Cutting Working Group -- report and update (see Attachment 5)

   Summary of the Cross cutting Working Group meeting held by NRC on April 5, 2000 was distributed. NRC requested feedback and input for future consideration by the working group. NRC is planning to create a stakeholder "work group" to provide assistance regarding cross cutting issues. NRC requested that stakeholders provide potential names for working group membership.

5. Fault Exposure Hours PI -- discussion

   Recommended by NEI to use in SDP rather than as Performance indicator. Agreed to discuss during a future meeting.

Next meeting May 24, 2000

Tentative agenda items are:

a. Discussion of cross cutting issues and stakeholder feedback.
b. Discussion of initiating event cornerstone PI
c. Discussion of reliability performance indicators
d. Discussion and update of FAQ's.

Attachment 2

Four trains should be monitored as follows:

Train 1 (recirculation mode)
Consisting of the containment recirculation spray pump associated MOVS and the required recirculation spray pump heat exchanger and MOVS.

Train 2 (recirculation mode)
Consisting of containment recirculation spray pump associated MOVS and the required recirculation spray pump heat exchanger, and MOVS.

Train 3 (shutdown cooling mode)
Consisting of the "A" RHR pump, associated MOVS and heat exchanger.

Train 4 (shutdown cooling mode)
Consisting of the "B" RHR pump, associated MOVS and heat exchanger.

ANO-2, Calvert Cliffs, Fort Calhoun, Millstone 2, Pallisades, Palo Verde, San Onofre, St. Lucie, and Waterford 3

Issue: The Safety System Unavailability Performance Indicator for PWR RHR monitors:

- **The ability of the RHR system to take a suction from the containment sump, cool the fluid, and inject at low pressure into the RCS, and**
- **The ability of the RHR system to remove decay heat from the reactor during normal shutdown for refueling and maintenance.**

CE ECCS designs differ from the RHR description and typical figures in NEI 99-02. CE designs run all ECCS pumps during the injection phase (Containment Spray (CS), High Pressure Safety Injection (HPSI), and Low Pressure Safety Injection (LPSI)), and on Recirculation Actuation Signal (RAS), the LPSI pumps are automatically shutdown, and the suction of the HPSI and CS pumps is shifted to the containment sump. The HPSI pumps then provide the recirculation phase core injection, and the CS pumps by drawing inventory out of the sump, cooling it in heat exchangers, and spraying the cooled water into containment, support the core injection inventory cooling. (Figures D.1 and D.2 show generic schematics.) How should CE designs report the RHR SSU Performance Indicator?

Resolution:
For the first function: "The ability of the RHR system to take a suction from the containment sump, cool the fluid, and inject at low pressure into the RCS."

The CE plant design uses HPSI to "take a suction from the sump", CS to "cool the fluid", and HPSI to "inject at low pressure into the RCS". Due to these design differences, CE plants with this design should monitor this function in the following manner.

Attachment 3

The HPSI pumps and their suction valves are already monitored under the HPSI function, and no monitoring under the RHR PI is necessary or required.

The two containment spray pumps and associated coolers should be counted as two trains of RHR providing the post accident recirculation cooling.

For the second function: "The ability of the RHR system to remove decay heat from the reactor during normal shutdown for refueling and maintenance."

The CE plant design uses LPSI pumps to pump the water from the RCS, through the SDC heat exchangers, and back to the RCS. Due to this CE design difference, the SDC system should be counted as two trains of RHR providing the decay heat removal function.

Therefore, for the CE designed plants four trains should be monitored, when the particular affected function is required by Technical Specifications, as follows:

<u>Train 1 (recirculation mode)</u>
Consisting of the "A" containment spray pump, the required spray pump heat exchanger and associated flow path valves.

<u>Train 2 (recirculation mode)</u>
Consisting of the "B" containment spray pump, the required spray pump heat exchanger and associated flow path valves.

<u>Train 3 (shutdown cooling mode)</u>
Consisting of the "A" SDC pump, associated flow path valves and heat exchanger.

