Attachment 3

Issues/Concerns Documented in SECY-04-0053

1. Concern with Use of a Front Stop (Risk Limiter) for Risk-Significant Single Failures

The MSPI is designed to preclude a single risk significant failure from causing an NRC response beyond the baseline inspection program (the "Front Stop" concept). This concept was designed to address a concern for the "false positive" situation, where failures not indicative of current licensee performance with risk significance could inadvertently trip performance thresholds. However, occurrences of these types of failures are very infrequent and the vast majority of demand failures are associated with performance deficiencies.

2. Concern with Component Failure Rates and Use of a Constrained Non-informative Prior (CNIP) and Bayesian Updating over a 12 Quarter Time Window

MSPI estimates a change in core damage frequency (CDF) over 12 quarters of performance through use of generic industry failure means for the historical (prior) component failure distribution that is Bayesian updated with current performance data. The MSPI is characterized as a statistically significant, long-term performance trend indicator and it is influenced by two design features, use of a constrained, non-informative prior (CNIP) as a term in the component failure probability distribution, and Bayesian updating of the component prior with current, plant-specific failure data. Both of these features are desirable when attempting to identify a statistically valid, three year adverse trend in performance where site specific data is sparse. However, rapidly declining current performance over one or two quarters can be completely masked by the integration of average (or better than average) performance over the three years of performance monitoring. For components that have high reliability (and high risk worth), the CNIP approach may require a relative large number of failures before its mean value will significantly change. This causes a "pillow effect" (averaging of site and industry performance) that could mask some risk-significant failures. This "pillowing" effect creates a situation where there is an increase in the likelihood that the component failure would not trip a MSPI threshold, especially when combined with the Front Stop concept.

3. Concern with Masking Subsequent Failures in MSPI's White Band

Once the MSPI Green/White performance threshold is crossed, additional failures, even if risk-significant, could occur without the MSPI triggering additional regulatory response through the Action Matrix. Only when the Yellow band is crossed would additional regulatory response be generated.

4. Concern with the MSPI Not Including Risk from External Events, Internal Flooding, Shutdown Risk, Large Early Release Frequency (LERF), and the Limitations of MSPI Fussell-Vessly Risk Coefficients

The MSPI does not include the risk contribution due to external events, internal flooding, shutdown, large early release frequency (LERF), and risk contribution from other component failures. For example, in the case of one pilot plant, two-thirds of the overall plant risk is due to external events; at a non-pilot plant this fraction was over 80%. The SDP considers Large Early Release Frequency (LERF); MSPI as currently proposed, does not. Under the current ROP guidelines, LERF and external events are required to be evaluated. The current MSPI as piloted, would in a defacto sense, prevent this assessment from occurring. Additionally, the Fussell-Vessly (F-V) coefficient used in MSPI is calculated by holding all other equipment failures constant, except for one component. The F-V ratio term used in the MSPI equation does not account for other component failures. The F-V ratio term also does not account for operator recovery of failed equipment, when appropriate.

5. The Projected Costs for the NRC Associated with Implementing MSPI if SDP is Eliminated Without Suitable PRA Standards and Models are High and Not Included in Current Budget Projections

a. <u>2-Year Initial Implementation (all four regions)</u>

(3) 3day(8hr/day) wkshops + 3 day training course = (72 + 72 hrs)/site * 2 inspectors * 70 sites = 20,160 hrs
(3) 3day(8hr/day) workshops + 3 day training course = (72 + 72 hrs) (40 reg. and hqs. staff) = 5760 hrs
Regional TI DIE expenditure = 200 hrs/site for 70 sites = 14000 hrs
Prep and Doc = .75 (14000 hrs/site) 70 sites = 10,500 hrs
FAQ resolution = 40 hours/month hqs + 80 hrs/mo regions = 120 hrs/mo * 24 months = 2880 hrs
Contractor/TI support = 1 FTE/yr for 2 years
Total: = 53300 hrs/1140 hrs/FTE = 46.7 FTE

b. <u>Long term MSPI Verification and Oversight (all four regions)</u>

PI Verification baseline inspections = 50 hrs (70 sites) = 3500 hrs/yr (3.1 FTE)
Prep and Doc = .75 (3500 hrs/yr) = 2625 hrs/1150 hrs = (2.3 FTE)
FAQ resolution (hqs + regions) = 10 hrs/mo (hqs) + 20 hrs/mo (regions) = 360 hr/yr (.3 FTE)
SPAR periodic upgrades = + 300 K/yr
Total: = 5.7 FTE & 300K (note: Total with using SSU PIs = 3.2 FTE)

c. <u>Concern with SPARs for the Non-MSPI Pilot Plants that Need to be Upgraded to the Level of Fidelity and Quality Similar to the MSPI Pilot Plants</u>

During the MSPI pilot, the staff and pilot licensees exchanged information and performed detailed comparison studies between the existing SPAR rev 3i models and with the PRAs. The pilot effort identified discrepancies in both the SPAR models and with the assumptions in the PRA models. The pilot effort was successful in part due to industry providing a level of commitment that enable the staff to fully understand the differences between SPAR and PRA. Although not part of the current tasking and effort to upgrade SPARs, the level of industry commitment to provide information demonstrated during the MSPI pilot needs to be extended for the rest of industry.

d. <u>Lack of a Suitable PRA Standard for MSPI</u>

Both the Unreliability Index (URI) and Unavailability Index (UAI) portion of the MSPI equation use two multipliers that relate directly to the particular PRA model that is used by the licensee. However, no PRA quality standard has been established for the various licensee PRA models. The limited reviews between the NRC's SPAR models and the pilot program licensee's PRA models have already revealed modeling differences that would likely result in different regulatory responses due to the model used. In lieu of a suitable PRA standard, a standardized set of PRA guidelines as agreed to by the staff and industry should be in place prior to MSPI implementation.

e. Concern with the Staff Receiving Large Numbers of Frequently Asked Questions (FAQs) During MSPI Initial Implementation and Long Term Oversight

The staff is concerned that because MSPI is a complex PRA-based indicator, numerous FAQs would be generated that would create inefficiencies and resource issues. Part of minimizing this impact is to revise the FAQ process that allows for a finite period to discuss and resolve the issue, with the staff having the final decision authority to decide the outcome in a reasonable period of time. This process needs to be in place prior to implementing a revised, acceptable version of MSPI.

6. Concern with the Elimination of SDP for Areas Covered by MSPI

Prompt evaluation and assessment of performance deficiencies is a major premise of the Reactor Oversight Process (ROP) and is currently only performed by the Significance Determination Process (SDP). Implementing the Mitigating Systems Performance Index (MSPI) with the elimination of the SDP, as currently proposed, would prevent this goal from being met, and would constitute a major fundamental change in the ROP. MSPI is blind to the presence of performance deficiencies and not focused on identifying individual event significance. Additionally, risk assessment under MSPI (the detection of statistically significant adverse trends in performance), and risk assessment under the SDP (the evaluation and assessment of individual events), would cause a dichotomy in how the ROP treats MSPI-monitored components and those components that would still be assessed under the SDP process.

