Attachment 3

# REACTOR OVRSIGHT PROCESS
# WORKING GROUP ACTION LIST – Status August 19, 2004

The following is the current listing of action items:

| OPEN Action Items | Description | Due Date |
|---|---|---|
| 04-05 | **Safety System Functional Failure (MS05) Reconciliation Project**<br>Task: NRC provided the docket number and corresponding Licensee Event Reports (LER) for which the NRC's contractor assessed the LER as being a Safety System Functional Failure (SSFF: MS05). Industry is reviewing this data against ROP reported data and will provide an analysis of differences.<br>Status: *Initial review of all contractor LER-evaluations complete; results provided to individual licensees for reconciliation/additional-information. Licensee feedback being evaluated. Expect industry draft report at September 16 meeting.* | *9/16/04* |
| 04-09 | **Maintenance Rule Workshop**<br>Task: NRC is considering holding a workshop on the new Maintenance Rule SDP. Doug Coe will go over the issues raised by industry, and determine whether a meeting is appropriate. Decision whether a workshop would be appropriate will be made in several months.<br>Status: *Open- Doug Coe to determine if workshop is necessary.* | *OPEN* |
| 04-13 | **Fire Protection SDP Review**<br>Task: NRC Review process for fire protection SDPs has no apparent feedback (to licensees) provided from the NRC panel meetings.<br>Status: *Review process on the Fire Protection SDP panel and determine (and report back) how will have feedback provided from the panel meetings.* | *OVERDUE* |
| 04-16 | **NEI 99-02 Revision 3**<br>Task: NEI (Tom Houghton) to provide a consolidated "for comment draft" (for further review/comment) by the September 16 meeting. The overall goal will be to develop a final Rev3 by December 2004.<br>Status: NRC comments received; work proceeding on incorporation of FAQs and Appendix E on FAQ process | *12/31/04* |
| 04-17 | **Mitigating Systems Performance Index**<br>Task: NRC Commission has directed the NRC staff to work together with industry to resolve the issues associated with the MSPI.<br>Status: *NRC to provide a letter to NEI confirming intention of proceeding with MSPI with targeted implementation date of 1/1/06* | *8/31/04* |
| 04-18 | **Licensee Identified versus Self-Revealing Events**<br>Task: NRC to evaluate the MC 0612 criteria on "self identified" versus "self-revealing" | *09/30/04* |
| 04-19 | **Resolution of old IE02 FAQs**<br>Task: Discussed the seven FAQs (27.3, 28.3, 30.8, 32.3a, 34.6, 36.1, and 36.2) which involve SCRAMS with loss of normal heat removal Industry proposed in the April meeting that NRC consider dropping these FAQs since (1) they involve specific conflicting guidance in NEI 99-02; (2) NRC has already assessed each scram, sometimes with a special inspection. NRC agreed to review the NEI data and determine next steps.<br>Status: *NRC to consider NEI proposal to drop these FAQs* | *Open* |

| OPEN Action Items | Description | Due Date |
|---|---|---|
| 04-20 | **Maintenance Rule and MSPI**<br>Task: a white paper from NEI/Industry explaining why it is acceptable to change NUMARC 93-01 to stop monitoring unavailability when subcritical. NRC contact: Steve Alexander<br><br>Status: NEI developing white paper | OPEN |
| 04-21 | **MSPI Lessons Learned Evaluation**<br>Task: Industry has requested NRC support a joint "lessons learned" team to examine the MSPI Pilot Program for lessons learned – to improve future management and administration of future PI Pilot Programs and development of future indicators.<br>Status: Under consideration | OPEN |
| 04-22 | **SECURITY IN THE ROP**<br>Task: NSIR will be asked to come to present information on the status of including Security issues in security (Action Matrix, PIs, etc.) and the status of the Security SDP. | OPEN |
| 04-23 | **ISFSI**<br>Task: Industry inquired as to the status of ISFSI facilities within the ROP inspection program. | OPEN |