<u>Train 4 (shutdown cooling mode)</u>
Consisting of the "B" SDC pump, associated flow path valves and heat exchanger.

Note that required hours and unavailable hours will be determined by technical specification requirements, not "default hours."

Reporting of RHR data should follow this guidance beginning with the second quarter 2000 data submittal. Historical data was originally reported as two trains. A change report must be submitted to provide historical data for four trains. This can be accomplished in either of two ways:

1. **Maintain Train 1 and Train 2 historical data as is. For Train 3 and 4, repeat Train 1 and Train 2 data.**

2. **Recalculate and revise all historical data using this guidance.**

Provide comments with the change report to identify the manner in which the historical data has been revised.

Figure D.1

SHUT DOWN COOLING SYSTEM

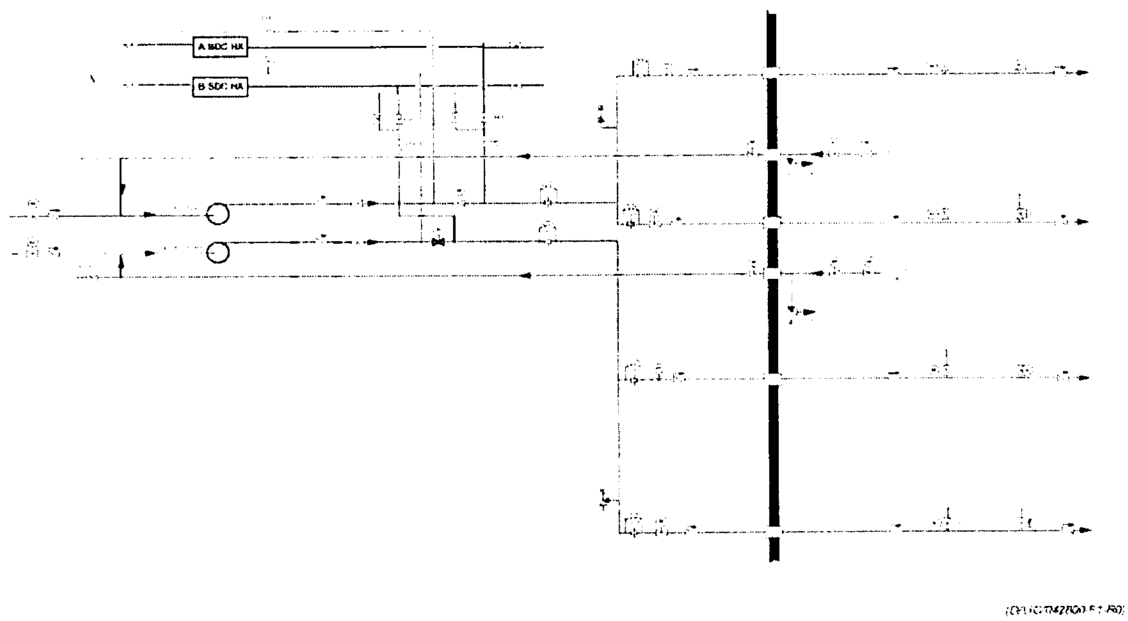
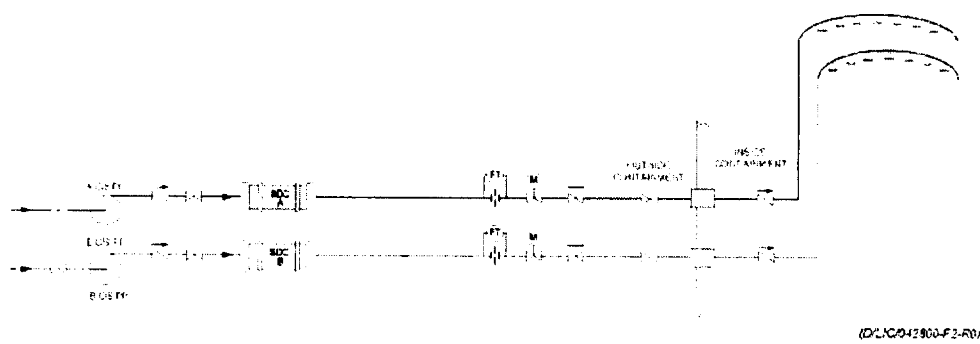


