ROP Meeting Summary Highlights
May 22, 2002

Staff expressed interest in improving the initiating event cornerstone's scram and scram with loss of normal heat removal performance indicators. Industry stated that they have no plans at this time to consider an effort to pilot a scram PI replacement.

Industry raised three generic issues of concern involving an apparent inconsistency of ROP policy and the initial guidance of SECY 99-007. The first is that some SDPs, such as the public radiation protection SDP, aggregate occurrences into a higher level of significance. In general, industry opposes aggregation of lower level issues into higher significance findings. Industry was asking the staff to address this issue. This issue was placed on the agenda for the next meeting.

The second issue presented by industry was that the significance determination process (SDP) should not be used where any PI is providing the monitoring of performance for that equipment and if that equipment fails or is unavailable, and there are no other complicating factors involving that failure, then the PI should be adequate for the significance determination. While this has been an ongoing issue concerning the MSPI pilot program, industry broaden the issue to include all PI cornerstones.

The third issue industry raised was that a potential exists for a failure of a PI-monitored component to occur that would invoke a MD 8.3 event response evaluation, such that a risk assessment CCDP process (but not SDP) could color the failure, condition, or event at a higher level of significance that what the PI would characterize as its significance. Industry is concerned about the public's acceptance (and the staff's reaction) to the difference in outcomes from using the MD 8.3 process and the outcome of the PI. If such a situation occurs, then industry's position is that the staff should rely only on the PI outcome for input into the Action Matrix, and not from the risk assessment evaluation for purposes of licensee performance assessment.

Staff provided updates and an overview discussion on proposed improvements to the emergency preparedness ANS PI. The topic of interest was a staff proposal on how to modify the ANS PI's methodology on how to assess that ANS sirens are capable of performing their function, as measured by periodic siren testing in the previous 12 months. The proposal is to adopt some form of performance-based testing, rather than continue to use a reliability-oriented testing approach. Staff and industry continue to discuss proposed changes to the ANS PI.

A discussion occurred on progress made to date of industry's self-assessment program. Industry provided a draft procedure and plan of the processes and methods for conducting safety system functional assessment. The staff will review this document and provide feedback at the next public ROP meeting.

Progress was made on approving a number of frequently asked questions (FAQs), with considerable discussion on the Point Beach EDG KVAR coil failure FAQ 28.2. There was a developing consensus that the issue should be considered a discovered condition and thus evaluated and assessed using the inspection program and SDP. However, no change in FAQ review status was made (on hold).

Salem FAQs 29.9 and 29.10 concerning anticipated power changes greater than 20% in response to expected problems (i.e., abnormally high grass levels in the intake structure and traveling screens) was discussed, with the senior resident inspector and regional branch chief in attendance. The discussion revealed that additional information concerning these events was required and the FAQ should be rewritten.

Industry agreed to place on hold the Perry and LaSalle FAQs (FAQ 28.3, and 27.3) concerning scram with a LONHR. The group consensus was that a scram on a BWR high vessel level lockout of the TD FWPs was not a LONHR occurrence. However, a generic FAQ should be developed to generically address these two FAQs.

The Catawba and Oconee FAQs (29.6 and 26.12) were approved and changed to final status.