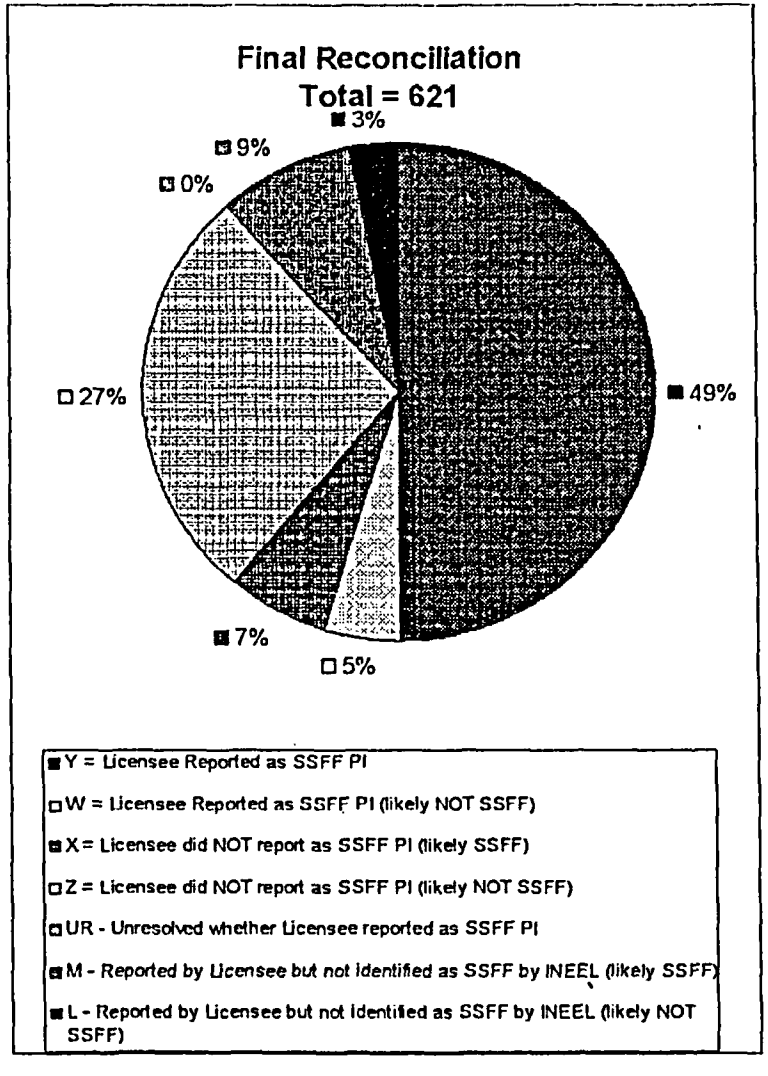
| CLOSED Action Items | Description | Due Date |
|---|---|---|
| 04-01 | **RCS Leakage PI (B02)**<br>Task: INDUSTRY/NRC to establish task force to explore feasibility of new replacement metric. Closed.<br>Status: *August 19 meeting formed a subgroup.* | CLOSED |
| 04-02 | **Steam Generator SDP**<br>Task: INDUSTRY– Provide examples of "minor" steam generator issues/results/findings by the March meeting<br>Status: *Examples provided and NRC to include appropriate examples in MC 0612 Appendix E.* | *Closed* |
| 04-03 | **Maintenance Rule SDP**<br>Task: Provide written comments on the Maintenance Rule SDP by the March meeting.<br>Status: *Example/comments provided and NRC to include in final SDP.* | *Closed* |
| 04-04 | **SDP Lessons Learned**<br>Task: NRC and Industry brought SDP timeliness examples to the meeting. Industry to evaluate these examples for inclusion as case studies in an SDP workshop devoted to improving SDP timeliness. Industry to review schedule to support a summer workshop.<br>*Status: Workshop targeted for for mid-July. NRC to confirm dates and NEI to send out letter to APCs announcing workshop. Rescheduled for September.* | *Closed* |
| 04-06 | **Graded Reset of Action Matrix Inspection Findings**<br>Task: NRC to provide the resolution (answer) to the graded reset question raised by Industry by the March meeting and in FRN comments on the ROP.<br>Status: NRC provided response. While closed, Industry intends to continue to pursue via other channels. | *Closed* |
| 04-07 | **NRC Comments on Generic Changes in NEI 99-02 (Revision 3)**<br>Task: NRC to provide a listing of sections within NEI 99-02 Rev 2 that contain ambiguous or unclear guidance that the NRC has identified as needing modification when drafting Rev 3 by March meeting. This is to be subsumed within 04-16 when NRC comments received.<br>*Status: NRC provided comments to NEI for consideration. The approved FAQs, and a new Appendix E FAQ process.* | *Closed* |
| 04-08 | **Industry Trends Report**<br>Task: NRC will provide the Industry Trends Report when available.<br>*Status: Received* | *Closed* |
| 04-10 | **Ginna FAQ**<br>Task: Licensee to review their previous FAQ and determine if their closing of the MSIVs (early on in the post trip recovery) is still applicable, or if their process has changed and the FAQ is no longer appropriate to apply [Licensee responded that the process has not changed – Open for discussion in May meeting].<br>*Status: Licensee has provided input To be discussed at June ROP meeting* | *Closed* |
| 04-11 | **Revised FAQ Process**<br>Task: Provided NRC with current draft of FAQ process.<br>*Status: NEI is incorporating comments into Appendix E of NEI 99-02* | *OPEN* |

| CLOSED Action Items | Description | Due Date |
|---|---|---|
| 04-01 | **RCS Leakage PI (B02)**<br>Task: INDUSTRY/NRC to establish task force to explore feasibility of new replacement metric. Closed.<br>Status: *August 19 meeting formed a subgroup.* | CLOSED |
| 04-12 | **Replacement Metric for SCRAMS wlonhr (IE02)**<br>Task: NRC and Industry to develop a proposed replacement indicator for existing IE02 metric.<br>*Status: . August 19 meeting formed a subgroup.* | *Closed* |
| 04-14 | **NRC FAQ Feedback Process**<br>Task: NRC to examine their internal feedback form process and how it should be included in the FAQ process.<br>*Status: NRC has agreed to initiate FAQs for all NRC feedback forms related to NEI 99-02 interpretation issues. This item will be folded into Action 04-11 upon completion of draft FAQ process.* | *Closed* |
| 04-15 | **Mitigating Systems PIs – No Mode**<br>Task: NRC to prepare an FAQ on how to account for "No Mode" hours in MS04 PI.<br>*Status: This would be a going forward FAQ.* | *Closed* |

Draft

Draft – Preliminary Results August 18, 2004

| | Prelim | Final |
|---|---|---|
| Y = Licensee Reported as SSFF PI | 283 | 311 |
| W = Licensee Reported as SSFF PI (likely NOT SSFF) | 32 | 28 |
| X = Licensee did NOT report as SSFF PI (likely SSFF) | 93 | 41 |
| Z = Licensee did NOT report as SSFF PI (likely NOT SSFF) | 118 | 169 |
| UR - Unresolved whether Licensee reported as SSFF PI | 26 | 0 |
| M - Reported by Licensee but not Identified as SSFF by INEEL (likely SSFF) | 76 | 53 |
| L - Reported by Licensee but not Identified as SSFF by INEEL (likely NOT SSFF) | 0 | 19 |
| TOTAL | 552 | 621 |




A Hachmeister

Attachment 5

# RCS LEAKAGE PI TASK FORCE
# CHARTER

Task Force Composition: The RCS Leakage PI Task Force will be composed of two or three persons from the NRC staff and two or three persons from industry organizations.