Figure D.2

CONTAINMENT SPRAY SYSTEM



Draft 5/1/2000 4:59 PM
FAQ Log 6

Temp. No.	PI	Question	Proposed Answer	Effective Date
1	PP01	Variable Normalization Factor During steady state operations our site has one access portal open for personnel to enter the protected area. During an outage we open a second access portal. The change in protected area barrier configuration affects the number of zones that are used. The result is we have a 1.9 normalization factor during steady state, and 1.95 during an outage. What value of normalization factor should we report for quarters that include an outage?	A prorated normalization factor that addresses periods when the second access portal is open should be reported.Add a note in the comment field describing situation.	5/2/00
2	PP01	NEI 99-02 under the Preventive maintenance section indicates that during preventive maintenance or testing, cameras that do not function properly and can be compensated for by means other than posting an officer, no compensatory man-hours are counted. Does this exclusion only apply to camera events discovered during the above mentioned times or can this exclusion be applied to any time a camera can be compensated for by means other than posting an officer?	The PI counts compensatory man-hours. Any compensatory actions other than posting a security officer (e.g., use of alternate equipment) are not counted. *Note: If a security officer is normally posted for a zone (as a normal post, not compensating), and he is now told to comp a zone because cameras are not working, these hours would count.)*	5/2/00
4	PP01	Is the tamper detection system considered part of the IDS? For example, if the tamper detection system is being monitored for compensatory measures, but the IDS is properly functioning, do licensees need to count these compensatory hours?	Not if IDS is functioning as intended.	5/2/00
9	MS04	Can a Spent Fuel Cooling train be considered an installed spare of Shutdown Cooling under certain conditions? If yes, should unavailable hours be counted during a planned removal from service of the entire Shutdown Cooling System, if it has been demonstrated that a single SFC train will meet the requirements for an installed spare of the shutdown cooling function, and two SFC trains are currently operable? NEI 99-02, states that an "installed spare" is "a component (or set of components) that is used as a replacement for other equipment to allow for the removal of equipment from service for preventive or corrective maintenance without incurring a limited condition for operation (where applicable) or violating the single failure criteria. To be an "installed spare," a component must not be required in the	*The Spent Fuel Cooling train is not an installed spare. However, if the Spent Fuel Cooling system is an NRC approved alternate means of removing decay heat, the hours do not have to count.* (Refer to p.32 lines 13-18)	5/2/00

Attachment #

Temp. No.	PI	Question	Proposed Answer	Effective Date
		design basis safety analysis for the system to perform its safety function." Using the above definition, it would appear a Spent Fuel Cooling System train could be considered an installed spare of the shutdown cooling function under certain conditions: no design basis safety analysis requirement, a connection between the spent fuel pool and reactor vessel, and analysis indicating that under the current conditions the train is adequate to offset the combined vessel and fuel pool decay heat load. FAQ 17 appears to support the interpretation that SFC can be an installed spare of shutdown cooling under certain conditions. NEI 99-02 goes on to say that "those portions of the Shutdown Cooling System associated with one heat exchanger flow path can be taken out of service without incurring planned or unplanned unavailable hours provided the other heat exchanger flow path is available (including at least one pump) and an alternate, NRC approved means of removing core decay heat is available." In the case cited above, each SFC train has taken the place of a Shutdown Cooling System train, as an installed spare. Each SFC train can maintain the core decay heat load within the temperature limits set by the plant's design basis. Therefore, there continues to be a heat exchanger flow path, and an alternate, closed-cycle, forced means of removing core decay heat. Thus, it would appear no unavailable hours need be incurred.		
10	MS01 - MS04	NEI 99-02 does not adequately address how to evaluate unplanned unavailable hours for situations where support systems are not immediately required but are required for long term operation. For example: One of our plants has a situation where a breaker for some DG support systems, specifically, fuel transfer to the DG day tank (4 hour capacity), and room cooling (during the winter) was found to	No. No credit may be taken for operator actions for planned or unplanned unavailable hours other than testing as discussed on page 26 of NEI 99-02.	5/2/00