NEI COMMENTS ON LICENSEE SELF ASSESSMENT (LSA) IN THE REACTOR OVERSIGHT PROCESS

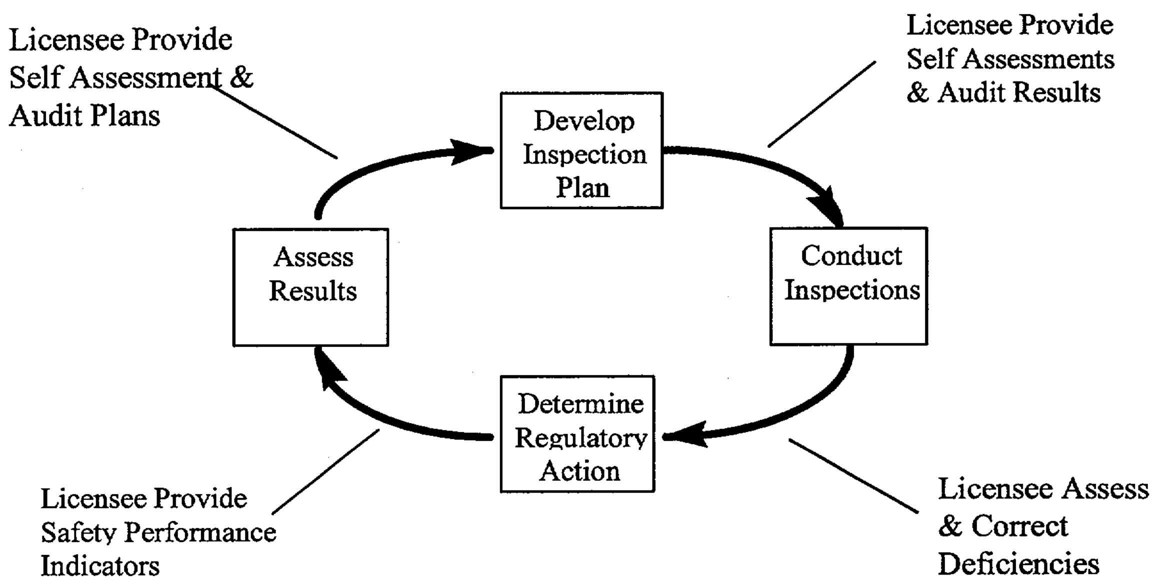
GOALS

- Maintain safety
- Maintain public confidence
- Reduce unnecessary regulatory burden
- More effectively utilize NRC/licensee resources while preserving NRC option to inspect

LSA IS NOT A NEW CONCEPT

- NRC Administrative Letter 94-03, "Announcing an NRC Inspection Procedure on Licensee Self-Assessment Programs for NRC Area-Of-Emphasis Inspections"
- Inspection Manual Chapter 40501, "Licensee Self-Assessments Related to Team Inspections"
- NEI White Paper "A New Regulatory Oversight Process" (9/10/98)

Regulatory Oversight Model



- Industry initiatives in self assessment:
  - CEOG SSFAs
  - Fire Protection (NEI 99-05)
    - Addresses FPFI
    - Piloted at two plants
    - Resource sensitive
- IIEP recommended "... consider whether to waive certain parts of the baseline team inspections and let licensees assess themselves under defined circumstances."

PROPOSED STRATEGY

- Develop roles and expectations for licensees and NRC in LSA
- Identify target areas to pilot and pilot volunteers
- Develop LSA guidance documents to pilot
- Develop NRC guidance on how to treat LSA in the Reactor Oversight Process
- Identify success criteria for pilot program
- Conduct multiple pilot programs
- Assess results and determine whether to proceed on industry-wide basis

WHAT ARE PROPOSED CRITERIA FOR PARTICIPATION?

- Voluntary initiative by one or more licensees (e.g., Owners Group initiative)
- Licensee has an effective corrective action and self-assessment program, as determined by being in the Licensee Response or Regulatory Response Column of the Action Matrix
- Licensee(s) docket formal request to conduct LSA
- NRC formally accepts docketed licensee self-assessment plan as being equivalent in scope and depth to NRC inspection – could involve an industry guideline, such as NEI 99-05 Fire Protection Self Assessment Guide

WHAT INSPECTIONS ARE GOOD CANDIDATES FOR PILOT PROGRAMS?

Top Candidates:

- IMC 71111.05, Fire Protection Triennial
- IMC 7111.21, Safety System Design and Performance Capability
- IMC 71121, Occupational Radiation Safety
- IMC 71152, Identification and Resolution of Problems

Second Tier Candidates:

- IMC 71111.02, Evaluation of Changes, Tests and Experiments
- IMC 71111.11, Licensed Operator Requalification
- IMC 71111.12, Maintenance Rule Implementation
- IMC 71111.17, Permanent Plant Modifications

WHAT ARE POTENTIAL POLICY, PROCESS, OR PROGRAM ISSUES?

- What objective criteria should the NRC use to determine if a licensee is eligible to participate?
- To what extent should the LSA include NRC inspection manual guidance be appropriate to ensure "consistent scope and depth"?
- Will industry self-assessment "standards" or guidance be needed to ensure "consistent scope and depth" with NRC IMC Chapter?
- What degree of "independence" (i.e., participants from outside the licensee's organization) is appropriate?
- What type and level of NRC oversight/participation/observation is appropriate?
- To what extent will licensee self-assessment reports be docketed or made public?
- How will results of self-assessments be treated under the ROP?
  - Subject to SDP?
  - Will the NRC issue Findings or Violations?
  - How will the results be treated in the Action Matrix?
  - Will violations of regulations identified by the licensee be subject to Enforcement?
  - How will "management" or "business" recommendations be handled?
- What are potential unintended consequences?
- How far in advance should licensees inform NRC of their intention to perform LSAs such that NRC can budget appropriately?

<table>
<tr><th>Temp No.</th><th>PI</th><th>Question/Response</th><th>Status</th><th>Plant/ Co.</th></tr>
<tr><td>29.9</td><td>IE03</td><td>NEI 99-02, Rev 2, states that anticipated power changes greater than 20% in response to expected problems (such as accumulation of marine debris and biological contaminants in certain seasons) which are proceduralized but cannot be predicted greater than 72 hours in advance may not need to be counted if they are not reactive to the sudden discovery of off-normal conditions. 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.