Requirements: All members of the task force will have experience with the ROP performance indicators in general and with the RCS leakage PI in particular.

Product: The task force will produce a report documenting the group's findings in the following areas:

a. Recommendation for the purpose of the PI;
b. Discussion of the various plant-specific technical specifications on RCS leakage;
c. Discussion of the various plant-specific leakage measurement systems;
d. Recommendation for a PI definition given the existing measurement systems and technical specifications;
e. Recommendations for thresholds, given d above;
f. Recommendations for longer-term changes that could be made that would result in a better PI.

Meeting Schedule: The task force will convene at least bi-weekly, either in person or by teleconference. The first meeting shall take place no later than September 3, 2004.

Interim Reports: The task force will provide an interim report at each regularly scheduled meeting of the NRC/Industry working group.

Final Report: The final report will be delivered to the working group no later than the regularly scheduled working group meeting in January 2005.

Attachment 6

# SCRAMS w/LOSS OF NORMAL HEAT REMOVAL PI TASK FORCE CHARTER

Task Force Composition: The Scrams w/Loss of Normal Heat Removal (SwLONHR) PI Task Force will be composed of two or three persons from the NRC staff and two or three persons from industry organizations.

Requirements: All members of the task force will have experience with the ROP performance indicators in general and with the SwLONHR PI in particular.

Product: The task force will produce a report documenting the group's findings in the following areas:

a. Recommendation for the purpose of the PI;
b. Results of a survey of all licensees to determine the status of the power conversion system following a reactor scram;
c. Recommendation for a PI definition;
d. Recommendations for thresholds, given c above;
e. Recommendations for longer-term changes that could be made that would result in a better PI.

Meeting Schedule: The task force will convene at least bi-weekly, either in person or by teleconference. The first meeting shall take place no later than September 10, 2004.

Interim Reports: The task force will provide an interim report at each regularly scheduled meeting of the NRC/Industry working group.

Final Report: The final report will be delivered to the working group no later than the regularly scheduled working group meeting in March 2005.

Attachment 7

**EMERGENCY PREPAREDNESS CORNERSTONE**
**ANS PI FAQ**

**Question:**

If a licensee makes a change in ANS testing methodology, when can that change be used in the ANS PI calculation?

**Answer:**

The change may not be used in the ANS PI calculation until the beginning of the next quarter. This is consistent with NEI 99-02, pg 94, lines 12-13, that states: "Periodic tests are the regularly scheduled tests..." Thus, the regularly scheduled test methodology that was used at the beginning of the quarter is to be used throughout the quarter for input to the ANS PI data. This is necessary to ensure the consistency and validity of the quarterly ANS PI data. As a reminder, if the change in ANS test methodology is considered to be a significant change per FEMA requirements, the change is required to have FEMA approval prior to implementation.

Attachment 8

IMPACT OF NO MODE ON MS01 and MS04

initial unavail hours/(26280- no mode hours) = Final % unavail
AND
Initial unavail hours = (26280) (initial % unavail)
Then
(26280) (initial % unavail) / (26280 - no mode hours) = final % unavail
AND
no mode hours = 26280 [ 1 - (initial %/final %)]

FOR EDG CASE (threshold is 2.5%)

| initial ua | final ua | no mode hrs | no mode days |
|---|---|---|---|
| 0.02 | 0.021 | 1251 | 52.1 |
| 0.021 | 0.022 | 1195 | 49.8 |
| 0.022 | 0.023 | 1143 | 47.6 |
| 0.023 | 0.024 | 1095 | 45.6 |
| 0.024 | 0.025 | 1051 | 43.8 |
| 0.025 | 0.026 | 1011 | 42.1 |
| avg init ua | | | |
| 0.01 | 0.011 | 2389 | 99.5 |

FOR RHR CASE (threshold is 1.5%)

| initial ua | final ua | no mode hrs | no mode days |
|---|---|---|---|
| 0.01 | 0.011 | 2389 | 99.5 |
| 0.011 | 0.012 | 2190 | 91.3 |
| 0.012 | 0.013 | 2022 | 84.2 |
| 0.013 | 0.014 | 1877 | 78.2 |
| 0.014 | 0.015 | 1752 | 73.0 |
| 0.015 | 0.016 | 1643 | 68.4 |
| avg init ua | | | |
| 0.007 | 0.008 | 3285 | 136.9 |

| TempNo. | PI | Question/Response | Status | Plant/ Co. |
|---|---|---|---|---|
| 27.3 | IE02 | Question:<br>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<br>Background Information:<br>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."<br><br>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).<br><br>Verify the following:<br>TDRFP M/A XFER (Manual/Automatic Controller) station is reset to Minimum<br>No TDRFP trip signals are present<br>Depress TDRFP Turbine RESET pushbutton and observe the following<br>Turbine RESET light Illuminates<br>TDRFP High Pressure and Low Pressure Stop Valves OPEN<br>PUSH M/A increase pushbutton on the Manual/Automatic Controller station<br>Should this be considered a scram with the loss of normal heat removal?<br><br>Proposed Answer:<br>The ROP working group is currently working to prepare a response. | 1/25 Introduced<br>2/28 NRC to discuss with resident<br>4/25 Discussed<br>5/22 On hold<br>6/12 Discussed. Related FAQ 30.8<br>9/26 Discussed<br>10/31 Discussed | LaSalle |
| 28.3 | IE02 | Question:<br>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.<br><br>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.<br><br>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<br>4/25 Discussed<br>5/22 Modified to reflect discussion of 4/25, On Hold<br>6/12 Discussed. Related FAQ 30.8 | Perry |