Temp. No.	PI	Question	Proposed Answer	Effective Date
		be inoperable. For this situation, the DG would have started and performed it's intended function for a length of time (probably 4 hours). Also, control room alarms and/or local log recording would have noted the deficient condition, and administrative controls would have provided for restoration of the system without losing the Diesel Generator safety function. Engineering analysis can determine how long the DG would operate compared to the expected response by the plant for restoration of the support systems. However, NEI 99-02 does not address alarms and operator actions for this type of situation. For this type of situation, may credit be taken for analysis involving alarms and actions?		
11	IE03	Concerning Unplanned Power Changes per 7,000 Critical Hours, does the 72 hour period apply to situations where power reductions are required to conduct expected rod pattern adjustments? A specific example involves a reactor start-up and power ascension following a scram. It is expected that the subsequent startup will probably require a rod pattern adjustment after achieving 100% power. To conduct the adjustment after achieving 100% power would require a power reduction potentially greater than 20%. If this situation occurs in less than a 72 hour period (time frame from the scram to the > 20% power reduction following return to power operation) does this count as an unplanned power change?	This indicator monitors changes in reactor power that are initiated following the discovery of an off-normal condition. The example described would not be counted in the unplanned power changes indicator provided the condition is expected.	5/2/00
12	MS01 - MS04	Does planned preventive maintenance (PM) or corrective maintenance (CM) on support systems have to be taken as Planned Unavailable Hours for the supported system? Page 22, lines 9 – 33 infers that <u>any</u> PM or CM must be credited as Planned Unavailable hours. One example is a site where there are four EDGs. Each EDG has two approximate 50% fuel oil tanks. The fuel oil tanks are a support system for the EDG. At times, a fuel oil tank is removed from service and drained for cleaning. In this case, the Technical Specification requires the corresponding EDG to be declared Inoperable. However, with one fuel oil tank remaining available, the	Yes. No credit may be taken for operator actions for planned or unplanned unavailable hours other than testing as discussed on page 26 of NEI 99-02.	5/2/00

Temp. No.	PI	Question	Proposed Answer	Effective Date
		EDG will start and has enough fuel to run for over 3 days with no operator action required (Note: the mission time is 7 days). In addition, plans are in place in emergency scenarios for the delivery of fuel oil. Another example for the same configuration, each fuel oil storage tank has a separate fuel oil transfer pump. At one time, both fuel oil transfer pumps were inoperable to support troubleshooting activities. The EDG day tanks were available and would support EDG start and contain sufficient fuel to run for a few hours. During the troubleshooting activities, work was performed in accordance with a procedure, an operator was stationed locally for restoration, and the restoration steps were non-complicated. For both examples, the EDG will perform its safety function for an ample time following a loss of offsite power with no immediate operator action; does this time have to be counted as unavailable hours for the EDG?		
24	MS01 02, 03, 04	Assume a recirculation spray pump tested poorly and had only previously been tested 2 years ago. Per the NEI 99-02 FAQ I believe I am to go back and revise the fault exposure hours for these quarters. Should I zero out any other unavailability for those months, since the accumulation of unavailability could be greater than the hours required?	Remove the double count by removing the planned and unplanned hours which overlap with the fault exposure hours. Put an explanation in the comment field. If you later remove the fault exposure hours, restore the hours which had been removed.	5/2/00
26		Are Technical Specification required monthly Emergency Diesel Generator surveillance tests counted as unavailability for this PI? Actions to restore the EDGs during surveillance testing could be considered complex. However, it seems unreasonable to count these required surveillance tests as unavailability, considering the fact that the EDG is powering the Engineered Safeguards bus in parallel with the grid for the majority of the test.	Yes.	5/2/00
27		We have not been counting technical specification required Emergency AC System surveillance testing as unavailability for the WANO performance indicators. The testing configuration is not	No, the historical data does not have to be revised. However, data submitted for first quarter 2000 must comply with NEI 99-02.	5/2/00

