The following questions and requests for additional information were transmitted by the ACRS to the NRC in an 11/10/08 letter with the subject "TRANSMITTAL OF ACRS MEMBERS' CONCERNS REGARDING CONTAINMENT OVERPRESSURE (COP) CREDIT FOR THE BROWNS FERRY EXTENDED POWER UPRATE"

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1) Staff Review of the Alternative Fire Hazard Analysis NPSH Calculation

The July 9, 2008, draft COP SER submittal to the ACRS stated that, "The NRR staff briefly examined the information TVA provided; however, the information provided did not result in a revision to the previous staff's basis regarding credit for containment overpressure." The following questions address the staff's review of the TVA fire hazard analyses.

a) The November 2007 Round 13 RAI response presents the fire hazard analysis screening criteria. Did the staff review the fire hazard screening criteria and find the criteria reasonable? Will the alternative fire analysis and the associated COP analysis presented to the Committee be reviewed, approved and incorporated into the safety evaluation report?

To be answered by NRC technical staff

b) Has the staff reviewed the alternative sensitivity analyses supporting the LOCA, SBO and ATWS COP to determine if the key assumptions, input parameters and equipment performance used in the deterministic analyses are reasonable?

To be answered by NRC technical staff

2) Clarification of the Alternate Analysis July 10, 2008, Presentation

(RAI APLA-35/37 of the November 15, 2007, RAI responses - Round 6)

a) Specify the balance of plant equipment assumed to be available during the scenario. Are there any limitations to the equipment availability for the duration of the event that would affect the mitigating systems?

Response - OK

For the two limiting cases which require COP (fire areas 4 and 9 as identified in TVA's November 10, 2008 submittal), three trains of Balance-of-Plant (BOP) equipment are readily available to maintain reactor water level. The BOP equipment includes the main condenser hotwell, which is the makeup water inventory source, one (of three available) condensate pumps, one (of three available condensate booster pumps), the startup feedwater bypass valve, along with their associated controls and power supplies. Maintenance of condenser vacuum is not required. One condensate storage tank (of three on site) would be available to provide longer term water inventory makeup to the hotwell.

This BOP equipment is aligned to provide water to the reactor during power operation and would continue to do so in the alternate analysis. Availability of the equipment *depends on offsite power. Additionally, the reactor must be depressurized for the BOP to pump to the vessel.*

b) Describe how the systems and equipment (RHR & BOP) will be aligned to support the core and suppression pool cooling.

<u>*Response - OK*</u>

The BOP equipment would remain in its normal alignment to pump water from the hotwell to the reactor to maintain reactor vessel inventory. The Residual Heat Removal (RHR) system would be aligned in the suppression pool cooling mode of operation, which is a standard mode of RHR operation.

Are these alignments included in the plant procedures for this event? What ensures that the appropriate personnel remain trained and qualified for this mode of operation?

<u>*Response- OK*</u>

Yes. In the alternate analysis described in TVA's June 12, 2008 , submittal, the controlling procedures are the plant Emergency Operating Instructions (EOI's). The EOI's either contain specific alignments or specify the use of other operating instructions which do so. Use of EOIs is an integral part of the initial and continuing training program for plant operations personnel. The EOI modes of operation utilized in the alternate analysis are the same as those that would be used for any event that involved a complete loss of high pressure make-up capability and do not represent an unusual or complex use of EOIs.

c) For the alternate fire analysis presented to the ACRS, was a reactor core cooling analysis performed or were the reactor core conditions evaluated without reanalysis?