7. Concern with the ROP's Enforcement Policy

Enforcement will not be based on the significance of the specific issues but on an accumulated significance over a 3 year period. Identical issues on different units could result in different NRC responses, and less significant issues could result in higher NRC responses than a more significant issue (depends on order of occurrence). Even similar issues on the same unit could result in different enforcement, especially where fault exposure hours occur.

8. Concern with Fault Exposure Unavailability

The MSPI does not include system unavailabilities due to fault exposure hours; consequently, a potentially significant portion of the risk contribution due to actual unavailability is unaccounted for in the indicator. Unlike the MSPI, the SDP evaluates the risk increase using the true exposure time and, if it is not known, the program reasonably defaults to one-half the time since the function was confirmed to be operational. This exposure time is not part of MSPI even though the system function was lost (unavailable) for that time frame. Instead, the MSPI would take a demand and demand failure as a surrogate for the lost fault exposure unavailability. While this is a reasonable action to take for purposes of estimating unreliability, the risk contribution from the system being unavailable due to the fault exposure hours for long periods of time could be significantly underestimated by MSPI.

9. Concerns with Maintaining Public Confidence

The MSPI concept will be difficult for the public to understand. The data will not be available for public review. Currently, the licensee reports for the SSU PI unavailability hours with each monitored system. Using this information, the public can understand how the color for a performance indicator was determined. Under the MSPI, the impact on the unavailability index due to an out of service unavailability is not intuitively obvious. The diminished ability of the public to understand MSPI raises a question regarding the level of NRC independent verification that would be necessary to enhance public confidence and ensure that the MSPI would be correctly reported.

Attachment 4

TempNo.	PI	Question/Response	Status	Plant/ Co.
27.3	IE02	Question: Should a reactor scram due to high reactor water level, where the feedwater pumps tripped due to the high reactor water level, count as a scram with a loss of normal heat removal Background Information: On April 6, 2001 LaSalle Unit 2 (BWR), during maintenance on a motor driven feedwater pump regulating valve, experienced a reactor automatic reactor scram on high reactor water level. During the recovery, both turbine driven reactor feedwater pumps (TDRFPs) tripped due to high reactor water level. The motor driven reactor feedwater pump was not available due to the maintenance being performed. The reactor operators choose to restore reactor water level through the use of the Reactor Core Isolation Cooling (RCIC) System, due to the fine flow control capability of this system, rather than restore the TDRFPs. Feedwater could have been restored by resetting a TDRFP as soon as the control board high reactor water level alarm cleared. Procedure LGA-001 "RPV Control" (Reactor Pressure Vessel control) requires the unit operator to "Control RPV water level between 11 in. and 59.5 in. using any of the systems listed below: Condensate/feedwater, RCIC, HPCS, LPCS, LPCI, RHR." The following control room response actions, from standard operating procedure LOP-FW-04, "Startup of the TDRFP" are required to reset a TDRFP. No actions are required outside of the control room (and no diagnostic steps are required). Verify the following: TDRFP M/A XFER (Manual/Automatic Controller) station is reset to Minimum No TDRFP trip signals are present Depress TDRFP Turbine RESET pushbutton and observe the following Turbine RESET light Illuminates TDRFP High Pressure and Low Pressure Stop Valves OPEN PUSH M/A increase pushbutton on the Manual/Automatic Controller station Should this be considered a scram with the loss of normal heat removal? Proposed Answer: The ROP working group is currently working to prepare a response.	1/25 Introduced 2/28 NRC to discuss with resident 4/25 Discussed 5/22 On hold 6/12 Discussed. Related FAQ 30.8 9/26 Discussed 10/31 Discussed	LaSalle
28.3	IE02	Question: This event was initiated because a feedwater summer card failed low. The failure caused the feedwater circuitry to sense a lower level than actual. This invalid low level signal caused the Reactor Recirculation pumps to shift to slow speed while also causing the feedwater system to feed the Reactor Pressure Vessel (RPV) until a high level scram (Reactor Vessel Water Level – High, Level 8) was initiated. Within the first three minutes of the transient, the plant had gone from Level 8, which initiated the scram, to Level 2 (Reactor Vessel Water Level – Low Low, Level 2), initiating High Pressure Core Spray (HPCS) and Reactor Core Isolation Cooling (RCIC) injection, and again back to Level 8. The operators had observed the downshift of the Recirculation pumps nearly coincident with the scram, and it was not immediately apparent what had caused the trip due to the rapid sequence of events. As designed, when the reactor water level reached Level 8, the operating turbine driven feed pumps tripped. The pump control logic prohibits restart of the feed pumps (both the turbine driven pumps and motor driven feed pump	3/21 Discussed 4/25 Discussed 5/22 Modified to reflect discussion of 4/25, On Hold 6/12 Discussed. Related FAQ 30.8	Perry

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		(MFP)) until the Level 8 signal is reset. (On a trip of one or both turbine feed pumps, the MFP would automatically start, except when the trip is due to Level 8.) All three feedwater pumps (both turbine driven pumps and the MFP) were physically available to be started from the control room, once the Level 8 trip was reset. Procedures are in place for the operators to start the MFP or the turbine driven feedwater pumps in this situation. Because the cause of the scram was not immediately apparent to the operators, there was initially some misunderstanding regarding the status of the MFP. (Because the card failure resulted in a sensed low level, the combination of the recirculation pump downshift, the reactor scram, and the initiation of HPCS and RCIC at Level 2 provided several indications to suspect low water level caused the scram.) As a result of the initial indications of a plant problem (the downshift of the recirculation pumps), some operators believed the MFP should have started on the trip of the turbine driven pumps. This was documented in several personnel statements and a narrative log entry. Contributing to this initial misunderstanding was a MFP control power available light bulb that did not illuminate until it was touched. In fact, the MFP had functioned as it was supposed to, and aside from the indication on the control panel, there were no impediments to restarting any of the feedwater pumps from the control room. No attempt was made to manually start the MFP prior to resetting the Level 8 feedwater trip signal. Regardless of the issue with the MFP, however, both turbine driven feed pumps were available once the high reactor water level cleared, and could have been started from the control room without diagnosis or repair. Procedures are in place to accomplish this restart, and operators are trained in the evolution. Since RCIC was already in operation, operators elected to use it as the source of inventory, as provided for in the plant emergency instructions, until plant conditions stabilized. Should this event be counted as a Scram with a Loss of Normal Heat Removal? Response: The ROP working group is currently working to prepare a response.		
30.8	IE02	Question: Many plant designs trip the main feedwater pumps on high reactor water level (BWRs), and high steam generator water level or certain other automatic trips (PWRs). Under what conditions would a trip of the main feedwater pumps be considered/not considered a scram with loss of normal heat removal? Response: The ROP working group is currently working to prepare a response.	5/22 Introduced 6/12 Discussed 9/26 Discussed. 10/31 Discussed	Generic
32.3a	IE02	Question: An unplanned scram occurred October 7, 2001, during startup following an extended forced outage. The unit was in Mode 1 at approximately 8% reactor power with a main feed pump and low-flow feedwater preheating in service. The operators were preparing to roll the main turbine when a reactor tripped occurred. The cause of the trip was a loss of voltage to the control rod drive mechanisms and was not related to the heat removal path. Main feedwater isolated on the trip, as designed, with the steam generators being supplied by the auxiliary feedwater (AFW) pumps. At 5 minutes after the trip, the reactor coolant system (RCS) temperature was 540 degrees and trending down. The operators verified that the steam dumps, steam generator power operated relief valves, start-up steam supplies and blowdown were isolated. Additionally, AFW flow was isolated to all Steam Generators as allowed by the trip response procedure. At 9 minutes after the trip, with RCS temperature still trending down, the main steam isolation valves (MSIV) were closed in accordance with the reactor trip response procedure curtailing the cooldown. The RCS cooldown was attributed to steam that was still being supplied to low-flow feedwater preheating and #4 steam generator AFW flow control valve not automatically moving to its flow retention position as expected with high AFW flow. The low-flow feedwater preheating is a known steam load during low power operations and the AFW flow control issue was identified by the control room balance of plant operator. The trip response procedure directs the operators to check for and take actions to control AFW flow and eliminate the feedwater heater steam	1/23 Revised. Split into two FAQs 3/20 Discussed 5/1 Discussed 5/22 Tentative Approval 6/18 Discussion deferred to July 7/24 Discussed	DC Cook