Attachment 5

| TempNo. | PI | Question/Response | Status | Plant/ Co. |
|---|---|---|---|---|
| | | (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.<br><br>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.<br><br>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?<br>Response:<br>The ROP working group is currently working to prepare a response. | | |
| 30.8 | IE02 | Question:<br>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?<br>Response:<br>The ROP working group is currently working to prepare a response. | 5/22 Introduced<br>6/12 Discussed<br>9/26 Discussed.<br>10/31 Discussed | Generic |
| 32.3a | IE02 | Question:<br>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.<br>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 supply. | 1/23 Revised. Split into two FAQs<br>3/20 Discussed<br>5/1 Discussed<br>5/22 Tentative Approval<br>6/18 Discussion deferred to July<br>7/24 Discussed | DC Cook |

| TempNo. | PI | Question/Response | Status | Plant/ Co. |
|---|---|---|---|---|
| | | 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.<br>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.<br>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.<br>Should the reactor trip described above be counted in the Unplanned Scrams with Loss of Normal Heat Removal Performance Indicator? | | |
| | | Response:<br>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.<br>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:<br>Should the following event be counted as a scram with loss of normal heat removal? | 3/20 Introduced<br>3/20 Discussed | STP |

| TempNo. | PI | Question/Response | Status | Plant/ Co. |
|---|---|---|---|---|
| | | 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.<br>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.<br>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.<br>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"*.<br>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.<br>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 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. | 6/18 Discussed; Question to be revised to reflect discussion<br>7/24 Discussed | |

| TempNo. | PI | Question/Response | Status | Plant/ Co. |
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| | | 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.<br>Response:<br>The ROP working group is currently working to prepare a response.<br>Licensee Proposed Response:<br>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:<br>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).<br>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.<br>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.<br>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.<br>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.<br>Does this scram constitute a scram with a loss of normal heat removal?<br>Response:<br>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 | 9/25 Introduced and discussed | Quad Cities |

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| | | 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.<br>Further supporting information:<br>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.<br>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:<br>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?<br>Description of Event:<br>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.<br>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.<br>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.<br>**Problem Assessment:**<br>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 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.<br>Reopening of the MSIVs was: | 9/25 Introduced and discussed | Peach Bottom |

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| | | • easily facilitated by restarting Reactor Building ventilation,<br>• completed from the control room using normal operating procedures<br>• without the need of diagnosis or repair<br>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.<br>Discussion of specific aspects of the event:<br>Was the recognition of the condition from the Control Room?<br>▪ 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.<br>Does it require diagnosis or was it an alarm?<br>▪ The event is annunciated in the control room as described previously.<br>Is it a design issue?<br>▪ 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.<br>Are actions virtually certain to be successful?<br>▪ 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.<br>Are operator actions proceduralized?<br>▪ 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.<br>How does Training address operator actions?<br>▪ The actions necessary for responding to a Group I isolation and subsequent recovery of the Main Steam system are covered in licensed operator training.<br>Are stressful or chaotic conditions during or following an accident expected to be present?<br>• 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 | | |
| | | Response:<br>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:<br>On August 14, 2003 Ginna Station scrammed due to the wide spread grid disturbance in the Northeast United States. | 1/22 Introduced<br>3/25 Discussed | Ginna |

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| | | 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?"<br><br>Response:<br>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).<br><br>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. | 6/16 Discussed | |
| 36.9 | IE02 | Question:<br>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 increased 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 feedwater pumps to trip. Following the reactor SCRAM, the operators manually started the auxiliary feedwater pumps to supply feedwater to the steam generators.<br>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 | 1/22 Introduced<br>3/25 Discussed. Question to be rewritten and response provided<br>4/22 Question and response provided<br>6/16 Discussed<br>7/22 Discussed | Millstone 2 |

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| | | 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.<br>Does this SCRAM count against the performance indicator for scrams with loss of normal heat removal?<br>Response:<br>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 were 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:<br>The definition of the Occupational Exposure Control Effectiveness performance indicator refers to "measures that provide assurance that inadvertent entry into the technical specification high radiation areas by unauthorized personnel will be prevented" (page 98, NEI 99-02, Revision 2). In the context of applying the performance indicator definition in evaluating physical barriers to control access to technical specification high radiation areas, what is meant by "inadvertent entry"?<br>Response:<br>In reference to application of the performance indicator definition in evaluating physical barriers, the term "inadvertent entry" means that the physical barrier can ~~should~~ not ~~be able to~~ be easily circumvented ~~–~~(i.e.,~~the barrier should secure an area against unauthorized access. However, the performance indicator specifically excludes consideration of postulated unauthorized access scenarios that would involve a willful violation of licensee measures in place to control access to the area, such as training, posting, radiation work permits, procedures, and barriers. Such a willful violation is outside the scope of the performance indicator.~~ an individual who incorrectly assumes, for whatever reason, that he or she is authorized to enter the area, is unlikely to disregard, and circumvent, the barrier). The barriers used to control access to technical specification high radiation areas should provide reasonable assurance that they secure the area against unauthorized access. | 3/25 Introduced<br>4/22 Directed to HP counterparts for review<br>5/27 To be revised by HP counterparts<br>7/22 Revised | NRC |
| 37.5 | OR1 | Question:<br>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.<br><br>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 entered after the | 3/25 Introduced<br>4/22 Being revised by licensee<br>5/27 Revised To be reviewed by HP counterparts | TMI |

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| | | 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.<br><br>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.<br><br>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:<br>Yes this event would be a reportable PI occurrence. The above clearly describes a nonconformance with an RWP procedural requirement that resulted in a loss of control of access to the Tech. Spec. High Radiation Area. Had the RWP procedure been adhered to, this individual would not have been allowed to enter without further approval. ~~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:<br>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."*<br><br>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."<br><br>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 | 3/25 Introduced<br>4/22 Discussed<br>5/27 Discussed | River Bend |