<u>*Response - OK*</u>

As discussed in TVA's June 12, 2008, submittal (Response to ACRS Issues), in the alternate analysis, high pressure injection systems are not available for fire areas 4 and 9. Therefore, the reactor must be manually depressurized via safety/relief valve (SR) actuations to allow low pressure systems and BOP to inject which restores and maintains reactor water level at normal level. The rapid reduction in reactor pressure is conducted in accordance with the plant EOIs and is referred to as emergency depressurization in the syntax of the symptom-based EOIs. The BFN EOI procedures are based on BWROG EPG/SAG Appendix C and supporting technical analyses, which ensure that peak clad temperature does not exceed 1500 F during the emergency depressurization operation.

d) For the fire hazard analyses, would any fire requiring COP result in a LOOP? Since BOP systems depend on off site power, could a fire in areas 04 and/or 09 cause LOOP?

<u>*Response - OK*</u>

In TVA's November 15, 2007, submittal, only two fire areas (4 and 9) were identified that required COP. In these two fire areas, the supporting analysis determined that offsite power would be available (i.e., *no mechanistic means existed in either area for a fire to cause a LOOP).*

e) Identify any key parameters, inputs, and assumptions in the analysis that differ from the licensing calculations. Compare the values and assumptions used and justify the differences.

<u>Response</u>

Table 2 Changes in Inputs and Parameters for Limiting Fire Areas NPSH Basis Analysis

Parameter	Licensing Basis Value	Relaxed Analysis Value	Basis for change
4. initial suppression pool volume	122,940 cubic feet (minimum TS level)	123,855 cubic feet	Based on>95% confidence from historical data
7. initial drywell pressure	15.5 psia	15.9 psia	Increased to match assumptions in original GE tasks reports for Appendix R.
15. RHR heat exchanger K value	227 BTU/sec-°F	241 BTU/sec-°F	Based on realistic fouling factor of 0.0020 vs 0.0025 and maximum number of tubes plugged (1.5%). This is more representative of RHR heat exchangers.
17. RHR Mode of Operation	9400 gpm in LPCI mode until RPV depressurization, then 6000 gpm in Alternate Shutdown Cooling	7,000 gpm	In the alternate analysis, RHR is in suppression pool cooling mode. For the containment cooling analysis, the low end (7000 gpm) of the EOI operating restrictions is used. For calculating NPSHa, the high end is (9000 gpm) is used.
18. drywell coolers in service	10 for first 2 hours, then coolers isolated	drywell coolers on throughout the event	Conservative scenario assumption
22. RHR pump heat addition	2,000 horsepower	1,600 horsepower	Corresponds to above 7000 gpm flow rate
23. RHR pump required NPSH	Time-stepped value (minimum 21 feet, maximum 30 feet)	17 feet continuous	Corresponds to 3% NPSHr curves provided by Sulzer.

f) On Page E-4, TVA states that they have identified minor changes to procedures that will be made in order to improve the response to the fire event. What are these minor procedural changes? Would these procedural changes affect the Appendix R safe shutdown instruction (SSI) or the Units' EOPs?

Response - OK

Below is a mark-up of the changes being made to the BFN fire protection report and the SSI instruction entry conditions. The addition is shown in red:

The entry conditions for an Appendix R event are as follows:

1. *Unit 1, Unit 2, or Unit 3 reactor is greater than atmospheric pressure, AND*
2. *The magnitude of the fire has the potential to affect safe shutdown capability as indicated by:*
   - *Multiple failures/spurious actuations of systems/components have occurred, OR*
   - *Erratic or questionable indications on numerous MCR instruments have occurred, OR*
   - *Multiple trains/channels of safety related equipment are threatened by the fire.*

AND

3. *Reactor water level cannot be restored and maintained above +2" narrow range via operation of available equipment*

The additional reactor water level related condition retains the ability to enter the SSI's in a time frame consistent with the supporting calculations, while recognizing the possible availability of other significant mitigating equipment that is not utilized within the SSI's. This revision ensures that in the design basis event the SSI's will be reliably entered, while also avoiding a premature, procedurally-directed abandonment of equipment that would be of high value to the operators in mitigating a fire event. This change enhances the plant's ability to achieve and maintain safe shutdown in the event of a fire.

g) The following questions relate to the Appendix R analyses:

i) Is LOOP assumed for this event? If so, are the drywell coolers available for the first two hours of the event as assumed in the Appendix R analysis?