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		supply. When this trip occurred the unit was just starting up following a 40 day forced outage. The reactor was at approximately 8% power and there was very little decay heat present following the trip. With very little decay heat available, the primary contribution to RCS heating is from Reactor Coolant Pumps (RCPs). Evaluation of these heat loads, when compared to the cooling provided by AFW, shows that there is approximately 3.5 times as much cooling flow provided than is required to remove decay heat under these conditions plus pump heat. This resulted in rapid cooling of the RCS and ultimately required closure of the MSIVs. Other conditions such as low flow feedwater preheating and the additional AFW flow due to the AFW flow control valve failing to move to its flow retention setting contributed to this cooldown, but were not the primary cause. Even without these contributors to the cooldown, closure of MSIVs would have been required due to the low decay heat present following the trip. It should also be noted that the conditions that are identified as contributing to the cooldown are not conditions which prevent the secondary plant from being available for use as a cooldown path. The AFW flow control valve not going to the flow retention setting increases the AFW flow to the S/G, and in turn causes an increase in cooldown. This condition is corrected by the trip response procedure since the procedure directs the operator to control AFW flow as a method to stabilize the RCS temperature. With low-flow feedwater preheating in service, main steam is aligned to feedwater heaters 5 and 6 and is remotely regulated from the control room. Low-flow feedwater preheating is used until turbine bleed steam is sufficient to provide the steam supply then the system is isolated. There are no automatic controls or responses associated with the regulating valves, so when a trip occurs, operators must close the regulating valves to secure the steam source. Until the steam regulating valves are closed, this is a steam load contributing to a cooldown. The low-flow preheating steam supplies are identified in the trip response procedure since they are a CNP specific design issue. The actions taken to control RCS cooldown were in accordance with the plant procedure in response to the trip. The primary reason that the MSIVs were required to be closed was due to the low level of decay heat present following a 40 day forced outage. The closure of the MSIVs was to control the cooldown as directed by plant procedure and not to mitigate an off-normal condition or for the safety of personnel or equipment. With the low decay heat present following the 40 day forced outage, there would not have been a need to reopen the MSIVs prior to recommencing the startup. Should the reactor trip described above be counted in the Unplanned Scrams with Loss of Normal Heat Removal Performance Indicator?		
		Response: Yes. The licensee's reactor trip response procedure has an "action/expected response" that reactor coolant system temperature following a trip would be stable at or trending to the no-load Tavg value. If that expected response is not obtained, operators are directed to stop dumping steam and verify that steam generator blowdown is isolated. If cooldown continues, operators are directed to control total feedwater flow. If cooldown continues, operators are directed to close all steam generator stop valves (MSIVs) and other steam valves. During the unit trip described, the #4 steam generator auxiliary feedwater flow control valve did not reposition to the flow retention setting as expected (an off normal condition). In addition, although control room operators manually closed the low-flow feedwater preheat control valves that were in service, leakage past these valves (a pre-existing degraded condition identified in the Operator Workaround database) also contributed to the cooldown. Operator logs attributed the reactor system cooldown to the #4 AFW flow control valve failure as well as to steam being supplied to low-flow feedwater preheating. As stated above, the trip response procedure directs operators to control feedwater flow in order to control the cooldown. Operator inability to control the cooldown through control of feedwater flow as directed is considered an off normal condition. Since the cooldown continued due to an off normal condition, operators closed the MSIVs, and therefore this trip is considered a scram with loss of normal heat removal.		
34.6	IE02	Question:	3/20 Introduced	STP

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		Should the following event be counted as a scram with loss of normal heat removal? STP Unit Two was manually tripped on Dec. 15, 2002 as required by the off normal procedure for high vibration of the main turbine. Approximately 17 minutes after the Unit was manually tripped main condenser vacuum was broken at the discretion of the Shift Supervisor to assist in slowing the turbine. Plant conditions were stabilized using Auxiliary Feedwater and Steam Generator Power Operated Relief Valves. Main Feedwater remained available via the electric motor driven Startup Feedwater pump. Main steam headers remained available to provide cooling via the steam dump valves. At any time vacuum could have been reestablished without diagnoses or repair using established operating procedures until after completion of the scram response procedures. Scrams with a Loss of Normal Heat Removal performance indicator is defined as *"The number of unplanned scrams while critical, both manual and automatic, during the previous 12 quarters that were either caused by or involved a loss of the normal heat removal path prior to establishing reactor conditions that allow use of the plant's normal long term heat removal systems."* This indicator states that a loss of normal heat removal has occurred whenever any of the following conditions occur: loss of main feedwater, loss of main condenser vacuum, closure of the main steam isolation valves or loss of turbine bypass capability. The determining factor for this indicator is whether or not the normal heat removal path is available, not whether the operators choose to use that path or some other path. The STP plant is designed to isolate main feedwater after a trip by closing the main feedwater control valves. The auxiliary feedwater pumps are then designed to start on low steam generator levels. This is expected following normal operation above low power levels and in turn provides the normal heat removal. This design functioned as expected on December 15, 2002 when the reactor was manually tripped due to high turbine vibration. Normal plant operating procedures 0POP03-ZG-0006 (Plant Shutdown from 100% to Hot Standby) and 0POP03-ZG-0001 (Plant Heatup) state if Auxiliary Feedwater is being used to feed the steam generators than the preferred method of steaming is through the steam generator power operated relief valves. This can be found in steps 7.4 and 7.5 of 0POP03-ZG-0001 and steps 6.6.5 and 6.6.10 of 0POP03-ZG-0006. The note prior to 6.6.10 states *"the preferred method for controlling SG steaming rates while feeding with AFW is with the SG PORVs"*. The normal heat removal path as defined in NEI 99-02 Revision 2 was in service and functioning properly for seventeen minutes after the manual reactor trip and would have continued to function had not the shift supervisor voluntarily broke condenser vacuum and closed the MSIV's. Interviews with the shift supervisor showed that the decision to break vacuum was two part. 1) Based on experience and reports from the field it was known that vacuum would need to be broken to support the maintenance state required for the main turbine and at a minimum to support timely inspection. 2)This would assist in slowing the turbine. The decision to break vacuum was not based solely on mitigating an off-normal condition or for the safety of personnel or equipment. Because Auxiliary Feedwater system had actuated and was in service as expected, the decision was made to use Auxiliary Feedwater and steam through the SG PORVs. As stated earlier, this is the preferred method of heat removal if the decision to use Auxiliary Feedwater is employed as supported by the normal operating procedures while the plant is in Mode 3. Main feedwater remained available via the electric motor driven Startup Feedwater pump and the main steam headers remained available to provide cooling via the steam dump valves if required. Discussion with the shift supervisor showed he was confident that at any time vacuum could have been readily recovered from the control room without the need for diagnoses or repair using established operating procedures if the need arose. An outside action would be required in drawing vacuum in that a Condenser Air Removal pump would require starting locally in the TGB. This is a simplistic, proceduralized and commonly performed evolution. Personnel are fully confident this would have been performed without incident if required. Closing the MSIVs and breaking vacuum as quickly as possible is not uncommon at STP. For a normal planned shutdown MSIVs are closed and vacuum broken within four to six hours typically to support required maintenance in the secondary. If maintenance in the secondary is known to be critical path than vacuum has been broken as early	3/20 Discussed 6/18 Discussed; Question to be revised to reflect discussion 7/24 Discussed	