At Salem, this type of problem is caused by high river grass concentrations biofouling the heat exchanges, coolers, and condensers. Salem Generating Station has a number of methods to determine the possibility of high biofouling, in order to prevent an unplanned shutdown. These methods include regular sampling to determine river grass concentration, visual confirmation of excess river debris, an excessive Service Water Traveling Screen carryover, and high dP across heat exchangers and/or pumps. In the event of high river grass triggered by these methods, procedural instructions (SC.OP-AB.ZZ-0003(Q), Component Biofouling) are in place to initiate preventative actions to reduce biofouling. Over the past few months, the level of detritus has frequently risen above the Action Level I state, described in SC.OP-AB.ZZ-0003(Q), Component Biofouling, resulting in increased preventative actions. Unfortunately, high river grass concentrations and the biofouling of necessary equipment cannot be predicted.

On February 26, and again on February 28, Salem 1 reduced power to clean the 13A Condenser Water box due to the accumulation of marine debris and biological contaminants on the 13A Circulating Water Pump Traveling Screen. The 13B Circulating Water Pump had been out of service for maintenance in preparation for the upcoming grassing season. A downpower is procedurally required in situations like this when there are no operating Circulating Water Pumps (13A and 13B) in a Condenser Shell.

Concentrations this year began to increase in early October, decrease in early December, and increase again in mid-February. <u>In normal years, the high season was only spring, which was caused by ice thawing in the marshes</u>. That type of river grass is commonly local marsh grass. The type of river grass seen this year, sertularia argentea “Garland Hydroid” and garveia franciscana “Rope Grass”, are common to the Chesapeake Bay but have not previously been this abundant in the Delaware Bay. According to Dr. Dale Calder, author of <u>Hydroids and Hydromedusae of Southern Chesapeake Bay</u>, the type of hydroids the Delaware Bay is experiencing are common in high salinity water (ca. 13-30 o/oo) and is active from late September to early June. The observance of high salinity in the Delaware River this year may be attributed to the drought conditions observed over the past few months.

The following table indicates the river grass sample concentration, expressed in Kg/million cubic meters, for the time period in the question. The rapidly increasing levels contributed to the biofouling, which required the downpower.

2/13/2002 4,300
2/18/2002 328
2/21/2002 624
2/22/2002 488
2/24/2002 399
2/26/2002 1149
2/28/2002 1809
3/2/2002 2326
3/4/2002 5133

Do these two examples need to be reported as Unplanned Power Changes?</td><td>4/25/02
Introduced

Quantity of data preventable
no maint.</td><td>Salem</td></tr>
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Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response: No. These two examples represent power changes in response to expected accumulation of marine debris that cannot be predicted in advance. The response is proceduralized, and the operators followed their procedures. The environmental conditions cannot be predicted, but were appropriately monitored and the operator response was in accordance with expectations.		
29.10	IE 03	Question: NEI 99-02, Rev 2, states that anticipated power changes greater than 20% in response to expected problems (such as accumulation of marine debris and biological contaminants in certain seasons) which are proceduralized but cannot be predicted greater than 72 hours in advance may not need to be counted if they are not reactive to the sudden discovery of off-normal conditions. 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. NEI 99-02, Rev 2, does not discuss whether the power changes associated with these FAQs should be counted while awaiting disposition. Is it satisfactory to state in the comment field that a FAQ has been submitted, and not to include the power changes in the PI calculation? Response: Yes. The comment field should be annotated to state that a FAQ has been submitted. If the licensee believes that this exclusion applies, it is not necessary to include them in the PI calculation. The report can be amended, if required, at a later date.	4/25 Introduced	Salem
30.1	*EP02*	*Question:* *NEI 99-02 states in the clarifying notes for the ERO PI, "When the functions of key ERO members include classification, notification, or PAR development opportunities, the success rate of these opportunities must contribute to Drill/Exercise Performance (DEP) statistics for participation of those key ERO members to contribute to ERO Drill Participation." Must the key ERO members individually perform an opportunity of classification, notification, or PAR development in order to receive ERO Drill Participation credit?* *Response:* *No. The evaluation of the DEP opportunities is a crew evaluation for the entire Emergency Response Organization. Key ERO members may receive credit for the drill if their participation is a meaningful opportunity to gain proficiency in their assigned position.*	*5/22 Introduced*	