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| | | "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).<br><br>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.<br><br>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."<br><br>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.<br><br><u>Is the Licensee interpretation of NEI 99-02 correct?</u><br><br>Response:<br>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. | | |
| 37.9 | EP02 | Question:<br>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.<br><br>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).<br><br>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<br>5/27 Discussed. To be revised to reflect discussion.<br>7/22 EP peer experts to review this issue | generic |

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| | | Response:<br>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.<br><br>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. | | |
| 38.2 | MS01, MS04 | Question:<br>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?<br><br>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.<br>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<br>7/22 Discussed | |
| | | Response:<br>NRC:<br>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<br>Industry:<br>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. | | |
| 38.3 | MS01 | Appendix D FAQ: Mitigating Systems – Safety System Unavailability, Emergency AC Power<br>During a monthly surveillance test of Emergency Diesel Generator 3 (EDG3), an alarm was received in the control room for an abnormal condition. The jacket water cooling supply to EDG3 had experienced a small leak (i.e., less than 1 gpm) at a coupling connection that resulted in a low level condition and subsequent control room alarm. The Low Jacket Water Pressure Alarm, which annunciates locally and in the control room, indicated low pump suction pressure. This was due to low level in the diesel generator jacket water expansion tank. An Auxiliary Operator (AO) stationed at EDG3 responded to the alarm by opening the manual supply valve to provide makeup water to the expansion tank. | 6/16 Introduced<br>7/22 Discussed | Brunswick |

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| | | EDG3 continued to function normally and the surveillance test was completed satisfactorily. Review of data determined that improper tightening of the coupling was performed after the monthly EDG run on December 8, which led to an unacceptable leak if the EDG was required to run. The coupling was properly repaired and tested, and declared to be available and operable on January 6. The condition existed for approximately 28 days.<br>Although the recovery action was conducted outside of the main control room, it was a simple evolution directed by a procedure step, with a high probability of success. This operator response is similar to the response described in Appendix D FAQ 301. In addition, this operator action would be successful during a postulated loss of offsite power event, except for a 23 hour period when the demineralized water supply level was too low to support gravity feed. The engineering analysis determined that a level of 21' 5" of demineralized water supply level was necessary to support gravity feed to the expansion tank. Another 9" (4,740 gallons) was added to this level to allow for the leak and nominal usage and makeup over the 24 hour mission time. Using this analysis, any time the demineralized water level fell below 22" 2", the EDG was considered to be unavailable. A human reliability analysis calculated the probability of an AO failing to add water to the expansion tank from receipt of the low pressure alarm to be 4.7 E-3. In other words, there would be a greater than 99.5% probability of successful task completion within twenty minutes of receiving the annunciator. Vendor analysis determined that, with the existing leak rate, the EDG would remain undamaged for twenty minutes.<br>The human reliability analysis considered that the low jacket water pressure would be annunciated in the control room, the annunciator procedure provided specific direction for filling the expansion tank, the action is reinforced through operator training, and sufficient time would be available to perform the simple action. In its calculation of the probability of operator recovery, the analysis also considered that another indicator, a low-level expansion tank alarm was out-of-service during this time period. However, although the low expansion tank alarm was out of service, it results in low pump suction pressure which did annunciate.<br>NEI 99-02 Appendix D lists several issues that may be addressed for exceptions to allow credit for operator compensatory actions to mitigate the effects of unavailability of monitored systems.<br>1. The capability to recognize the need for compensatory actions – Low pump suction pressure annunciates in the control room.<br>2. The availability of trained personnel to perform the compensatory action – This is an uncomplicated action, but operators are trained on it. An auxiliary operator simply has to open one manual valve as directed by the annunciator procedure.<br>3. The means of communications between the control room and the local operator – Communications can be accomplished either via the plant PA system or a portable radio.<br>4. The availability of compensatory equipment – No compensatory equipment is necessary.<br>5. The availability of a procedure for compensatory actions – There is an annunciator procedure in the diesel generator room that would direct the auxiliary operator to open the manual valve.<br>6. The frequency with which the compensatory actions are performed – This action is performed infrequently, but it was demonstrated to be successful during the surveillance test.<br>7. The probability of successful completion of compensatory actions within the required time – The human reliability analysis determined that there was a 99.5% probability of successful completion of compensatory action within the required time.<br>In summary, over a 28-day period, jacket water cooling for EDG3 was degraded, but functional for approximately 27 days, and was totally unavailable for 23 hours. This is based on a review of Operator logs, plant trending computer points, and flow calculations. During the 27-day degraded period, a simple manual action directed by procedure and | | |