Temp. No.	PI	Question	Proposed Answer	Effective Date
		automatically overridden by a valid starting signal and the function cannot be immediately restored, either by an operator in the control room or by a dedicated operator stationed locally for that purpose. Does historical data submitted Jan 21, 2000 for Emergency AC System safety system unavailability PI have to be corrected to take into account the additional unavailability?		
30		Do hours associated with EDG improvements (e.g., cooling improvement modifications) have to be counted as unavailable hours if done for EDG improvement and in accordance with the Tech Spec AOT(our AOT is 14 days and in partly risk informed).	Yes.	5/2/00

FAQ LOG 7B
DRAFT
5/2/00

No.	PI	Question	Proposed Answer	Plant/ Company
1.	BI01	In the discussion of RCS Activity, NEI 99-02 states: "This indicator monitors the steady state integrity of the fuel-cladding barrier. Transient spikes in RCS Specific Activity following power changes, shutdowns and scrams may not provide a reliable indication of cladding integrity and should not be included in the monthly maximum for this indicator. " Steady state is not defined.	If steady state is not defined by the licensee, use the definition in INPO96-003 where steady state is defined as continuous operation for at least three days at a power level that does not vary more than ± 5 percent. HOLD FOR NRC REVIEW	PSEG
2.	EP01	During an evaluated scenario, the conditions for a General Emergency (GE) were met based on Plant conditions with three barriers breached. The Emergency Director (ED) failed to recognize the classification conditions had been met within 15 minutes. After the 15 minutes, a release occurred and a dose projection was performed which exceeded levels for a GE. The ED recognized this and a GE was declared based on Radiological Conditions and all required notifications and PARs were completed. (1) Would the first opportunity based on Plant conditions be considered a missed opportunity? (2) Would a second opportunity be allowed based on Radiological conditions? (3) If a second opportunity is not allowed can any credit be taken for successfully completing notification and PAR opportunities based on the second opportunity?	(1) Yes (2) No, because it was not the expected timely and accurate classification opportunity as described in the scenario. In some cases, the scenario controllers may prompt the ED to classify with the same result, a failed opportunity to classify. (3) Yes, credit should be taken for the success or failure of the notification, PAR development and the PAR notification. The subsequent opportunities must not be removed from performance indicator statistics due to poor performance. Additionally, any subsequent PAR changes and the associated notification would also be assessed for timely and accurate completion. Assuming the notifications and the PAR development were timely and accurate, the result is that three out of four opportunities would be reported as successful in performance indicator statistics.	WNP2