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		as three hours and fifteen minutes following opening of the main generator breaker. The only reason that vacuum is not broken sooner is because in most cases it is needed to support chemistry testing. By limiting the flow path as described in NEI 99-02 for normal heat removal there is undue burden being placed on the utility. Only recognizing this one specific flow path reduces operational flexibility and penalizes utilities for imparting conservative decision making. Conditions are established immediately following a reactor trip (100% to Mode 3) that can be sustained indefinitely using Auxiliary Feedwater and steaming through the steam generator PORVs. This fact is again supported in the stations Plant Shutdown from 100% to Hot standby and Plant Heatup normal operating procedures. The cause of a trip, the intended forced outage work scope, or outage duration varies and inevitably will factor into which method of normal long term heat removal is best for the station to employ shortly following a trip.		
		Response: The ROP working group is currently working to prepare a response. Licensee Proposed Response: NO. Since vacuum was secured at the discretion of the Shift Supervisor and could have been restored using existing normally performed operating procedures, the function meets the intention of being available but not used.		
36.1	IE02	Question: With the unit in RUN mode at 100% power, the control room received indication that a Reactor Pressure Vessel relief valve was open. After taking the steps directed by procedure to attempt to reseat the valve without success, operators scrammed the reactor in response to increasing suppression pool temperature. Following the scram, and in response to procedural direction to limit the reactor cooldown rate to less than 100 degrees per hour, the operators closed the Main Steam Isolation Valves (MSIVs). The operators are trained that closure of the MSIV's to limit cool down rate is expected in order to minimize steam loss through normal downstream balance-of-plant loads (steam jet air ejectors, offgas preheaters, gland seal steam). At the time that the MSIVs were closed, the reactor was at approximately 500 psig. One half hour later, condenser vacuum was too low to open the turbine bypass valves and reactor pressure was approximately 325 psig. Approximately eight hours after the RPV relief valve opened, the RPV relief valve closed with reactor pressure at approximately 50 psig. This information is provided to illustrate the time frame during which the reactor was pressurized and condenser vacuum was low. Although the MSIVs were not reopened during this event, they could have been opened at any time. Procedural guidance is provided for reopening the MSIVs. Had the MSIVs been reopened within approximately 30 minutes of their closure, condenser vacuum was sufficient to allow opening of the turbine bypass valves. If it had been desired to reopen the MSIVs later than that, the condenser would have been brought back on line by following the normal startup procedure for the condenser. As part of the normal startup procedure for the condenser, the control room operator draws vacuum in the condenser by dispatching an operator to the mechanical vacuum pump. The operator starts the mechanical vacuum pump by opening a couple of manual valves and operating a local switch. All other actions, including opening the MSIVs and the turbine bypass valves, are taken by the control room operator in the control room. It normally takes between 45 minutes and one hour to establish vacuum using the mechanical vacuum pump. The reactor feed pumps and feedwater system remained in operation or available for operation throughout the event. The condenser remained intact and available and the MSIVs were available to be opened from the control room throughout the event. The normal heat removal path was always and readily available (i.e., use of the normal heat removal path required only a decision to use it and the following of normal station procedures) during this event. Does this scram constitute a scram with a loss of normal heat removal?	9/25 Introduced and discussed	Quad Cities

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		Response: No. The normal heat removal path was not lost even though the MSIVs were manually closed to control cooldown rate. There was no leak downstream of the MSIVs, and reopening the MSIVs would not have introduced further complications to the event. The normal heat removal path was purposefully and temporarily isolated to address the cooldown rate, only. Reopening the normal heat removal path was always available at the discretion of the control room operator and would not have involved any diagnosis or repair. Further supporting information: The clarifying notes for this indicator state: "*Loss of normal heat removal path* means the loss of the normal heat removal path as defined above. The determining factor for this indicator is whether or not the normal heat removal path is *available*, not whether the operators choose to use that path or some other path." In this case, the operator did not choose to use the path through the MSIVs, even though the normal heat removal path was available. The clarifying notes for this indicator also state: "*Operator actions or design features to control the reactor cooldown rate or water level*, such as closing the main feedwater valves or closing all MSIVs, are not reported in this indicator as long as the normal heat removal path can be readily recovered from the control room without the need for diagnosis or repair." In this case, the closing of the MSIVs was performed solely to control reactor cooldown rate. It was not performed to isolate a steam leak. There was no diagnosis or repair involved in this event. The MSIVs could have been reopened following normal plant procedures		
36.2	IE02	Question: Should an "Unplanned Scram with a Loss of Normal Heat Removal" be reported for the Peach Bottom Unit 2 (July 22, 2003) reactor scram followed by a high area temperature Group I isolation? Description of Event: At approximately 1345 on 07/22/03, a Main Generator 386B and 386F relay trip resulted in a load reject signal to the main turbine and the main turbine control valves went closed. The Unit 2 reactor received an automatic Reactor Protection System (RPS) scram signal as a result of the main turbine control valves closing. Following the scram signal, all control rods fully inserted and, as expected, Primary Containment Isolation System (PCIS) Group II and III isolations occurred due to low Reactor Pressure Vessel (RPV) level. The Group III isolation includes automatic shutdown of Reactor Building Ventilation. RPV level control was re-established with the Reactor Feed System and the scram signal was reset at approximately 1355 hours. At approximately 1356 hours, the crew received a High Area Temperature alarm for the Main Steam Line area. The elevated temperature was a result of the previously described trip of the Reactor Building ventilation system. At approximately 1358, a PCIS Group I isolation signal occurred due to Steam Tunnel High Temperature resulting in the automatic closure of all Main Steam Isolation Valves (MSIV).Following the MSIV closure, the crew transitioned RPV pressure and level control to the High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) systems. Following the reset of the PCIS Group II and III isolations at approximately 1408, Reactor Building ventilation was restored. At approximately 1525, the PCIS Group I isolation was reset and the MSIVs were opened. Normal cooldown of the reactor was commenced and both reactor recirculation pumps were restarted. Even though the Group I isolation could have been reset following the Group II/III reset at 1408, the crew decided to pursue other priorities before reopening the MSIVs including: stabilizing RPV level and pressure using HPCI and RCIC; maximizing torus cooling; evaluating RCIC controller oscillations; evaluating a failure of MO-2-02A-53A "A" Recirculation Pump Discharge Valve; and, minimizing CRD flow to facilitate restarting the Reactor Recirculation pumps. **Problem Assessment:** It is recognized that loss of Reactor Building ventilation results in rising temperatures in the Outboard MSIV Room. The rate of this temperature rise and the maximum temperature attained are exacerbated by summertime temperature conditions. When the high temperature isolation occurred, the crew immediately recognized and understood the	9/25 Introduced and discussed	Peach Bottom

