

Bill,

for your review.

Richard

ATTACHMENT A

PORC 05-13 Meeting Notes
Oyster Creek License Renewal Application

Presenter: T. Quintenz

50.59 Safety Evaluation Yes No

Disposition:

- Approval Recommended
- Approval Recommended with Conditions (see below)
- Remanded
- Review Only

Issue Summary:

AmerGen is developing a License Renewal Application (LRA) for Oyster Creek Generating Station. The LRA consists of an integrated plant assessment and environmental report prepared in accordance with 10CFR54. The application will demonstrate that the effects of aging on certain plant equipment and structures will be adequately managed during the period of extended operation in a manner, which preserves the current licensing basis. The review responsibilities of the PORC members are detailed in the Charter (Attachment B).

Safety Impact:

There is no impact on nuclear safety. There is no change or proposed change to the current licensing basis or the Technical Specifications. In accordance with 10CFR54, the LRA is primarily a detailed engineering assessment with proposed programs and future commitments to manage aging.

Questions / Comments by PORC:

Questions and comments from PORC members are presented in Attachment C. Two of the items on this attachment were considered sufficiently significant to be documented as CAPs: (1) no fatigue analysis for the feedwater expansion bellows at the drywell interface (CAP O2005-2246), and (2) adequacy of the monitoring / trending of Torus corrosion (CAP O2005-2249).

ATTACHMENT C

Oyster Creek License Renewal Application Questions / Comments from PORC Members

1. I have not found any discussion of the unit 2 discharge tunnel. I don't know how the north end was closed off but if by stop logs they could deteriorate during life extension and create a large sink hole just north of the circulating water intake tunnel that would potentially jeopardize the intake structure and safety related power to the intake.
2. I have not found a TLAA or aging management discussion for the Torus. From a nuclear safety perspective, the Torus needs to be treated in the LRA as robustly as we have treated the drywell on page 3.5-20 for aging management. The internal underwater coating is blistered so corrosion prevention for the period of license extension is jeopardized. And the Torus was built with no corrosion allowance so I believe has the least margin of any part of the containment.
3. On page 3.5-27 we discuss a finite element evaluation of the concrete near top of drywell that is degraded due to elevated temperatures. Did this analysis account for the lateral drywell loads that I believe are transmitted to this concrete structure during a seismic event?
4. On page 3.5-44 we discount as not applicable the aging management of sliding supports and yet the drywell has sliding supports to compensate for thermal growth and transmit seismic loads. Are we sure aging management of the drywell sliding supports is not required?
5. On page 4-26 a table of reactor design transients is presented. I do not have nuclear safety issues but in reading the table a number of questions come to my mind. Only 5 more turbine trips for the life of Oyster Creek? No more operational cycles of shutdown cooling loops A and B for the life of OC? Emergency Condenser design analyzed operational cycles were "not specified" but text says 5,000 were analyzed? And there are places in text where cycles are discussed using numbers somewhat different than the table (aka lack of consistency) which could raise questions. My sense from reading the text is we have lots of operational cycle margin so I would not underestimate cycles on this table and I would strive to make table consistent with the text to minimize questions.
6. On page 4-51 in 4.7.2 we refer to reference 4.21 but it has been renumbered 4.8.21.
7. On page 4-51 paragraph 4.7.3 we discuss corrosion of rebar in the equipment pool and reactor cavity walls and project 9%-12% reduction for extended life of Oyster Creek. I believe from a nuclear safety perspective the controlling structure with least margin is the floor of the fuel pool. The floor was supposed to be attached to the walls with a rebar configuration that was "L" shaped to anchor it to the walls. This is not the configuration we found and is why we had to limit the fuel pool temperature to 125F to ensure the floor did not detach and drop during a seismic event and rupture the fuel pool liner. If this rebar is really corroding as projected I suspect our design analysis of the floor support is not valid today let alone for a 20 year life extension. My recollection is that the analysis relies on friction between the imbedded rebar and concrete to maintain the structural integrity and with corrosion I believe the friction would be greatly reduced. I am not aware of any evidence that the rebar in the region of the fuel pool floor connection is corroding but with 4.7.3 on the record we need to deal with this issue.
8. On page 4-50 we refer to the sand bed as "inaccessible" and yet we were in there to recoat and periodically go back in to inspect coating. I believe this is a holdover of description from before we removed the sand.
9. On page 3.5-23 we describe a rate of corrosion of 04. mils per year vice what I believe is intended of 0.4 mils per year.