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| | | performed by an operator would have been used to ensure that jacket water was available.<br>Should fault exposure hours be reported for the 27 days when the Emergency Diesel Generator 3 jacket water was considered to be degraded but functional? | | |
| | | Response:<br>No. Unavailable hours need not be reported for this situation. The actions are proceduralized, operators are trained on the procedure, no troubleshooting or diagnosis is necessary, there is a control room alarm to alert the operators to the need for action, and the actions have been demonstrated to be able to be accomplished within the necessary time constraints. Therefore, operator recovery actions are considered to be virtually certain of success. | | |
| 38.4 | EP03 | Question:<br>Pilgrim has 112 sirens which are normally scheduled to be tested for performance indicator purposes once each calendar month (e.g., once during the month of September). This was reflected in procedure as a requirement to test all of the sirens "monthly". The person scheduling the testing of the sirens incorrectly interpreted the procedure's "monthly" frequency consistent with other "monthly" tests as allowing a 25% grace period for scheduling flexibility. As a result, 29 of the siren tests normally scheduled to be performed in September were scheduled to be performed during the beginning of October.<br>On October 1 the status of the siren testing was discussed with other members of the plant staff who understood that the intent of the "monthly" requirement was once per calendar month and that no grace period applied. Immediate actions were taken including performing the remaining 29 tests on an accelerated basis (all satisfactory tested by October 3) and entering the item in the corrective action program.<br>All of the 29 sirens passed the testing performed during the first 3 days of October. The testing was not delayed due to the unavailability or suspected unavailability of the sirens. The reason for the late testing of the equipment was purely an administrative error and not siren functionality related.<br>For plants where siren tests are initiated by the utility, if a scheduled test(s) was not performed due to an administrative issue but the untested siren(s) was not out-of-service for maintenance or repair and was believed to be capable of operation if activated, should the missed tests be considered non-opportunities or failures for performance indicator reporting purposes? | 6/16 Introduced | Pilgrim |
| | | Response:<br>Tests missed for reasons other than siren unavailability (e.g., out of service for maintenance or repair) should be considered non-opportunities. | | |
| 38.9 | OR01 | Question:<br>On March 4, 2004, workers initiated a series of diving activities related to the inspection and repair of the Steam Dryer in the Dryer Separator Pit. On March 5, 2004, a contract diver proceeded to the Unit 1 Reactor Building 117' Elevation in preparation for the next diving evolution on the Steam Dryer. Based on underwater dose gradients from the steam dryer, 5 Electronic Dosimeters (EDs), 10 thermoluminescent dosimeters (TLDs) and a telemetry transmitter were placed on the diver by a Radiation Protection Technician (RPT) to monitor personnel exposure. ED/TLD combinations were placed on the chest, right arm, left arm, right leg, and left leg. TLDs were use to monitor the extremities. Communication between the EDs and the telemetry system was verified after placement on the diver. The RPT conducted the pre-dive radiological briefing and the diver entered the Contaminated Area.<br>Telemetry problems were experienced prior to the diver entering the Dryer Separator Pit. The underwater antenna was changed out and telemetry problems appeared to be corrected. The diver was in the Dryer Separator Pit approximately 40 minutes when additional telemetry problems occurred. The diver was instructed to exit the water and the transmitter replaced. The telemetry problems were corrected and the diver re-entered the Dryer Separator Pit. After entering the water, the left arm ED stopped communicating with the telemetry system. The telemetry computer was rebooted while the diver was in the Dryer Separator Pit, but the left arm ED failed to transmit. The RP Supervisor evaluated the situation and decided to allow the dive to continue since four of the five EDs were transmitting properly. | 7/22 Introduced | Brunswick |

| TempNo. | PI | Question/Response | Status | Plant/ Co. |
|---|---|---|---|---|
| | | The left arm ED did not transmit for the remainder of the dive. However, it did remain functional and continued to accumulate dose. Upon completion of the work, the diver exited the Dryer Separator Pit and it was discovered that his left arm ED was in alarm. Specific ED results for the diver are given below: | | |

| ED Location | ED Result (mrem) |
|---|---|
| Chest | 147 |
| Right Arm | 319 |
| Left Arm | 588 |
| Right Leg | 30 |
| Left Leg | 31 |

Per the RWP, ~~the ED~~ the Administrative Dose Limit for the dive was 500 mrem.
The diver's TLDs were processed and the results are given below

| TLD Location | TLD Result (mrem) |
|---|---|
| Chest | 135 |
| Right Arm | 403 |
| Left Arm | 673 |
| Right Leg | 30 |
| Left Leg | 34 |
| Head | 216 |

Does the situation described above constitute an unintended exposure occurrence in the Occupational Radiation Safety Cornerstone as described in NEI 99-02?

Response:
NEI 99-02 identifies the dose value used as a screening criterion to identify an unintended exposure occurrence as 100 mrem. The administrative dose guideline was established in the RWP as 500 mrem. Since the ED was functional and read 588 mrem, the screening criterion in 99-02 was not exceeded.

| | | | | |
|---|---|---|---|---|
| 39.1 | IE03 | Question:<br>On June 23, 2004, condenser waterbox level and temperature readings on the Unit 1 and 2 main condensers indicated partial blockage of the waterbox intake debris filters. The cause was an influx of gracilaria, which is a marine grass found in the river water that is the circulating water intake supply to the plant. Subsequent backwashes of the debris filters were successful at restoring waterbox level and temperature readings to the normal band, except for the 2B-South waterbox, which is one of four waterboxes of the Unit 2 main condenser. An extended backwash was unsuccessful in restoring its readings back to normal.<br>Debris is removed prior to entering the circulating water intake bay by traveling screens with spray nozzles. The 2B-South debris filter is directly downstream from the 2D traveling screen. Investigation of this event found that the spray nozzles for the 2D traveling screen had more fouling than the other spray nozzles. The 2D traveling screen was able to adequately remove normal debris loading, but was not as effective as the other spray nozzles in removing the debris during the large influx of gracilaria.<br>A decision was made on June 24, 2004 to reduce power to about 53% and isolate the 2B-South waterbox to clean its debris filter. The decision to reduce power within 24 hours was based on several factors, such as reduced condenser efficiency, the potential for additional debris filter clogging, and a reduction in reactor water chemistry due to elevated condensate demineralizer resin temperatures. It was also based on input from work management, operations, and the load dispatcher. The 2B-South waterbox was successfully cleaned during the downpower and reactor power was restored to normal operating conditions.<br>This was an anticipated power change in response to expected conditions. Operating experience has shown that the | 8/18 Introduced | Brunswick |