Response - OK

In the Appendix R event, Loss of Offsite Power (LOOP) is assumed at time zero of the scenario. For the Appendix R licensing NPSH analysis, the drywell coolers are assumed to be inservice for the first two hours. However, in several fire areas, fire damage would cause the loss of some drywell coolers or the pumps that provide cooling water to the drywell coolers. Therefore, the two-hour assumption for drywell cooler operation is conservative in some fire areas.

ii) Provide discussions on how the staff confirms that the operator actions specified in the procedures and the operator trainings are consistent with the mitigation actions assumed in the analyses. For example, explain how the drywell coolers (within 2 hours of the start of the event) would be implemented in the SSI, EOP or other procedures.

Response

In this case, the licensee made a formal regulatory commitment to modify SSIs to secure drywell cooling within two hours of an Appendix R event. The licensee determined that tripping the RBCCW pumps that supply cooling water to drywell coolers or by closing RBCCW valves in the drywell cooling loop was the best way to accomplish this (either of these actions renders the coolers inoperable). In revising the SSIs, the licensee's Fire Protection Program verification and validation (V&V) process ensures that the physical action is feasible and can be accomplished within the time limit. Each SSI was subsequently modified to include steps that require RBCCW cooling water be secured within 2 hours. In Spring 2007, NRC inspection staff reviewed a sample of the SSIs and the V&V packages as part of the Browns Ferry Unit 1 restart inspection program for fire protection. Additionally, SSI adequacy is audited in the scheduled NRC fire protection program inspections.

iii) For the different fire scenarios, are there any conditions that could result in the drywell coolers not being turned off or being restarted after being initially turned off? If this is feasible, explain the specifics (e.g., operator actions) of each fire scenario that would be implemented in procedures.

Response - OK

Drywell coolers are normally in service and will continue to operate during reactor shutdowns. In the event of a LOOP, there is load shed logic that would trip drywell coolers and RBCCW pumps immediately following the LOOP for a brief period of time (~ 40 seconds) and then automatically restart the same components.

In the SSIs, drywell cooling is terminated by tripping the RBCCW pumps that supply cooling water to the drywell coolers or by closing RBCCW valves in the drywell cooling loop. Once these SSI steps are completed, it would take manual operator action to put the coolers back in service. This would not be permitted until the emergency was over and plant management authorized exit from the SSIs.

3) Pump Performance Data

In determining the required NPSH for given flow conditions, the pump vendor establishes required minimum NPSH values that correspond to operation at some degree of cavitation corresponding to 1% or 3% head loss.

a) For Browns Ferry RHR and CS pumps, explain if the 3% head loss was always used in determining the required NPSH or was the 1% criteria initially used for the Browns Ferry pump performance evaluation.

Response

A 3% head degradation was the original criteria for the determination of NPSHr for the Browns Ferry RHR and CS pump sales curves. Contractually, however, the scope of *testing was only required to demonstrate 3% or less head degradation when the pump was suppressed to the NPSH sales curve values.*

In previous NPSH calculations (prior to EPU) and for the original EPU NPSH calculations, the NPSH analyses used NPSHr values that were based on the Browns Ferry pump sales curves with conservatism added. The values chosen well below the 1% head loss curves shown in Curves 2 and Curve 4, but still were still above the 3% values Curves 2 and Curve 4 except at very high flow rates. In the August 31, 2006, submittal, TVA employed stepped NPSHr values based on 8000 hours of operational life as shown in Curve 3 for both the LOCA and Appendix R analysis, which reduces the NPSHr compared to the original EPU calculations. In the June 12, 2008, submittal, in the alternate analysis, TVA uses the 3% NPSHr values from Curve 2 (Core Spray is not used in Appendix R). Use of the 3% curves provides a reduction of several feet in NPSHr and lessens considerably the magnitude and duration of required COP. At present, TVA is redoing the Appendix R licensing basis calculations using the 3% curves, which also reduce the magnitude and duration of required COP. The LOCA calculations continue to use the stepped curves from Curve 3. However, as discussed in 3.h, the short-term LOCA calculations are being redone at 11,000 gpm and 100% RH, which will show improvements in required COP.

b) The SULZER report states that the original test records were lost or misplaced. During the briefing, it was stated that the raw data for the required NPSH are available. These statements appear to be conflicting. Please, clarify.