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		cause to be the loss of Reactor Building ventilation. The crew then prioritized their activities and utilized existing General Plant (GP) and System Operating (SO) procedures to re-open the MSIVs. Reopening of the MSIVs was: • easily facilitated by restarting Reactor Building ventilation, • completed from the control room using normal operating procedures • without the need of diagnosis or repair Therefore, the MSIV closure does not meet the definition of "Loss of normal heat removal path" provided in NEI 99-02, Rev. 2, page 15, line 37, and it is appropriate not to include this event in the associated performance indicator – Unplanned Scrams with Loss of Normal Heat Removal. Discussion of specific aspects of the event: Was the recognition of the condition from the Control Room? ▪ Yes. Rising temperature in the Outboard MSIV Room is indicated by annunciator in the main control room. Local radiation levels are also available in the control room. During the July 22, 2003 scram, control room operators also recognized that the increase in temperature was not due to a steam leak in the Outboard MSIV Room because the local radiation monitor did not indicate an increase in radiation levels. Initiation of the Group I isolation on a Steam Tunnel High Temperature is indicated by two annunciators in the control room. Does it require diagnosis or was it an alarm? ▪ The event is annunciated in the control room as described previously. Is it a design issue? ▪ Yes. The current Unit 2 design has the Group I isolation temperature elements closer to the Outboard MSIV Room ventilation exhaust as compared to Unit 3. As a result, the baseline temperatures, which input into the Group I isolation signal, are higher on Unit 2 than Unit 3. Are actions virtually certain to be successful? ▪ The actions to reset a Group I isolation are straight forward and the procedural guidance is provided to operate the associated equipment. No diagnosis or troubleshooting is required. Are operator actions proceduralized? ▪ The actions to reset the Group I isolation are delineated in General Plant procedure GP-8.A "PCIS Isolation-Group I." The actions to reopen the MSIVs are contained in System Operating procedures SO 1A.7.A-2 "Main Steam System Recovery Following a Group I Isolation" and Check Off List SO 1A.7.A-2 "Main Steam Lineup After a Group I Isolation." These procedures are performed from the control room. How does Training address operator actions? ▪ The actions necessary for responding to a Group I isolation and subsequent recovery of the Main Steam system are covered in licensed operator training. Are stressful or chaotic conditions during or following an accident expected to be present? • As was demonstrated in the event of July 22, 2003, sufficient time existed to stabilize RPV level and pressure control and methodically progress through the associated procedures to reopen the MSIVs without stressful or chaotic conditions		

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		Response: The Peach Bottom Unit 2 July 22, 2003 reactor scram followed by a high area temperature Group I isolation should not be included in the Performance Indicator - "Unplanned Scram with a Loss of Normal Heat Removal." This specific MSIV closure does not meet the definition of "Loss of normal heat removal path" provided in NEI 99-02, Rev. 2, page 15, line 37, in that the main steam system was "easily recovered from the control room without the need for diagnosis or repair. Therefore, it would not be appropriate to include this event in the associated performance indicator – Unplanned Scrams with Loss of Normal Heat Removal.		
36.8	IE02	Question: On August 14, 2003 Ginna Station scrammed due to the wide spread grid disturbance in the Northeast United States. Subsequent to the scram, Main Feedwater Isolation occurred as designed on low Tavg coincident with a reactor trip. However, due to voltage swings from the grid disturbance, instrument variations caused the Advanced Digital Feedwater Control System (ADFCS) to transfer to manual control. This transfer overrode the isolation signal causing the Main Feedwater Regulation Valves (MFRVs) to go to, and remain at, the normal or nominal automatic demand position at the time of the transfer, resulting in an unnecessary feedwater addition. The feedwater addition was terminated when the MFRVs closed on the high-high steam generator level (85%) signal. Operators conservatively closed the MSIVs in accordance with the procedure to mitigate a high water level condition in the Steam Generators. Decay heat was subsequently removed using the Atmospheric Relief Valves (ARVs). Should the scram be counted under the PI "Unplanned Scrams with Loss of Normal Heat Removal?" Response: No. Under clarifying notes, page 16, lines 18 - 22, NEI 99-02 states: "Actions or design features to control the reactor cool down rate or water level, such as closing the main feedwater valves or closing all MSIVs, are not reported in this indicator as long as the normal heat removal path can be readily recovered from the control room without the need for diagnosis or repair. However, operator actions to mitigate an off-normal condition or for the safety of personnel or equipment (e.g., closing MSIVs to isolate a steam leak) are reported." In this case, a feedwater isolation signal had automatically closed the main feed regulating valves, effectively mitigating the high level condition. Manually closing the MSIVs was a conservative procedure driven action, which in this case was not by itself necessary to protect personnel or equipment. The main feed regulating valves were capable of being easily opened from the control room, and the MSIVs were capable of being opened from the control room (after local action to bypass and equalize pressure, see FAQ 303). In addition, the cause of the high steam generator level was due to voltage fluctuations on the offsite power grid which resulted in the operators closing the MSIVs. Clarifying notes for this performance indicator exempt scrams resulting in loss of all main feedwater flow , condenser vacuum, or turbine bypass capability caused by loss of offsite power. In this case, offsite power was not lost. However, the disturbances in grid voltage affected the ADFCS system which started a chain of events which ultimately resulted in the closure of the MSIVs.	1/22 Introduced 3/25 Discussed	Ginna
36.9	IE02	Question: During startup activities following a refueling outage in which new monoblock turbine rotors were installed in the LP turbines, reactor power was approximately 10% of rated thermal power, and the main turbine was being started up. Feedwater was being supplied to the steam generators by the turbine driven main feedwater pumps, and the main condensers were in service. During main turbine startup, the turbine began to experience high bearing vibrations before reaching its normal operating speed of 1800 rpm, and was manually tripped. The bearing vibrations began to increase as the turbine slowed down following the trip. To protect the main turbine, the alarm response procedure for high-high turbine vibration required the operators to manually SCRAM the reactor, isolate steam to the main condensers by closing the main steam isolation valves and to open the condenser vacuum breaker thereby isolating the normal heat removal path to the main condensers. This caused the turbine driven main	1/22 Introduced 3/25 Discussed. Question to be rewritten and response provided 4/22 Question and response provided	Millstone 2