| TempNo. | PI | Question/Response | Status | Plant/ Co. |
|---|---|---|---|---|
| | | plant is susceptible to large influxes of gracilaria when the salinity level in the river water is elevated. For example, gracilaria problems were correlated with high salinity levels in 2002, which led to high vulnerability conditions. In addition, during another influx of gracilaria, a downpower was required in August, 2001 to clean the 1A-South debris filter. In response to experience over the past 5 years with gracilaria and other intake canal debris, modifications are being implemented at the river water intake diversion structure, which is the first barrier for intake debris, to improve the debris removal capability.<br>In response to the influx of gracilaria, the plant implemented compensatory actions for a "High Vulnerability" condition in the intake canal. These actions include manning the diversion structure round-the-clock for manual debris removal, increasing screen wash pressure, and staging fire hoses at the traveling screens, if needed, to assist in removing debris. During the June 23 event, all four waterboxes on Unit 1 and three of four waterboxes on Unit 2 were managed within normal operating levels.<br>The power change was proceduralized. The plant operating procedure for circulating water directs a power reduction to isolate a waterbox and clean the debris filter if an abnormally high differential pressure exists after debris filter flushing has been completed.<br>The influx of gracilaria was not predictable greater than 72 hours in advance. Although the biology staff has found that high salinity levels in the river water make the conditions for a gracilaria release favorable, it is not possible to predict when an excessive influx will occur. The compensatory actions taken for a high vulnerability condition have usually been effective in preventing debris filter clogging.<br>Should this event be counted as an unplanned power change? | | |
| | | Response:<br>No, the event should not be counted as an unplanned power change. The increased accumulation of gracilaria in the river water was anticipated due to operating experience with high salinity levels in the river water, but the timing of the gracilaria release into the intake canal could not be predicted with certainty. In addition, the response to the condenser level and temperature conditions is proceduralized. | | |
| 39.2 | EP03 | Question:<br>If a licensee makes a change in ANS testing methodology, when can that change be used in the ANS PI calculation? | 8/18 Introduced | NRC |
| | | Response:<br>The change may not be used in the ANS PI calculation until the beginning of the next quarter. This is consistent with NEI 99-02, pg 94, lines 12-13, that states: "Periodic tests are the regularly scheduled tests..." Thus, the regularly scheduled test methodology that was used at the beginning of the quarter is to be used throughout the quarter for input to the ANS PI data. This is necessary to ensure the consistency and validity of the quarterly ANS PI data. As a reminder, if the change in ANS test methodology is considered to be a significant change per FEMA requirements, the change is required to have FEMA approval prior to implementation. | | |
| | | | | |

Attachment 10

# MSPI Items for Discussion

1. Front Stop

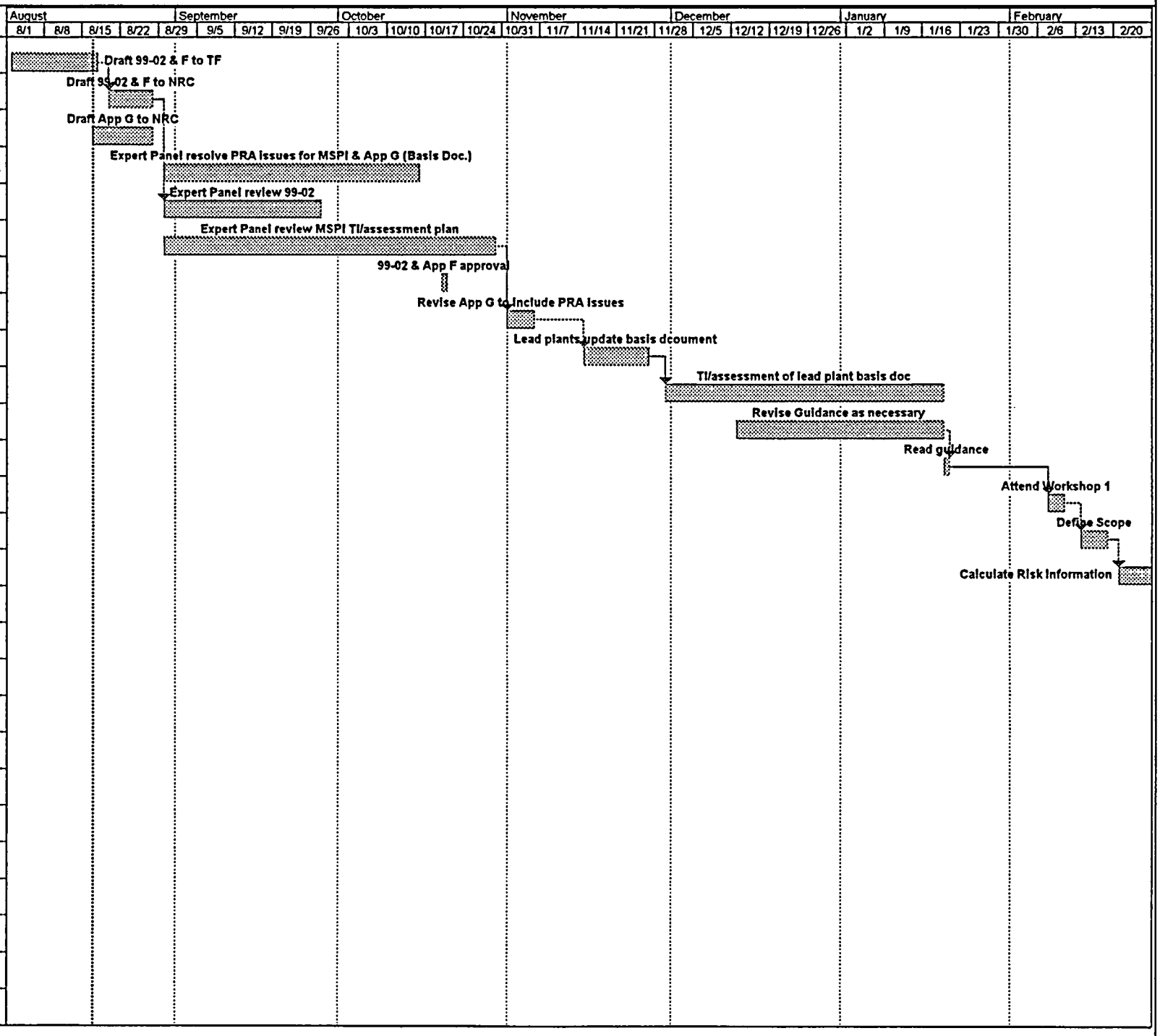
2. Short term Back Stop

3. MSPI PRA task force
   - establishing minimum
   - requirements/guidelines for MSPI
   - charter and staffing
   - scope and purpose