Attachment 4

FAQ LOG 7B
DRAFT
5/2/00

No.	**PI**	**Question**	**Proposed Answer**	**Plant/ Company**
3	EP03	For plants where scheduled monthly siren tests are initiated by local or state governments, if a scheduled test is not performed either (intentionally or accidentally), is this considered a failure?	No. For purposes of the NRC PI, missed tests should be considered non-opportunities.	APS
9.	MS01 MS02 MS03 MS04	NEI 99-02 describes the requirements for including testing as planned unavailable hours for safety system unavailability. In this, credit is allowed for a dedicated local operator only if they are positioned at the proper location throughout the duration of the test for the purpose of restoration of the train should a valid demand occur. If the operator dedicated to conducting the test is in the proper location, and has no other duties other than to conduct the test and to restore from the test in the event of a valid demand, then does that operator meet the requirements of this paragraph, or does an additional operator need to be stationed for the sole purpose of restoration.? Note that the operator conducting the test has no other duties when a valid demand is received than to restore the system, and the written guidance for restoration is embedded in the test procedure and in his possession during the testing.	~~Yes~~, provided the additional conditions for exclusion of testing hours, identified on page 26 of NEI 99-02, are met. not clear ~~A single~~ the operator performing the test meets the requirements	WEPCO
10.	MS01 MS02 MS03 MS04	NEI 99-02 allows historical data submitted data to be revised to reflect current guidance if desired. Draft D of NEI 99-02 allowed the submittal of WANO data as reported to WANO. Can major overhaul maintenance unavailable hours be removed from the historical data submitted without additional modifications to the WANO data? Or do other aspects of Revision 0 that are different from WANO reporting have to be considered concurrent with removal of the major overhaul maintenance unavailable hours? For example, in the EAC PI, if it was desired to remove from previously submitted data the overhaul maintenance unavailable hours per revision 0 would I also need to research and modify (if necessary) the historical data to account for limitations of operator action usage that are expected in NRC PI reporting, yet different from WANO reporting?	Hold by NRC Hold by NRC	SNC
11.	MS01 MS02 MS03 MS04	FAQs on Planned Overhaul Hours The concept of not counting major on-line overhaul hours against the SSU performance indicator is sound. It allays a prevalent concern that a licensee could end up with a white indicator, and potentially a degraded cornerstone, primarily due to performing on-line maintenance that is	NOTE: This answer applies to how unavailable hours are counted for PI purposes. It does not establish or recommend any changes in regulatory requirements or licensee maintenance actions. This FAQ is a clarification of original intent. Data previously	Fermi

No.	PI	Question	Proposed Answer	Plant/ Company
		considered in PSA analyses and bounded by the Tech. Spec. AOT, and has been determined to be a good business practice [to reduce outage length, etc.]. To ensure consistency of reporting and inspector oversight, the following issues should be addressed: 1. What defines overhaul versus non-overhaul maintenance? 2. Is application of planned overhaul hours limited to systems for which a risk informed AOT extension has been approved? 3. Is there a limit to the number of planned overhaul outages a licensee can report on a given system / train? 4. Can an overhaul be performed in two segments in separate AOTs during an operating cycle? 5. If an overhaul maintenance interval is scheduled to take 120 hours, but the actual unavailable interval is greater [say 140 hours] but still bounded by T.S. AOT, can the entire interval be designated as planned overhaul hours, or is only the scheduled interval appropriate? 6. Can additional non-overhaul maintenance be performed during a planned overhaul maintenance interval? 7. Can Major rebuild tasks necessitated by an unexpected component failure be counted as overhaul maintenance? [Example: RHR pump wipes a motor bearing during surveillance run. It is decided to pull PM activities ahead to replace the motor with a spare.] Hold by NRC	submitted should be reviewed and revised if necessary. 1. Overhaul tasks are those that require disassembly of major components performed in accordance with an established preventive maintenance program. 2. No, application is for any AOT sufficient to accommodate the overhaul hours. 3. Yes. Once per train per operating cycle. 4. Yes, provided that no more than two segments be used and the total time to perform the overhaul does not exceed one AOT period. 5 If the unavailability is caused by activities designated as planned overhaul maintenance, the hours should not be counted in the unavailability indicator. If the additional unavailability is caused by a failure that would prevent a safety function, the additional hours would be non-overhaul hours, or potential fault exposure hours, and would count toward the indicator. (Also, see footnote 3 page 26 Rev 0.) 6 DISCUSS Yes, as long as the outage duration is bounded by overhaul activities, other maintenance activities may be performed. However, modifications or corrective maintenance to restore system functionality would count. If the overhaul activities are complete, and the outage continues due to non-overhaul activities, the additional hours would be non-overhaul hours and would count toward the indicator. 7. No.	