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		feedwater pumps to trip. Following the reactor SCRAM, the operators manually started the auxiliary feedwater pumps to supply feedwater to the steam generators. Based on industry operating experience, operators expected main turbine vibrations during this initial startup. Nuclear Engineering provided Operations with recommendations on how to deal with the expected turbine vibration issues that included actions up to and including breaking condenser vacuum. Operations prepared the crews for this turbine startup with several primary actions. First, training on the new rotors, including industry operating experience and technical actions being taken to minimize the possibility of turbine rubs was conducted in the pre-outage Licensed Operator Requalification Training. Second, the Alarm Response Procedures (A-34 and B-34) for turbine vibrations were modified to include procedures to rapidly slow the main turbine to protect it from damage. Under the worst turbine vibration conditions, the procedure required operators to trip the reactor, close MSIVs and break main condenser vacuum. Third, operating crews were provided training in the form of a PowerPoint presentation for required reading which included a description of the turbine modifications, a discussion of the revised Alarm Response Procedures and industry operating experience. Does a SCRAM in which the normal heat removal path is manually isolated in accordance with normal plant procedures for protection of non-safety plant equipment count against this indicator?		
		Response: No, this scram does not count against the performance indicator for scrams with loss of normal heat removal. The conditions that resulted in the closure of the MSIVs after the reactor trip where expected for the main turbine startup following rotor replacement. Operator actions for this situation had been incorporated into normal plant procedures.		
37.3	OR1	Question: It was determined that a physical barrier being used to control access to a high radiation area (greater than 1000 mrem per hour) could easily be circumvented. However, to circumvent the controls that were in place would require an intentional act. An example of this might include one of the following; 1. Fencing used as a barrier at the boundary of the high radiation area was not firmly secured (i.e., loosely secured, or just taped to a wall) such that an individual could, by hand, create an opening large enough to pass through. 2. The barrier was constructed of a material that could easily be breached with a pocket knife (i.e., thin plastic sheeting or webbing). 3. An individual could pass their hand through the barrier and open the locked door to the area from the inside. 4. The barrier is a short fence (<6 foot high), or hand rail, such that an individual could step over, climb over, or crawl under, with little-to-moderate effort. 5. A locked gate is provided at the top of a ladder to control access to a high radiation area on a lower level of the plant. However, by stepping around (or over) the gate, an individual can still access to the rungs of the ladder. Since the controls in place, as described above, were adequate to prevent an inadvertent entry (i.e., accidental or unintentional entry by an individual not paying sufficient attention), and the definition of terms on page 98 in NEI 99-02 Rev. 2, refers to "measures that provide assurance that inadvertent entry into the technical specification high radiation areas by unauthorized personnel," is this a (or are these) reportable PI occurrence(s)? How about if this were a very high radiation area (>500 rads per hour)?	3/25 Introduced 4/22 Directed to HP counterparts for review	NRC
		Response: The first example on page 99 of NEI 99-02, Rev.2, clearly states that the failure to secure a high radiation area (>1000 mrem per hour) against unauthorized access is a reportable PI occurrence. Since the physical barriers provided for each of these areas can be easily circumvented (i.e., did not secure the area), they would each be a PI occurrence. The term "inadvertent entry" on page 98 of NEI 99-02, is used in the sense that the violation of the regulatory requirement (e.g., resulting from the unauthorized entry) was unintended, as opposed to whether the act		

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		itself was accidental or unintended. As used here, an unintentional violation could be a non-flagrant, intended, act resulting from a misunderstanding as to the existence the requirement, the meaning of the requirement, or that the action conformed to the requirement. If the unauthorized entry was an intended violation of the regulatory requirement, this would be a willful violation subject to normal NRC Enforcement Policy. A willful violation is outside the scope of this Performance Indicator..		
37.4	IE03	Question: During a scheduled refueling outage, the rotor was replaced on the 'C' low pressure turbine. During initial startup on October 27, 2003, with the plant stable at 17.7% reactor power, high vibrations were detected on the bearings associated with the replaced rotor. The turbine was tripped and shutdown, a troubleshooting team formed and a repair plan developed. In order to collect vibration data required to identify the optimum location for the placement of balancing weights, the repair plan called for the starting and phasing of the main turbine. With reactor power at 22.2%, the main generator breaker was closed at 18:32. After the collection of vibration data, the turbine was tripped at 20:37 and reactor power reduced to 1.1%. When the performance indicator data for the 4th quarter of 2003 was submitted, this reduction in power of 21.1% was not included in the Unplanned Power Changes per 7,000 Critical Hours Performance Indicator. The NEI 99-02 criteria for reporting power changes of greater than 20% is for discovered off-normal conditions that require a power change of greater than 20% to resolve. Frequently, high vibrations and/or rubbing occur during startup following rotor replacement. As an expected condition rather than an off-normal condition, the associated reduction in power should not count as an unplanned power change. Is the power change described above considered an unplanned power change for performance indicator reporting? Response: No. Because the power change occurred in a refueling outage during troubleshooting activities associated with turbine rotor replacement, it should not be counted as an unplanned power change against the Unplanned Power Changes per 7,000 Critical Hours performance indicator.	3/25 Introduced 4/22 Need additional information	Seabrook
37.5	OR1	<u>Question:</u> <u>A worker entered a Technical Specification High Radiation Area (> 1R/hr) with all requirements of the job (training, briefings, dosimetry, ALARA Plan and RWP requirements, electronic dosimetry, etc.). The worker did not perform the RWP process auto-sign-in on the RWP, which would have electronically checked the worker's 700 mrem administrative RWP buffer. Not performing this auto-sign-in process did not violate the primary means of controlling access and did not invalidate the RWP for the job. The RWP stated that 700 mrem dose availability was required prior to entry. This administrative dose buffer is an additional defense-in-depth, licensee-initiated control to protect against exceeding the licensee's system of dose control and is not utilized to control dose. The worker's actual dose did not exceed the electronic dosimeter set point and the minimum administrative control guideline. The dose availability of the worker is defined as the difference between the site-specific administrative control level of 2000 mrem (significantly below Federal Limits) and the worker's current accumulated dose for the year.</u> <u>An ALARA Plan and RWP controlled the work activity. The individual used teledosimetry with predetermined alarm setpoints for the job, which transmitted dose and dose rate information during the entry. Video surveillance was utilized by radiation protection technicians and in compliance with 10CFR20.1601(b) during the entry into the >1R/hr area. Specific authorization was given by the remote monitoring station technician to enter into the area. The worker had the training and respiratory protection qualifications required by the RWP, multiple TLDs had been issued, the required RWP was obtained and signed, and briefings were attended. The RWP entry was accomplished within pre-determined stay-time limitations, as discussed in the worker briefing. The electronic entry time was</u>	3/25 Introduced 4/22 Being revised by licensee <u>5/27 Revised</u>	TMI