Temp No.	PI	Question/Response	Status	Plant/ Co.
30.2	*MS01*	*Appendix D Questions:* *NEI 99-02, Revision 1, in the Clarifying Notes for the Mitigating Systems Cornerstone, allows a licensee to not count planned unavailable hours under certain conditions when testing a monitored system.* *At our two-unit PWR station, three EDGs provide emergency AC power. There is one dedicated diesel for each unit and one swing diesel available for either unit. During the monthly surveillance testing required by Technical Specifications, there is an approximate four-hour period when the EDG is run for the operational portion of the test and is inoperable but available. In 2001, surveillance-testing procedures were revised to take credit for restoration actions that would enable not counting the hours as unavailable.* *The restoration actions for the two dedicated diesels during the approximate four-hour period consist of implementing a "contingency actions" attachment to the test procedure. This process verifies system alignment and places the EDG on its emergency bus. The steps allow the dedicated control room operator to change the emergency generator auto-exercise selector from exercise to auto, verify or place the emergency supply switch in auto, depress the emergency generator fast start reset button and adjust the engine speed and voltage as necessary. The process steps are, individually and collectively, simple and done by a dedicated operator. The last step requires the governor speed droop control to be adjusted to zero. However, the speed droop adjustment is not required for the EDG to satisfy its safety function. This step is performed to relieve the dedicated operator and does not challenge operation or control of the EDG.* *Question (1); can credit be taken during the restoration actions that require only one dedicated control room operator (no other assigned duties) resulting in not counting the unavailable hours during this portion of the testing of the dedicated EDGs? The restoration actions for the swing diesel also consist of implementing a "contingency actions" attachment to the test procedure with a few minor differences. Three additional steps determine which emergency bus the swing EDG needs to be aligned to before placing the swing EDG on that emergency bus. The rest of the actions are identical to the dedicated EDG explanation described above.* *Question (2); can credit be taken for these restoration actions that require only one dedicated control room operator (no other assigned duties) resulting in not counting the unavailable hours during this portion of the testing of the swing EDG?*	*5/22 Introduced*	*Surry*

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Licensee Response: *Yes, credit can be taken for restoration actions in both cases above and unavailable hours are not counted. Although NEI 99-02, revision 2, does not specifically apply to these questions, the exceptions to allow credit for operator compensatory actions with monitored systems, listed in Appendix D, are addressed to provide a rationale for the answer. (Item numbers below correspond to items in Appendix D.)* 1. *Not applicable.* 2. *High* 3. *A loss of off-site power is recognizable from alarms and installed instrumentation at the EDG control panel in the control room.* 4. *A dedicated operator is assigned during EDG testing who will conduct the compensatory actions if needed. All licensed operators were trained on the compensatory actions that are part of the operators continuing training. Operators in training were able to perform the contingencies and complete recovery actions within 3-5 minutes.* 5. *Communications is not applicable since an operator in the control room conducts the compensatory actions.* 6. *Compensatory equipment is normally installed station equipment.* 7. *Compensatory actions are specified ~~in an~~ attachment to the test procedure and are always available during the test.* 8. *All licensed operators were trained on the compensatory ~~actions that~~ are part of the operators continuing training. Compensatory actions are discussed as part of the pre-job brief each time testing is performed.* 9. *The probability of successful completion of compensatory actions is nearly one.* • *Action steps are simple, individually and collectively. Operators in training were able to perform the contingencies and complete recovery actions within 3-5 minutes.* • *A dedicated operator conducts the actions* • *No diagnosis or repair is required to complete the procedure* • *PRA calculations were conducted to determine the probability of successful completion of compensatory actions. For the dedicated EDGs, the probability of success is 99.75%. For the swing EDG, the probability of success is 99.5%.* • *The dedicated operator is easily able to maintain EDG frequency/voltage within required specifications by making manual adjustments during the time loads are sequenced onto the EDG. Once loads are sequenced on, adjustments would only be necessary when loads are removed per Emergency Operating Procedures.*		

Temp No.	PI	Question/Response	Status	Plant/ Co.
30.3	*EP01*	*Question:* *Should the follow up PAR change notifications be counted as four inaccurate notifications for the situation described below? On January 22, 2002, a drill was conducted which included opportunities for Classification, Notification and PARs. The initial Notification for the General Emergency and the associated PAR contained the accurate Time Event Declared of the classification. On follow up PAR change notifications (4), the Time Event Declared block was completed with the time of the PAR data instead of the time the GE was declared. The initial GE Event notification contained the proper time. The time was changed due to confusion of the Protective Measures Manager as to the meaning of this block. This was identified in the critique following the drill. There were four PAR changes made. The PAR, MET and other required information was accurate. Each PAR developed was accurate. The time the PAR was developed was accurate on the form.* *Once a General Emergency was accurately declared, and the INITIAL notification was made in a timely and accurate manner, changing of the time in the Time Event Declared block on the follow up notifications had no influence on the event initiation, nor did it result in untimely or inaccurate PARs being issued to the states and counties. The states and counties were provided the accurate information needed to take the appropriate actions for protection of the public. Changing of the time in follow up PAR change notifications did not impact their response since the states and counties were provided the accurate time of event declaration in the initial notification. No additional events were declared since the plant was already at the GE classification. This issue was critiqued and actions were taken to ensure the time desired for the Time Event Declared block on the form was communicated to those responsible for completing the form. Counting the four notifications inaccurate resulted in a decline of the DEP PI from 93.5% to 90.6% following the drill and to 92.6% for the first quarter 2002.* *Although the performance was not up to our expectations, considering the entire notification inaccurate on four separate occasions does not reflect the overall performance of the ERO team in the area of classification, notification and PARs. The team is fully capable of providing accurate classifications and PARs as well as timely and accurate notifications.* *Response:* *Since the INITIAL notification was made in a timely and accurate manner, changing of the time in the Time Event Declared block on the follow up notifications had no influence on the event initiation, nor did it impact the response of the states and counties. The states and counties were provided the accurate time of event declaration in the initial notification. Therefore, they can be counted as SUCCESSFUL as long as the other elements required for accuracy were correctly communicated to the states in a timely manner*	*5/22 Introduced*	*OPPD*
30.4	*MS01*	*Question:* *The St. Lucie Station programmatically maintains and manages risk associated with overhaul maintenance performed within Technical Specification Allowed Outage Times (AOTs). The program implements Regulatory Guide 1.177 and/or NUMARC 93-01 requirements for risk management during the maintenance activities. All work to be accomplished during a planned overhaul is scheduled in advance and includes maintenance activities that are required to improve equipment reliability and availability. St. Lucie considers overhaul maintenance as those overhaul activities associated with the major component as well as pre-planned corrective and preventive maintenance on critical subcomponents. For example, the EDG preventive maintenance program requires hydrostatic testing of the lube oil cooler every 12 years and the subsequent repair or replacement of the cooler as necessary. The purpose of the hydrostatic test is to pre-emptively reveal defects to preclude a run-time failure by applying far more pressure to the lube oil cooler than would be experienced during normal operation. This test was a scheduled item during a planned EDG overhaul, and the lube oil cooler did not pass the hydrostatic test. The lube oil cooler replacement was not included as a scheduled contingency item, nor was a replacement cooler on-site. However, replacement coolers of this type were known to be readily obtainable. The original overhaul duration was extended by the time needed for procurement and installation of a replacement lube oil cooler. Do the additional hours count as planned overhaul maintenance hours?*	*5/22 Introduced*	*St. Lucie*