10. On page B-4 we refer to condition report and the proper term for New CAP is Issue Report (IR).
11. Page B-28 claims water chemistry has been effective in protecting instrument penetrations and SLC penetrations from IGSCC. Yet elsewhere in LRA there was a statement that water chemistry is not counted on for protection of stagnant systems like these. Is this consistent and more importantly is water chemistry really protecting these penetrations? Or are they just not susceptible? Water chemistry early in the life of OC was not very good and I suspect with all of the IGSCC we have seen elsewhere in our systems it would have occurred here too if the location was susceptible.
12. On page B-31 I think the words "will be inspected" are missing from the enhancements description for top guide.
13. On page B-32 we say no new crack indications have been found in core spray piping welds and yet we had an IGSCC core spray pipe leak from IGSCC just external to reactor vessel two outages ago. I realize this discussion is for core spray piping internal to the vessel but are we sure it is true that water chemistry is protecting this stagnant system?
14. On page B-32 we take credit for the current reactor coolant water chemistry effectively mitigating crack growth in the top guide but I thought that the chemistry protection provided by hydrogen injection was not effective in protecting this structure. I would be worried about the future when we find new cracks or more crack growth in the top guide being used to call into question our water chemistry program if we incorrectly take credit for water chemistry protecting this structure here. If noble chemistry is the chemistry additive that now protects this structure then Ok, but we did not inject that until 2002 so it sure was not what was controlling the crack growth before then.
15. Page B-42 under operating experience, I believe the "No" at beginning of second sentence should be deleted.
16. B.1.12 lists a number of bolted connections that are not managed by the bolting program but are managed by other aging management programs. Are these other programs requirements consistent or comparable with NUREG 1801? If so then say so. If not, don't we need to list and justify the different requirements contained in the other programs?
17. B.1.13, the ESW and SW piping under the deck at the intake is in a particularly aggressive environment, has required piping replacement and failed the external coating early. Piping in this environment is not discussed and I believe requires unique aging management if we are going to run for 20 more years.
18. B.1.20 operating experience "is operated for during testing" I suspect the word for should be deleted, or else there is a time duration missing.
19. B.1.20 operating experience. I would reach a different conclusion. Recent operating experience is showing that the fire water system above and below ground piping is reaching end of life due to corrosion and a more aggressive aging management program than wait until the leaks find us is needed. Now, if the two leaks described had some unique and location specific reasons we better explain in order to justify our wait and hope approach to dealing with leaks in the systems.
20. 4.7.2 and 3.5-23, the TLAA and aging management for drywell do not discuss the potential for aggravating the corrosion rate if the environment in the inaccessible areas is allowed to get more moisture. Drains buried in the reactor building concrete structure are indicated as being in scope for spatial interaction but in my opinion should also be in scope to ensure they do not create a leak path for water to the annulus area between drywell and concrete structure. Initially in the first stages of this problem we tested these drain paths to ensure leak tightness and actually found some that had to be plugged associated with the skimmers. Also, the trough at the top should be managed for degradation. It is concrete, subject to high temperatures to degrade it's strength and has already deteriorated and cracked allowing water to get to annulus region vice being directed away.