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		entered after the worker had exited the area. There was no over exposure or unintended dose for this worker. The work was completed within the maximum projected dose for the activity. Technical Specification requirements for control of entry into the high radiation area were met and worker dose was controlled since the worker was authorized and had obtained the RWP for the job. The primary means of control of occupational dose exposure include pre-determined stay-time limitations and alarming dosimetry set below expected job levels. The administrative control level is an additional exposure control mechanism. The licensee's administrative control level is conservatively established at 2 rem, or 40% of the Federal dose limit, to provide a substantial margin to prevent personnel from exceeding the Federal dose limit of 5 rem and to help ensure equitable distribution of dose among workers with similar jobs. The individual's annual dose was well below 2 rem and the administrative control level had not been raised above 2 rem prior to the worker obtaining a TLD. If needed, additional and higher levels of managerial review and authorization are required for higher dose control levels. Increasing levels of management review and approvals are required to exceed the administrative control level of 2000 mrem (i.e., to 3000 mrem requires written approval by the Radiation Protection Manager and the work group supervisor, to 4000 mrem requires written approval by the Radiation Protection Manager, work group supervisor, and Plant Manager, to 5000 mrem requires written approval by the Site Vice President). The administrative dose buffer is in addition to the Technical Specification requirements for an RWP and therefore not material to the Technical Specification requirements for control of occupational dose. As it is stated in NEI 99-02, "this PI does not include nonconformance with licensee-initiated controls that are beyond what is required by technical specifications and the comparable provisions in 10CFR Part 20." The check of dose availability is a licensee-initiated administrative control that is beyond what is required by technical specifications, comparable provisions in 10CFR20, or Regulatory Guide 8.38. Does failure of the worker to meet the internal administrative control guideline for dose available as specified by the RWP for the job activity count as a PI occurrence?		
		Response: No, this event constitutes a procedural failure to meet a licensee-initiated administrative control; however, this event would not be a PI occurrence. Such an event would be reviewed under the appropriate NRC inspection criteria.		
37.6	BI02	Question: River Bend Station (RBS) seeks clarification of BI-02 information contained in NEI 99-02 guidance, specifically page 80, lines 36 and 37 *"Only calculations of RCS leakage that are computed in accordance with the calculational methodology requirements of the Technical Specifications are counted in this indicator."* NEI 99-02, Revision 2 states that the purpose for the Reactor Coolant System (RCS) Leakage Indicator is to monitor the integrity of the reactor coolant system pressure boundary. To do this, the indicator uses the identified leakage as a percentage of the technical specification allowable identified leakage. Moreover, the definition provided is "the maximum RCS identified leakage in gallons per minute each month per technical specifications and expressed as a percentage of the technical specification limit." The RBS Technical Specification (TS) states "Verify RCS unidentified LEAKAGE, total LEAKAGE, and unidentified LEAKAGE increase are within limits (12 hour frequency)." RBS accomplishes this surveillance requirement using an approved station procedure that requires the leakage values from the 0100 and 1300 calculation be used as the leakage "of record" for the purpose of satisfying the TS surveillance requirement. These two data points are then used in the population of data subject to selection for performance indicator calculation each quarter (highest monthly value is used).	3/25 Introduced 4/22 Discussed	River Bend

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		The RBS approved TS method for determining RCS leakage uses programmable controller generated points for total RCS leakage. The RBS' programmable controller calculates the average total leakage for the previous 24 hours and prints a report giving the leakage rate into each sump it monitors, showing the last four calculations to indicate a trend and printing the total unidentified LEAKAGE, total identified LEAKAGE, their sum, and the 24 hour average. The programmable controller will print this report any time an alarm value is exceeded. The printout can be ordered manually or can be automatic on a 1 or 8 hour basis. While the equipment is capable of generating leakage values at any frequency, the equipment generates hourly values that are summarized in a daily report. The RBS' TS Bases states "In conjunction with alarms and other administrative controls, a 12 hour Frequency for this Surveillance is appropriate for identifying changes in LEAKAGE and for tracking required trends." The Licensee provides that NEI 99-02 requires only the calculations performed to accomplish the approved TS surveillance using the station procedure be counted in the RCS leakage indicator. In this case, the surveillance procedure captures and records the 0100 and 1300 RCS leakage values to satisfy the TS surveillance requirements. The NRC Resident has taken the position that <u>all</u> hourly values from the daily report should be used for the RCS leakage performance indicator determination, even though they are not required by the station surveillance procedure. The Resident maintains that all hourly values use the same method as the 0100 and 1300 values and should be included in the leakage determination. Is the Licensee interpretation of NEI 99-02 correct?		
		Response: Yes. It was never the intent of the guidance to require all leakage determinations to be used for this performance indicator. Only those calculations that are performed to meet the requirements of the technical specification surveillance should be considered.		
37.8	IE03	Question: Frazil icing is a condition that is known to occur in northern climates, under certain environmental conditions involving clear nights, open water, and low air temperatures. Under these conditions the surface of the water will experience a super-cooling effect. The super-cooling allows the formation of small crystals of ice, frazil ice. Strong winds also play a part in the formation of frazil ice in lakes. The strong winds mix the super-cooled water and the entrained frazil crystals, which have little buoyancy, to the depths of the lake. The submerged frazil crystals can then form slushy irregular masses below the surface. The crystals will also adhere to any submerged surface regardless of shape that is less than 32°F. In order to prevent the adherence of frazil ice crystals to the intake structure bars and ensure maintenance of the ultimate heat sink, the bars of the intake structure are continuously heated. Surveillance tests conducted before and after the event confirmed the operability of the intake structure deicing heaters. While heating assists in preventing formation of frazil ice crystals directly on the bars of the intake structure, the irregular slushy masses discussed above can be drawn to the intake structure in quantities that reduce flow to the intake canal. If the flow to the intake canal is restricted in this manner, then the circulating (lake) water flow must be reduced, to allow frazil ice formations to clear. This water flow reduction necessitates a reduction of reactor power. The plant had previously put procedural controls in place to monitor the potential for frazil ice formation during periods of high susceptibility. A surveillance test requires evaluating the potential for frazil ice formation during the winter months, when intake temperature is less than 33°F. In support of the surveillance test, the Chemistry Department developed a test procedure for assessing the potential for frazil ice formation. An abnormal operating procedure was developed to mitigate the consequences of an event should frazil icing reduce the flow through the	4/22 Introduced and Tentative Approval	FitzPatrick