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response: *As describe, the condition above is considered planned overhaul maintenance hours. In accordance with NEI 99-02, overhaul maintenance comprises those activities that are undertaken voluntarily and performed in accordance with an established preventive maintenance program to improve equipment reliability and availability. The EDG lube oil hydrostatic test meets this requirement.* *Additional guidance states that overhauls include disassembly and reassembly of major components and may include replacement of parts as necessary, cleaning, adjustment, and lubrication as necessary. NEI 99-02 provides a list of typical major components such as diesel engine or generator, pumps, pump motor or turbine driver, or heat exchangers. However, these guidelines do not preclude critical subcomponent planned maintenance, testing, or inspection activities from meeting the requirement for overhaul maintenance as long as these activities are preplanned and performed as part of the approved preventive maintenance program for the major component.* *The lube oil cooler hydrostatic test was a line item within the EDG overhaul schedule, and it was performed as directed by the preventive maintenance program. The failed hydrostatic test does not represent a new failure due to the anticipatory nature of the surveillance. Replacement of the lube oil cooler did not represent a major rebuild task, and the replacement part was readily available. Furthermore, planned overhaul maintenance does not mean that all contingency items for replacement parts need to be explicitly scheduled items during the overhaul. Therefore, the additional hours spent on lube oil cooler procurement and replacement are considered planned overhaul hours for the purposes of the safety system unavailability PI.*		
30.5	*MS01*	*Question:* *The overhaul of the EDG fuel priming pump was planned corrective maintenance and was scheduled as part of the overall overhaul activities for the EDG. Post maintenance testing revealed that parts installed in the fuel oil priming pump during the overhaul did not result in optimal performance. Although the pump operation would not have prevented the fuel oil priming pump from fulfilling its required safety function, the decision was made to rework the pump to recover pump performance. The rework resulted in extending the overhaul past its originally scheduled time. Does the maintenance rework count as planned overhaul maintenance?*	*5/22 Introduced*	*St. Lucie*
		Response: *As describe, the condition above is considered planned overhaul unavailability hours. The planned corrective maintenance for the EDG fuel oil priming pump was an activity undertaken voluntarily and performed in accordance with the established preventive maintenance program to improve equipment reliability and availability. NEI 99-02 states that additional time needed to repair equipment problems discovered during the planned overhaul count as non-overhaul hours only if the problem would have prevented the fulfillment of a safety function.* *The concern that was identified on the fuel oil priming pump during the post maintenance test would not have prevented the fulfillment of a safety function. Therefore, the additional hours spent on fuel priming pump rework are considered planned overhaul hours for the purposes of the safety system unavailability PI.*		