<table>
<tr><th>No.</th><th>PI</th><th>Question</th><th>Proposed Answer</th><th>Plant/ Company</th></tr>
<tr><td>12.</td><td>MS01
MS02
MS03
MS04</td><td>NEI 99-02 Rev 0 states on Page 33, Lines 30-32 states:

"In some instances, unavailability of a monitored system that is caused by unavailability of a support system used for cooling need not be reported if cooling water from another source can be substituted. Limitations on the source of the cooling water are as follows:"

Further on page 33, lines 44-47 states:

"for emergency generators, cooling water provided by a pump powered by another class lE (safety grade) power source can be substituted, provided a pump is available that will maintain electrical redundancy requirements such that a single failure cannot cause a loss of both emergency generators."

What is meant by water from another source? Does this refer to a redundant source or a diverse cooling water source? An example - for the EDG cooling water:

Is another source meant to be from a source like demineralized water or firewater or, Is a redundant Service Water or Station Auxiliaries Cooling (SACs) pump considered to be another source?</td><td>Licensee Proposed Response:
Service Water or SACS is not considered water from another source.

A water source that is required as backup in case of equipment failure to allow the system to meet redundancy requirements or the single failure criterion is not considered to be cooling water from another source.

Hold</td><td>PSEG</td></tr>
</table>

No.	PI	Question	Proposed Answer	Plant/ Company
14.	MS02	NEI 99-02 contains the guidance for Safety System Unavailability - Planned Unavailable Hours. A system is to be considered unavailable during testing unless specified criteria are met. Monthly HPCI oil samples are taken to monitor the performance of the Turbine and the HPCI Steam Isolation Valve. While taking the oil samples on the HPCI turbine, the Aux. Oil Pump is running and the flow controller is taken to manual and set to minimum flow to prevent an over-speed condition if an initiation signal occurs while the Aux. Oil Pump is running. This monthly oil sample takes about 15 to 30 minutes per month. During this time, the system is declared inoperable and the appropriate Technical Specification actions are entered. If a HPCI initiation signal were received, HPCI will automatically start. The control room operator will manually, with the HPCI flow controller, raise HPCI turbine speed and establish injection flow at 5600 gpm as directed by procedure. This manual action is unlike the automatic response. A fully automatic response would control the transient turbine acceleration and ramp open the steam stop valve and control the response of the governor control valve such that 5600 gpm is achieved in 35 seconds or better. The restoration actions are simple, can be completed by a control room operator, are contained in a procedure, and the HPCI function can be restored. The question is if credit for operator restoration can be taken in this case based on the system starting on an automatic signal, restoration actions are part of a normal response to the system start and contained in a procedure, and the operators are trained on this action? Can HPCI be considered available in this case? In general, must the SSC response be identical to a fully automatic initiation and how does this compare to "or the function can be immediately restored."	The unavailable hours would count because the system response specifically relies on operator action which is not "virtually certain to be successful" (NEI99-02 page 26 line 38). The operator actions have the potential to overspeed the turbine. Discussion issue: However, the total unavailable time that is incurred by this monthly sample is less than 0.07% unavailability for the 12 quarters. The NRC considers this to be negligible and does not have to be counted for this example. ok	PSEG

Summary of Meeting on Cross Cutting Issues Held on April 5, 2000

The following individuals attended the meeting:

- Wayne Lanning
- Elmo Collins
- John Pellet
- Geoff Grant (via video conference)
- Dan Dorman
- Juan Peralta
- Mary Ann Ashley
- Jeff Jacobson
- Alan Madison
- Bill Dean

Consideration of cross cutting issues in development of revised oversight process

The meeting began with an overview of how the cross cutting issues of human performance, safety conscious work environment, and problem identification and resolution (PI & R) were considered as part of the development of the revised oversight process. Basically, it was explained that, for the most part, these cross cutting issues were thought to be the root causes of performance issues that will be identified by either the established performance indicators or the baseline inspection program. For the cross cutting issue of human performance it was assumed that if risk informed inspections and plant performance indicators together indicate that plant performance is meeting the cornerstone objectives, then those findings also provide an indication of the acceptability of the associated human activities. The revised oversight process also assumes that a lack of safety conscious work environment will be identified by an increase in problems and events that will ultimately be picked up by the baseline inspection program or by performance indicators. Also, the issue of safety conscious work environment is considered during performance of the annual PI & R inspection.