<u>Response</u>

The Sulzer report is referring to original BFN test reports. Copies of the witnessed reports were available and used in the development of the NPSH curves.

c) For the ST-LOCA, the vendor states that the scenario falls outside the established operating recommendations for the RHR pumps. However, based on some test data, the vendor concludes that although vibrations and noise may occur due to surges and cavitation, the pumps should be able to continue to function. In these tests, the suction pressures were varied so that the pumps would cavitate. At what temperature were these tests conducted? Would the test results be different if the suction temperature of the flow is also increased in order to make the test more prototypic?

<u>Response</u>

NPSHr reduces with increasing water temperature as shown in ANS standard, ANSI/H1-1.5-1994, Centrifugal Pumps, published by the Hydraulic institute. Therefore, determination of NPSHr at lower temperatures is conservative.

d) For the Appendix R scenarios, the vendor states that: "The minimum required NPSH value that will allow the subject pumps to successfully operate at 9000 gpm for 70 hours is 17 feet. At this NPSHa, level there is little to no theoretical NPSH margin remaining. The RHR pump, subject to these conditions will likely exhibit signs of cavitation; however it will continue to function throughout the event." Similar to the assessment for the STLOCA, were the tests conducted at prototypic temperatures?

Response

The original BFN pumps tests were conducted at approximately 100 F°. NPSHr reduces with increasing water temperature as shown in ANS standard, ANSI/H1-1.5-1994, Centrifugal Pumps, published by the Hydraulic institute. Therefore, determination of required NPSH at lower temperatures is conservative.

e) In the SULZER report, the vendor combines empirical data and calculations to develop the NPSHr curves for different pumps and flow rate. In essence, the operability of the pumps and the flow rates for both Appendix R and the ST-LOCA rely on the accuracy of the SULZER tests. In addition, the generated NPSHr do not include or quantify uncertainties, which may affect the calculated margins in all events. Have these uncertainties been quantified? What are the uncertainties in the NPSHr values at different flow rates?

Response

Each of the TVA RHR pumps underwent an NPSH test at the factory. Operation was demonstrated at NPSH values at, or below, the sales curve NPSH values with 3%, or less head degradation. The 1% and 3% head loss curves shown on Curves 2 and 4 were generated from the same model pump. The data from this test is shown on Page 21 of the Sulzer report.

The referenced testing was compliance with ASME power test code 8.2, and Hydraulic Institute; gages and other instruments were calibrated in accordance with these governing specifications. Uncertainty is an industry standard since the specifications dictate the kinds of instruments to be used.

f) Data from all the pumps manufactured by the vendor that are similar to the RHR and core spray pumps used in Browns Ferry have been averaged to develop average characteristic curves for the pumps. In both the Appendix R and the more realistic fire scenario only one RHR pump will be in service. The characteristic curve of this pump could be different from the average behavior of all pumps. Considering the 1.6 psi margin for Appendix R calculations, the accuracy of the characteristic curves becomes important. Are the uncertainties in the characteristic curves small enough to assure that there actually is margin for the Appendix R scenario?

Response

Each pump was supplied with its own characteristic curve which is documentation of the contractual witness test. The report includes a characteristic averaged head/flow curve (Curve 1), which was derived from TVA's RHR pumps only; no other test data was included in the average. Curve 1 is are used to TVA to establish the operating characteristics of the pumps for determination of NPSHa. The performance curves compare well and averaging is a satisfactory approach for this application. One witnessed performance curve (customer curve 27872) for a Browns Ferry RHR pump was included in the report as an example.