21. B.1.34 – Limiting the inspection of cables in this environment to visual only does not seem adequate. Representative cable samples will need to be tested by a qualified lab to ensure the cables are retaining their insulation, tensile strength and any other properties necessary in order to satisfy design basis considerations. And we routinely are replacing these types of cables so getting samples over next few years is relatively easy and inexpensive.
22. B.1.36 – Probably useful to define medium voltage, I think it is 4160V and not 480V.
23. B.2.1 – Do the test procedures ensure that the compressed air flow is sufficient in terms of velocity to dislodge piping corrosion products that normal system flow with water will dislodge? If not, I am not sure we can take much credit for them proving that plugging from corrosion products will not occur.
24. Table 4.2.2-1 What changes to plant ops are related to the values in the table (use staged PT curves). Do we need to change the NSSS leak test procedure, do we need to change the minimum temperature at which the vessel head can be tensioned?
25. Limits for cold overpressure requires a relief request to cover extended operation time frame. The PHC did not review this issue. Please develop a listing of existing relief requests that must be resubmitted prior to entering extended operations and present it to the PHC for concurrence and budgeting.
26. Table 4.3.1-1 some of the values of analyzed cycles are less than the projected cycles for extended operation. (example is vessel heat-up's and cool-down's 240 analyzed, 272 projected to occur) Is this an impact to the LRA, what does the station do if we get close to or exceed a limit?
27. 4.3.3.1 Reactor coolant pressure boundary was designed to B31.1 1955 edition, the code did not require fatigue analysis and thermal cycle monitoring was done. The technology exists to perform fatigue analysis, what is the regulatory risk of not doing so?
28. 4.3.3.2 says Nine Mile Pt 1 Iso Condenser design is bounding for OC's configuration. I recall that while Nine Mile does have Iso Condensers, they have multiple units (4 or 6) and OC only has 2. Please confirm that the analysis still applies.
29. Table 4.6.2-1 Does not reflect the feedwater penetration bellows. Why not?
30. 4.7.1.2 Did the analysis on the turbine building crane include the "engineered Lifts" that are performed to support Generator overhaul activities?
31. **Action Required:** Suggest STC discuss the need for training related to License Renewal Application (LRA) at next meeting.
Recommendation: In discussing the structural monitoring program and the new cable visual inspection program at the PORC review of LRA it became obvious that there is knowledge and skill training needed to ensure our personnel are prepared for the NRC inspections of our aging management programs this Fall. I believe the LRA project manager can present his assessment of training needs and plans the LRA team has to deliver some of it. And STC can assess adequacy of these plans and determine what groups are involved. The training is needed to prepare for the Fall NRC site LRA related visits to ensure we are successful in defending our aging management programs. Initial thoughts from two items discussed in PORC are as follows:
 - Cable visual inspection. This is a new aging management program that requires identification of locations where cables are subject to harsh environments (primarily constant elevated temperature I think) and then documented visual inspections of condition of the external insulation in order to assess cable condition. The training is associated with what to look for. There may even be tools involved since some magnification may be needed to find the cracking indicative of a degradation problem requiring further evaluation. Not sure who would do inspections but feels like position specific continuing training for a small group of experts.

- Structural Monitoring. What we currently do is apparently (at least in opinion of LRA project manager) not adequate to meet the expectations the NRC LRA onsite review team will have. We need knowledge training to raise the expectation bar for those who monitor our structures and passive components. Those who roam the plant on a daily basis like security and operations could benefit by the knowledge of what to look for. The more critical eyes the better in terms of adequately monitoring our plant for age related degradation that is important to license renewal.

32. System Scope questions are marked in the attached table.

Table 2.2-1 lists the Oyster Creek systems, structures and commodity groups that were evaluated to determine if they were within the scope of license renewal, using the methodology described in Section 2.1. A reference to the section of the application that contains the scoping and screening results is provided for each in-scope system and structure in the Table.

Table 2.2-1 Plant Level Scoping Results

System, Structure or Commodity Group	In Scope?	Comments
Reactor Vessel, Internals, and Reactor Coolant System		
Control Rods (2.3.1.1)	Yes	
Fuel Assemblies (2.3.1.2)	Yes	
Isolation Condenser System (2.3.1.3)	Yes	
Nuclear Boiler Instrumentation (2.3.1.4)	Yes	
Reactor Head Cooling System (2.3.1.5)	Yes	
Reactor Internals (2.3.1.6)	Yes	
Reactor Pressure Vessel (2.3.1.7)	Yes	
Reactor Recirculation System (2.3.1.8)	Yes	