With regard to licensee PI & R effectiveness, the framework for the revised oversight process identified several areas that are not specifically addressed by either the performance indicators or the routine baseline inspection attachments. As such, a specific inspection procedure (IP 71152) was written to assess licensee performance in the PI & R area.

Formulation of key issues associated with the current approach of addressing cross cutting issues

Individual work group members then brought forth their concerns regarding how the current oversight process treats cross cutting issues. These concerns were developed into key issues that require additional evaluation, as necessary to either validate the concern and determine corrective actions, or prove the concern invalid. Following is a summary of the key issues that were identified:

- Do the performance indicators and baseline inspection programs provide sufficient information regarding performance in the cross cutting areas of human performance, safety conscious work environment, and PI & R? For the purpose of this issue, " sufficient information" can be thought of as information of sufficient depth and scope and within a sufficient time frame to allow for appropriate levels of agency interaction.

Attachment 5

- Are there other cross cutting issues that warrant additional consideration in the revised oversight process?

- Does the revised oversight process (e.g. inspection program, SDPs, action matrix) provide for proper treatment of cross cutting issues when they are identified? Should the approach be the same for all cross cutting issues or should the approach vary?

- What would be the definition of a "substantial" cross cutting issue that would require additional agency actions beyond what the current process would provide?

- Currently, what is the guidance for capturing cross cutting issues in inspection reports?

Development of initial approach to address key issues

The work group discussed the above key issues and formulated actions that could be taken to achieve resolution. It was recognized by the group that resolution of these issues would likely be a long term effort (6 - 12 months) and will be aided by the additional experience that will be acquired with initial implementation of the revised oversight process. Following are the specific actions identified by the group to aid in resolution of the key issues:

- A review will be conducted of future inspection reports and LERs by the human factors section in NRR using the H.F.I.S to assess what human performance issues are being captured by the oversight process. Plants with above average human performance issues will then be analyzed further to see whether the oversight process provided sufficient information, in a sufficient time frame, regarding human performance issues.

- A review will be conducted of future events, to see whether the events were caused by cross cutting issues and whether the oversight process provided sufficient warning and treatment of cross cutting performance deficiencies. The group discussed various thresholds that could be used for initiating such a review including those associated with Special Inspections and Augmented Inspection Teams. The group also identified the need to decide who will perform the review, and whether existing event response inspection procedures need to be modified.

- A review will be conducted of all annual PI & R inspections to ensure that cross cutting issues are being appropriately captured. Also, Inspection Procedure 71152 will be reviewed to see if additional guidance is necessary to achieve consistent treatment of cross cutting issues in inspection reports.

- To address concerns regarding documenting cross cutting issues in inspection reports, the Inspection Program Branch discussed the planned revision to Inspection Manual Chapter 0610 and the branch's plans to review and comment on the first round of all inspection reports.

Plans for external stakeholder involvement

The work group discussed how external stakeholders would be included in resolution and formulation of the key issues. The group decided one additional meeting might be warranted before soliciting external stakeholder input.

June 5, 2000

MEMORANDUM TO: Michael R. Johnson, Section Chief
Inspection Program Branch
Division of Inspection Program Management

FROM: August K. Spector /RA/
Inspection Program Branch
Division of Inspection Program Management

SUBJECT: REACTOR OVERSIGHT PROCESS TO DISCUSS INITIAL REACTOR OVERSIGHT PROCESS IMPLEMENTATION PUBLIC MEETING MAY 2, 2000

The NRC conducted a public meeting on May 2, 2000, to discuss initial implementation at the Reactor Oversight Process. The meeting was held at the Nuclear Regulatory Commission, One White Flint North, Rockville, MD. A list of participants, the agenda, and handouts distributed are attached.

Attachments:
1. List of Participants
2. Agenda and Meeting Notes
3. NEI 99-02 Rev OCI
4. Frequently Asked Questions
5. Summary of Meeting on Cross Cutting Issues on April 5, 2000

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