4. MSPI timeline discussion

# MSPI IMPLEMENTATION PLAN

| ID | Task Name |
|---|---|
| 1 | Draft 99-02 & F to TF |
| 2 | Draft 99-02 & F to NRC |
| 3 | Draft App G to NRC |
| 4 | Expert Panel resolve PRA issues for MSPI & App G (Basis Doc.) |
| 5 | Expert Panel review 99-02 |
| 6 | Expert Panel review MSPI TI/assessment plan |
| 7 | 99-02 & App F approval |
| 8 | Revise App G to include PRA issues |
| 9 | Lead plants update basis dcoument |
| 10 | TI/assessment of lead plant basis doc |
| 11 | Revise Guidance as necessary |
| 12 | Read guidance |
| 13 | Attend Workshop 1 |
| 14 | Define Scope |
| 15 | Calculate Risk Information |
| 16 | Create Basis Doc |
| 17 | Interface with NRC |
| 18 | Attend Worshop 2 |
| 19 | Revise Scope/Risk Info as needed |
| 20 | Calculate Historic Data |
| 21 | Revise basis document |
| 22 | Input data to ACCESS |
| 23 | Develop Administrative Controls |
| 24 | Support NRC Inspection of basis doc |
| 25 | Workshop 3 |
| 26 | Start MSPI implemenation |
| 27 | Report MSPI data |



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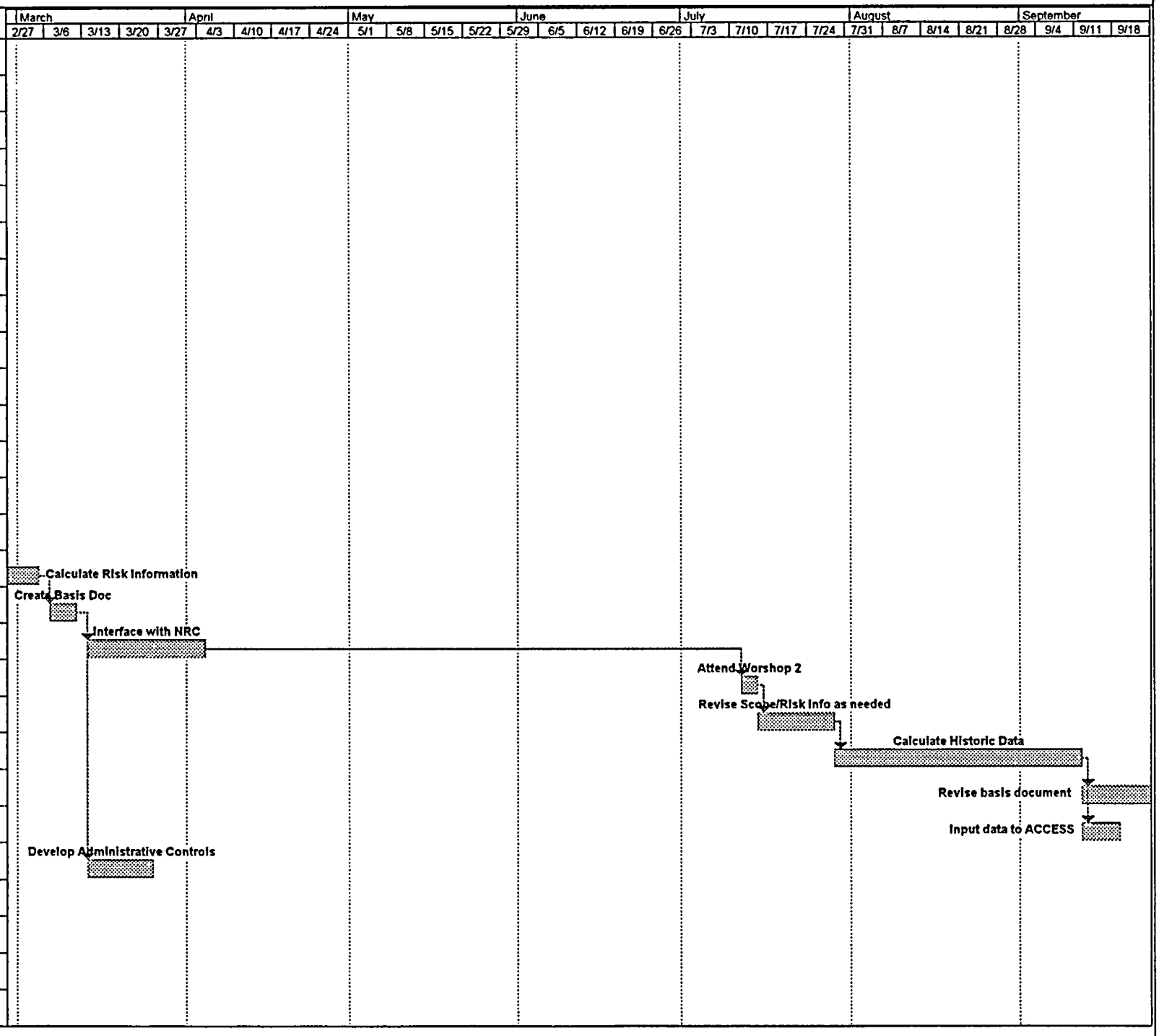

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