The 1.6 psi margin presented in TVA's submittal for Appendix R Licensing basis is the result of using the NPSHr values derived from the 8000 hour stepped curve. In a limited time duration event application such as Appendix R, use of a 3% head loss curves *provides several feet of NPSHr improvement. Therefore, small differences in individual pump performance characteristics is not important*

g) The cavitation free required NPSH is 75.3 ft for flow of 12,000 gpm. The SULZER recommended required NPSH for 12,000 GPM, for 40,000 hours is 99.8 ft. Explain the discrepancies between the lower cavitation free NPSH and the recommended NPSH, which does not preclude cavitation. There is a similar discrepancy for the core spray pumps at 4500 gpm.

Response

The "cavitation free" NPSHr calculation is from the Lobanoff & Ross pump design book and is a theoretical curve (not based on test results.) It uses a prediction of head degradation as the basis for its analysis and the calculations are presented in the report.

The Sulzer recommended NPSH is an analysis that is based on head loss and bubble formation with the realization that bubble formation (cavitation) occurs before head degradation is even measurable. This effect increases as flows diverge from BEP and the Sulzer recommended curve will eventually cross the Lobanoff & Ross pump design at high flows. BEP is 8600 gpm for the RHR pumps and 3000 gpm . The Sulzer recommended NPSH curves are based on long term pump operation (40,000 hour service intervals).

During plant operation, RHR pumps are in service for extended periods of time only when the plant is in shutdown cooling and are operated at flow rates typical of BEP. In shutdown cooling, there is approximately 100 feet of elevation head available, so NPSHr for extended pump operation are easily satisfied. Core Spray pumps are only operated for very short periods of time to satisfy surveillance testing. Accordingly, operation of RHR and Core Spray pumps at very high flow rates is of interest only in short-term accident analysis calculations, which are of limited time duration (10 minutes).

h) The draft staff SER justifies the operation of the RHR pumps for a short-duration <LOCA> under degraded conditions, in part, based on sensitivity analyses that showed with lower LPCI flows (11,000 gpm) and drywell humidity (50%), the margin increases. Explain the reasons for the difference between the maximum LPCI flow used in the NPSH calculations (11,000 gpm) for the ST-LOCA and the manufacturers design runout flow 11,500 gpm)

Response

The current short-term LOCA analysis (injection into the recirculation loop discharge side – pipe break loop) uses a flow value of 11,500 gpm, which is approximately the manufacturer's pump runout flow. In the field, the LPCI flow is restricted by the injection flow path. TVA calculations show that the actual flow will be 11,000 gpm. A lesser flow rate reduces NPSHr.

TVA is redoing the short-term LOCA calculations at 11,000 gpm and at 50% humidity. The 8000 hour stepped curve NPSHr curves will be used.

4) Inhibiting Automatic Actuation of Containment Coolers

For Browns Ferry Appendix R, the drywell coolers are assumed to be turned off after 2 hours into the event in order to maximize the containment pressure. Without turning off the drywell coolers, the required NPSH for the sole RHR pump would exceed the available NPSH for a significant amount of time. The drywell coolers are considered non-safety systems but are relied upon in meeting the TS containment pressure and temperature. These TS containment P/T values are assumed as initial conditions in the containment analyses. The following questions relate to the turning automatic systems off.

a) Operator actions requiring turning off automatic systems under high temperature and pressure containment environment are counter-intuitive in terms of containment integrity. Justify why counter-intuitive operator actions under a high PT conditions are acceptable, in the context of industry lessons- learned experience. In addition, provide evaluation of the NRC lessons-learned assessment and actions in reference to inhibiting automatic although non-safety containment pressure reduction features that would then result in an increase in containment pressure. The issue is not whether the specific Appendix R scenario would threaten containment integrity but rather implementing operator actions that would counter the overall containment integrity objective of reducing the pressure.