Temp No.	PI	Question/Response	Status	Plant/ Co.
30.6	*MS05*	*Question:* *Review of the Safety System Functional Failure Performance Indicator (PI) by the NRC Resident Inspector questioned whether Indian Point 2 LER 2000-006 should have been counted as a functional failure.* *Regardless of whether this LER constitutes a functional failure or not, there would be no PI threshold change.* *LER 2000-006 was submitted to the NRC on September 5, 2000. The LER is entitled "Source Range Detector High Flux Trip Circuitry Outside of Plant Design Basis Due To Revised Local Cabinet Temperature Uncertainty." This LER was coded as 10 CFR 50.73(a)(2)(ii). The LER determined the cause of the plant being outside the design basis was the temperature errors associated with the maximum control room design temperature were not explicitly accounted for when the setpoint was changed in 1973. There were no safety consequences associated with this LER since:* • *The IP-2 Tech Specs do NOT include any reactor trip set point limits for the NIS source range detectors,* • *The source range high flux trip is NOT credited in any UFSAR Chapter 14 accident analysis, and* • *The intermediate and power range flux trips would be available to provide for termination of a power excursion during a reactor startup or low power operation.* *The review of this LER did not determine this was a safety system functional failure since the source range high flux trip is not relied on in the UFSAR. Additional information:* • *NEI 99-02, Revision 1 refers to 10 CFR 50.73(a)(2)(v). It does state that paragraphs (a)(2)(i), (a)(2)(ii), and (a)(2)(vii) should also be reviewed for applicability for this PI (these were reviewed and the determination was only section (a)(2)(ii) was applicable),* • *NEI 99-02, Revision 1 also refers to NUREG-1022 for additional guidance that is applicable to reporting under 10 CFR 50.73(a)(2)(v),* • *NUREG-1022, Revision 2, section 3.2.7, at page 54 defines "safety function" as those four functions listed in the reporting criteria... as described or relied on in the UFSAR and* • *NUREG-1022 also adds at page 54 "or required by the regulations." Regulations are being interpreted to include technical specifications.* *Is it the intent of NEI 99-02 to solely report safety system functional failures as described or relied on in the UFSAR or is it the intent to additionally incorporate the guidance in NUREG-1022, section 3.2.7 that the failure of any component addressed in the plant's Technical Specification constitutes a safety system functional failure whether credited or not in the UFSAR chapter 14 analyses?*	*5/22 Introduced*	*IP 2*
		Response: *Since only SSCs credited in the UFSAR are intended or expected by the NRC PI program to meet the four reporting criteria (A)-(D) listed at page 67 of NEI 99-02 and page 52 of NUREG-1022, the phrase, 'or required by the regulations,' at page 54 of NUREG-1022 is an unintended application of NUREG-1022 to the NRC PI and should be disregarded for purposes of the NRC PI, safety system functional failures.*		