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		intake structure. During the overnight hours between February 14, and February 15, 2004 the environmental conditions were conducive to the formation of frazil ice. Chemistry notified Operations that the potential for frazil icing was very high. Operators were briefed on this condition, the very high potential for frazil ice formation, and the need to closely monitor intake level. When indications showed a lowering intake canal level with no other abnormalities indicated, operations reduced power from 100% to approximately 30% per procedure so that circulating water pumps could be secured, thereby reducing flow through the intake structure heated bars, to slow the formation or accumulation of frazil ice and allow melting of the ice already formed. NEI 99-02, in discussing downpowers that are initiated in response to environmental conditions states "The circumstances of each situation are different and should be identified to the NRC in a FAQ so that a determination can be made concerning whether the power change should be counted." Does the transient meet the conditions for the environmental exception to reporting Unplanned Power changes of greater than 20% RTP?		
		Response: Yes, the downpower was caused by environmental conditions, beyond the control of the licensee, which could not be predicted greater than 72 hours in advance.		
37.9	EP02	Question: NEI 99-02 Rev 2 ERO Participation PI defines the numerator and denominator of the calculation as based on Key ERO Members. The list was originally created from the NUREG-0654 Table B-1 positions that involved actions associated with the risk significant planning standards (classification, notification, PARs, and assessment), with the addition of the Key OSC Operations Manager included from a mitigation perspective. It is understood that when a single individual is assigned in more than one 'key position' they must be counted individually for each position (page 91 lines 4-7 of NEI 99-02). Guidance is not provided in the case where key positions are not unique to separate ERO members. For example, the communicator is defined in NEI 99-02 as the individual that fills out the notification form, seeks approval and usually communicates the information to off site agencies (these duties may vary from site to site based on site procedures). When the communicator activity is performed by an ERO member who is also defined by another key position (i.e., the Shift Manager), should participation be counted individually for each function or collectively for the single member?	4/22 Introduced 5/27	generic
		Response: Yes, participation should be counted as individual opportunities for each key ERO function, even when the key ERO function is performed by the same qualified ERO member. In the case where a utility has combined the functions of the qualified ERO members as defined in the NEI guidance under a single position, those key ERO functions must be counted as separate opportunities in the denominator for each qualified ERO member and credit given in the numerator when the qualified ERO member performs each individual key ERO function. This indicator provides linkage to the DEP PI, measuring the individuals who have performed the key ERO function over all of the assigned qualified ERO members. Assigning a single member to multiple functions and then only counting the performance for one function could mask the ability or proficiency of the remaining functions. The concern is that an ERO member having multiple functions may never have a performance enhancing experience for all of them, yet credit for participation will be given when any one of the multiple functions is performed; particularly, if more than one ERO position is assigned to performed the same function.		
38.1	MS01	Question:	4/22 Introduced	Waterford

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		This FAQ seeks clarification of the guidance in NEI 99-02 regarding fault exposure. Specifically, NEI 99-02, page 30, lines 3-6 describe fault exposure (T) in terms of failure and the failure's known time of occurrence and known time of discovery. Lines 13-20 provide "T/2" fault exposure guidance where the time of failure is uncertain and only the time of discovery is known. This clarification will be used to determine whether a situation is "T" or "T/2." Emergency diesel generator "A" (EDG A) failed a monthly surveillance on September 29, 2003. A fuel oil line connection on the diesel failed during the surveillance; the surveillance was halted and the diesel declared inoperable. Based upon guidance in NEI 99-02 and FAQ 318, the plant reported in the 3Q03 performance indicator submittal T/2 fault exposure hours based upon the time from the last successful surveillance (September 2, 2003) until EDG A failed on September 29, 2003. This is due largely to the guidance that notes "*...Fault exposure hours for this case must be estimated. The value used to estimate the fault exposure hours for this case is: one half the time since the last successful test or operation that proved the system was capable of performing its safety function.*" Is this interpretation of the guidance correct? Additional Details: A root cause determined that plant maintenance introduced a latent condition on May 16, 2003 during maintenance on the diesel that lead to EDG A failure during the September 29 surveillance. The root cause established the failure mechanism was fatigue. A time of failure after the introduction of the latent maintenance condition cannot be predicted with certainty because of the complexity of the fatigue phenomenon e.g., fatigue failure is a non-linear function of time; it is also cumulative. The fatigue failure was further complicated by multiple starts and stops of the diesel during monthly surveillances. (From the time the tubing was installed in May 2003, EDG A ran for almost 29 hours over a period of about 4 months and 5 successful surveillances.) NRC inspection noted "the finding is a potential reporting error concerning the Emergency AC Power System Unavailability performance indicator," i.e., that T fault exposure hours should apply based upon the time of the maintenance in May until the diesel was returned to service in September.		
		Response For this situation, the Licensee interpretation is correct that T/2 should apply. The fatigue failure mechanism for this case is sufficiently uncertain such that the loss of safety function cannot be predicted with certainty prior to the last successful surveillance of the diesel. It should be noted that reporting T/2 hours ensures that NRC is aware of a failure that potentially warrants inspection; this situation has been inspected.		
38.2	MS01, MS04	*Question:* If the emergency AC power system or the residual heat removal system is not required to be available for service (e.g., the plant is in "no mode" or Technical Specifications do not require the system to be operable), is it appropriate to include this time in the "hours train required" portion of the safety system performance indicator calculation? NEI 99-02, Revision 2, starting on line 25 of page 33, discusses the term "hours train required" as used in safety system unavailability performance indicators. For the emergency AC power system and residual heat removal system, the guidance allows the "hours train required" to be estimated by the number of hours in the reporting period because the emergency generators are normally expected to be available for service during both plant operations and shutdown, and because the residual heat removal system is required to be available for decay heat removal at all times. The response to FAQ 183 states: "During periods and conditions where Technical Specifications allow both shutdown cooling trains to be removed from service the shutdown cooling system is, in effect, not required and required hours and unavailable hours would not be counted."	5/27 introduced	

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		Response: NRC: During periods and conditions where Technical Specifications allow all trains of a system to be removed from service the system is, in effect, not required and required hours and unavailable hours would not be counted Industry: FAQ 183referred to plant specific technical specifications of an RHR system, and was listed in NEI 99-02Rev 1. Appendix E, "Frequently Asked Questions," as an Appendix D (plant specific) FAQ. The text of NEI 99-02 was not changed in either Rev 1 or 2 to apply this answer to all plants. It also did not apply to Emergency Diesel Generators. On a going forward basis, however, during periods and conditions when Technical Specifications allow all trains of a system to be removed from service, the system is in effect not required and required hours and unavailability hours would not be counted. Rev. 3 of NEI 99-02 will be modified to incorporate this change in guidance.		