<u>*Response - OK*</u>

As discussed in item 2.g.iii above, in the event of a LOOP, there is load shed logic that would briefly trip and restart the drywell coolers and RBCCW pumps immediately following a LOOP. Aside from this indirect automatic operation, drywell coolers are put into service and removed from service by operators action and have no automatic functions.

Drywell coolers are normally in service and will continue to operate during reactor shutdowns. This is also true for Appendix R shutdowns provided the fire did not damage the subject components (e.g., RBCCW pumps/electrical boards that power the RBCCW pumps or drywell coolers). So in most fire area, the drywell coolers would continue to operate. For the purpose of ensuring sufficient COP was available during Appendix R scenarios, the SSIs were revised to require that the RBCCW pumps that supply cooling water to the drywell coolers be tripped or the RBCCW valves in the drywell cooling loop be closed. In the execution of SSIs, strict procedural compliance is required of the operators.

5) Impact of High Temperature Environment on Pumps and Penetration Seals

a) For Appendix R, demonstrate that the high P/T environment would not adversely affect the systems and components required to mitigate the event, such as SRV tailpipes and neutron monitoring systems.

<u>*Response - OK*</u>

For the Appendix R case, the maximum drywell temperature is 201 F and maximum drywell pressure is approximately 10 psig. Equipment qualification requirements are bound by LOCA scenarios, which are considerably higher.

b) Evaluate the impact of prolonged exposure to high pressure/temperatures and radiation field on the seals and penetrations. For any adverse impact, evaluate how it affects the availability of containment overpressure and the operability of the equipment relied upon to mitigate the event such as pumps.

Response - OK

For the Appendix R case, the maximum drywell temperature is 201 F and maximum drywell pressure is approximately 10 psig. Equipment qualification requirements, including radiation, are bound by LOCA scenarios, which are considerably higher.

Miscellaneous NRC Technical Reviewer (Lobel) Questions. TVA has not yet reviewed.

1. (Pg 3 of 37) What is basis for averaging the certified witness test performance curves to produce an average performance for each pump type? What is the range of data between the curves for the individual pumps? Why is averaging acceptable?

Averaging was used to provide a single head-capacity curve to use as a discussion point in the report; NPSH discussions and calculations refer to flow at BEP. Since the range of BEP locations of the averaged curves is much smaller than the variance allowed by various test standards (up to 10%), it is appropriate to use the average curve as a basis for discussion. Sulzer does not suggest that there is any use for the averaged curve except as described in this paragraph.

2. (pg 3 of 37) How are the TVA supplied values of the minimum NPSH used in the study? Is any other info from TVA used in the study (temp, press, etc.)?

TVA data was used to establish that a gap exists between the new operating scenarios and the contractual NPSH data certified when the pumps were originally supplied. The Sulzer report was generated to address the problem that this gap represents.

3. (pg 3 of 37) How are the time durations in table 1 considered? For example TVA App R time is 60 hrs (likewise for the other times in the table); how is the 60 hrs used by Sulzer? Accident calcs show that containment accident pressure is needed for 60 hrs but the pump is required to operate after that time. TVA supplied 60 hrs for APP R but the TVA calc shows that COP is need for 71 hours – how is the fact that it needs to operate after that time considered. Is the difference between 60 and 71 hrs significant?

All test results, NPSH predications and operation recommendations were based on an analysis of actual pump data and are independent from any/all TVA data. The report states the capabilities of the pumps in addition to the originally installed documentation.

4. (pg 5 of 37) The suction specific speed of the RHR pump and the CS pump indicate that they are high suction energy or very high suction energy pumps; how is this factored into determining the values in table 3 and curve 3?

Suction energy is useful in determining system NPSH margin during the design phase. Its significance in Sulzer's report is the conservatism of curve 3 that has been described above.