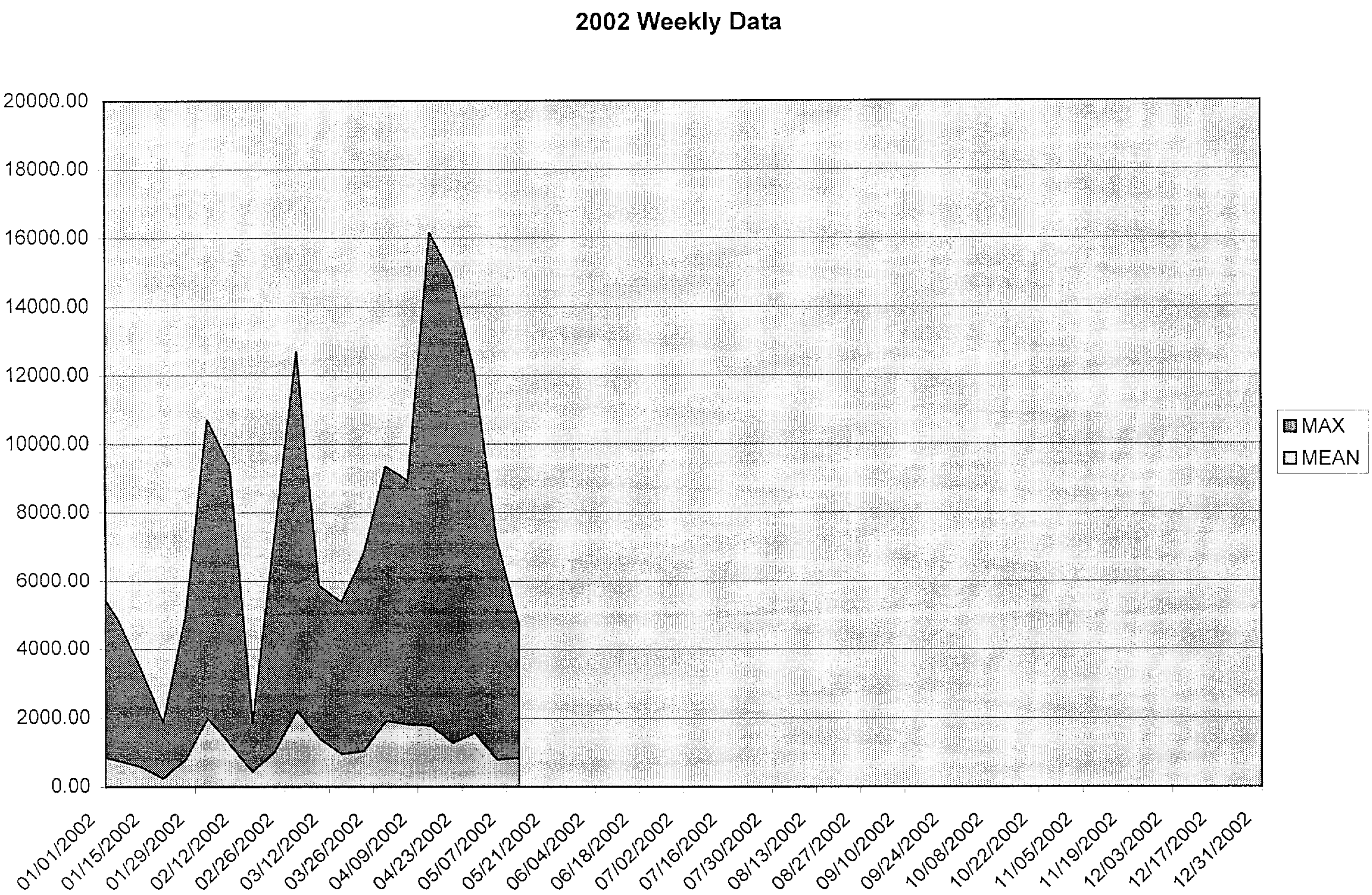
Temp No.	PI	Question/Response	Status	Plant/ Co.
30.7	*MS02 ,03,04*	*Question:* *As part of plant tour by an on-shift senior reactor operator, two covers were found to be missing for a piece of "guard" pipe used as a barrier over the main steam supply line to a Turbine Driven Auxiliary Feedwater pump. This "guard" pipe was designed to be used as a secondary barrier to prevent the spread of steam in the event of a steam supply line break to ensure environmental qualification of other plant equipment in the area. The covers provide access for inspection of the inner pipe and supports and are only needed for the postulated design basis rupture of that specific section of steam pipe.* *The deficiency was easily corrected by replacement of the covers. The time of occurrence looks to be associated with original plant construction and accordingly the deficiency has existed for a number of years.* *Engineering reviews are still being performed and the impact on equipment qualification is still indeterminate. However, if the environmental qualification cannot be confirmed this condition could result in three mitigating systems (AFW, RHR and SI) PI 's being red since the initiation of the revised ROP program. If handled as a standard equipment failure, fault exposure unavailability hours would be incurred for all/most of the hours from time of occurrence, functionally masking past and future performance until the fault exposure reset criteria is met and the hours reset.* *Can the fault exposure period for a construction/modification deficiency, as described above, that existed for a long period of time and that could not be identified by normal surveillance tests or inspection be addressed in the same fashion as a design deficiency hours described in NEI 99-02, Revision 2, Page 33, Lines 8 through 23?*	*5/22 Introduced*	*Watts Bar*
		Response: *Yes. While not specifically the result of a design deficiency, this construction caused equipment failure was not capable of being discovered during normal surveillance tests and has a long fault exposure periods thus meeting the same criteria as an excluded design deficiency. Its significance, like that of design deficiency, is more amenable to evaluation through the NRC's Significance Determination Process and thus should also be excluded from the unavailability indicators.*		
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?*	*5/22 Introduced*	*Generic*

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response: *For loss of all main feedwater due to high water level, or other design trips, the following guidance applies:* 1. *If all of the main feedwater pumps are not recoverable due to a problem in the feedwater system that requires repair actions, the condition is a scram with loss of normal heat removal.* 2. *If all main feedwater pumps are not available, and repair actions are required to restore at least one normal main feedwater pump, the condition is a scram with loss of normal heat removal.* 3. *If the main feedwater pumps are not needed but procedures call for the pumps to be started if needed and it is determined that at least one pump would have restored feedwater flow, the condition is NOT a scram with loss of normal heat removal.* 4. *If the main feedwater pumps are needed and no main feedwater pumps are able to restore flow, then the condition is a scram with loss of normal heat removal.* 5. *If the main feedwater pumps are needed and at least one main feedwater pump would have been able to restore flow, it is NOT a scram with loss of normal heat removal.* 6. *If the main feedwater pumps are secured following a scram in accordance with emergency operating procedures to reduce the steam load on the reactor, it is NOT a scram with loss of normal heat removal.* *For the conditions NOT to be a scram with loss of normal feedwater, at least one main feedwater pump must be capable of being recovered without the need for repair and all but minimal and rapid diagnosis. The main feedwater pumps must be able to be restarted from the control room with normal monitoring/startup actions by an auxiliary operator dispatched locally.*		

FAQ 28.3 *Additional Discussion*

The NRC has questioned our assessment of this situation with respect to the Loss of Normal Heat Removal Performance Indicator guidance. In particular, the Region/Senior Resident, in consultation with NRR, are taking the position that because the operators may have believed that the MFP was unavailable (even though it was fully capable of fulfilling its function), it must be considered unavailable for this indicator. To support this position, the NRC points to operator statements indicating a failure/loss of the MFP, and sending operators into the field to check the status of the equipment (diagnosis). Also, the NRC maintains the 15-20 minutes when the MFP was in this state further substantiates their position that recovery of the pump was not simple. The NRC has submitted a feedback form to NRR to obtain clarification of the intent of the indicator regarding availability.

As indicated in the discussion above, reactor vessel water level had been raised back to Level 8 by injection from the HPCS and RCIC systems, precluding restart of the feedwater pumps (including the MFP) (due to being at Level 8). The annunciators for MFP Trip or Fail to Start had not been illuminated. During this period when the MFP could not be started due to the high level condition, the control room dispatched in-field operators to the MFP, where no abnormalities were found with the pump or breaker. Four minutes later, a log entry recorded that the pump was ready for start. The MFP was started 14 minutes later (30 minutes after the scram), in accordance with SOI-N27, Feedwater System, Section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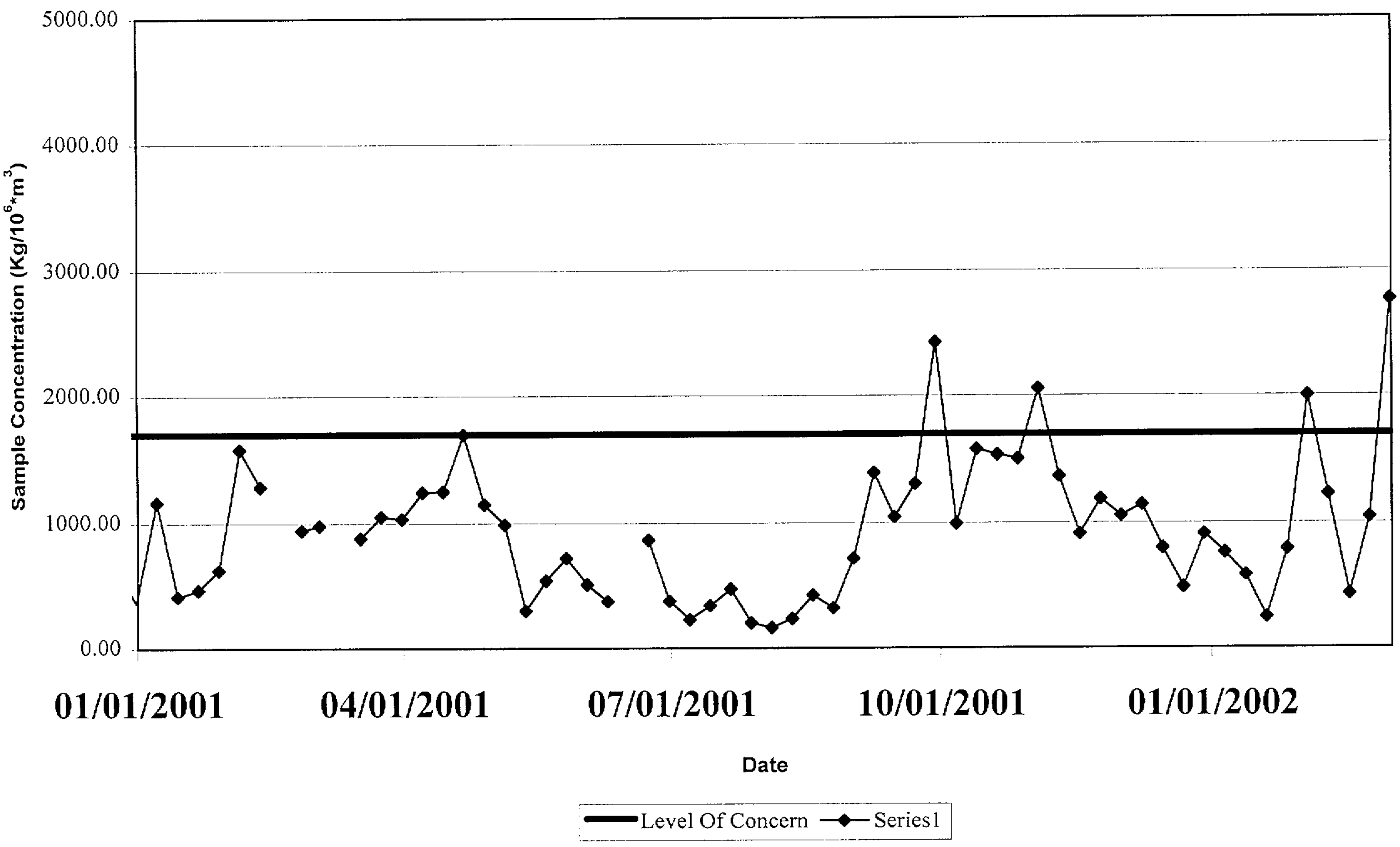
08/27/2002
09/10/2002
09/24/2002
10/08/2002
10/22/2002
11/05/2002
11/19/2002
12/03/2002
12/17/2002
12/31/2002
MAX
MEAN

Salem CWIS Impingement Weekly Detritus Loads
December 1999 - December 2001



2000 Weekly Data