5. (pg 6 of 37) Table 2 RHR cavitation free NPSH shows a value of 75.3 ft at 12000 gpm. Table 3 RHR recommended NPSH gives a value of 99.8 ft at 12000 gpm, curve 3 on pg 10-37 shows the required NPSH at 12000 gpm is much less than either 75.3 or 99.8 ft. What is the diff between table 3 recommended value and the curve 3 required NPSH value? (Table 3 value is for 40000 hrs and the curve 3 hours are for 8000 hrs both resulting in the same amount of damage/erosion?). What are the table 3 RHR recommended NPSH values used for? Why is the table 3 recommended NPSHr (12000 gpm / 40000 hrs) greater that the cavitation free value (see curve 2)? Wouldn't being equal be acceptable? Other than for information how was the cavitation free curve used?

The Labanoff "cavitation free" NPSH curve was provided and used for information only. Please see response to ACRS question 3g.

6. (pg 10 of 37) Describe the development of the curve 3 curves. How is the value of NPSHr and the time at that value determined? Is there significance to the slopes of the lines between the horizontal portions of the curves?

As stated above these curves are recommendations based on the allowed duration of damage causing cavitation. They are based on the NPSH characteristics of the pumps and include subjective data by experienced Sulzer Engineers. Again, as stated above, these values can be seen to be conservative: these pumps can operate for long periods of time at the 3% curve and indefinitely at the 1% curve – by 100 hours curve 3 recommendations are all close (slightly above except low flow) to the 1% curve.

7. (pg 10 of 37) How is the interpolation/extrapolation between the different flow rates done in curve 3?

Data/curves for pump performances are always presented at discreet flows (NPSH curves), speeds (VFD H-Q curves), trim diameters , etc. Unless customer operation falls at exactly one of the discreet values interpolation/extrapolation is performed in the customary fashion.

8. (pg 8 of 37) It is stated that the 40,000 hrs value is based on limited cavitation damage, also the 1 % and 3% curves in curve 2 demonstrate slight cavitation damage. What is the difference?

Cavitation begins long before there is any measurable head loss (despite head loss being the specified industry standard); when there is cavitation there is potential for cavitation damage. The various NPSH analysis techniques are an attempt to generally quantify the damage rate.

9. (pg 9 of 37) Explain the phrase "adequately removing enough energy form the pump to prevent catastrophic failure". Does this include seals, bearings shafts and other pump parts or just the impeller erosion?

Energy removal is strictly a discussion about impeller erosion.

10. (pg 19 of 37) The transient NPSH study states that the curves are based on a new pump in Sulzer's judgment; what would be the changes as the pump ages considering that it is subject to in-service testing? Is there a difference between the RHR pumps which are used frequently and the core spray pumps which are not?

Service testing should not cause degrading wear. Sulzer was informed that the RHR pumps have seen little use. Furthermore, during routine use, the pumps have excess NPSHa.

11. What is the uncertainty in the curve 3 curves? What is the uncertainty in the 1% and 3% curves?

Curve 3 provides a scheme for 8000 hours (~1 year) of operational life, while providing for potential cavitation events that are beyond the contractual scope of these pumps when purchased.

Curve 3 is based on the 1% and 3% NPSH curves as well as the Sulzer "recommended" calculation (for 40,000 hr life at BEP). Uncertainty of the 1% and 3% curves have been addressed in Sulzer's previous ACRS question response. An "uncertainty analysis" is not appropriate to curve 3 because of the subjective empirical data that it contains as well as its high degree of conservatism: "damaging cavitation" is subjective and relies on the experience of Sulzer's Engineers. The "recommended" curves provide 40,000 hour with very little damage; we've limited this (in curve 3) to 8000 hrs and allow damage. The 3% curve is what Sulzer typically uses to develop its sales NPSH curves (in general this allows operation at these NPSH values); except for the first 15 hours of the 11,500 gpm line all of the recommendations of curve 3 are above the 3% curve giving us another layer of conservatism.