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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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SUBCOMMITTEE ON THE PLANT LICENSE RENEWAL

APPLICATION OF COOPER NUCLEAR STATION

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WEDNESDAY, MAY 5, 2010

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ROCKVILLE, MARYLAND

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The Subcommittee convened at the Nuclear Regulatory Commission, Two White Flint North, Room T2B1, 11545 Rockville Pike, at 8:30 a.m., Mr. John Stetkar, Chairman, presiding.

SUBCOMMITTEE MEMBERS PRESENT:

JOHN W. STETKAR, Chairman

SAID ABDEL-KHALIK

J. SAM ARMIJO

MARIO V. BONACA

HAROLD B. RAY

WILLIAM J. SHACK

JOHN D. SIEBER

CONSULTANT TO THE SUBCOMMITTEE PRESENT:

JOHN J. BARTON

NRC STAFF PRESENT:

KATHY D. WEAVER, Cognizant Staff Engineer and Designated Federal Official

BRIAN HOLIAN

BO PHAM

GREG PICK

TAM TRAN

CLIFF DOUTT

STAN GARDOCKI

DAVE ALLEY

ABDUL SHEIK

ON YEE

ALSO PRESENT:

BRIAN O'GRADY

ART ZAREMBA

DAN BUMAN

DAVE BREMER

TODD HOTTOVY

ALAN COX

PHIL LINNEAR

BOB BOWDEN

ROGER RUCKER

KEN THOMAS

ROMAN ESTRADA

JOSH PULLMAN

JOHN CABELLA

BRIAN SQUIRP

MARSHALL VANWICK

REZA AHRABLI

C-O-N-T-E-N-T-S

P-R-O-C-E-E-D-I-N-G-S

(8:28 a.m.)

OPENING REMARKS

CHAIR STETKAR: The meeting will now come to order.

This is a meeting of the Plant License Renewal Subcommittee. I'm John Stetkar, chairman of the subcommittee meeting.

ACRS members in attendance at Jack Sieber, Harold Ray, Sam Armijo, Said Abdel-Khalik, Bill Shack and Mario Bonaca.

Our ACRS consultant, John Barton, is all present.

Kathy Weaver of the ACRS staff is the designated federal official for this meeting.

The subcommittee will review - it's too early in the morning (laughter) - the subcommittee will review the license renewal application for the Cooper Nuclear Station and the associated draft safety evaluation report with open items.

We will hear presentations from the NRC staff, Nebraska Public Power District representatives, and other interested persons regarding this matter.

We have received not written comments or requests for time to make oral statements from members

of the public regarding to today's meeting. The entire meeting will be open to public attendance.

The subcommittee will gather information, analyze relevant issues and fact, and formulate proposed positions and actions as appropriate for deliberation by the full committee. The rules for participation in today's meeting have been announced as part of the notice of this meeting previously published in the Federal Register.

A transcript of this meeting is being kept and will be made available as stated in the Federal Register notice.

Therefore we request that participants in this meeting use the microphones located throughout the meeting room when addressing the subcommittee. The participants should first identify themselves and speak with sufficient clarity and volume so that they may be readily heard. We will now proceed with the meeting, and I call upon Brian Holian to begin. Brian.

STAFF INTRODUCTION

MR. HOLIAN: Good morning. My name is Brian Holian. I'm the division director for the Division of License Renewal in NRR. I just have some brief opening comments and introductions, and then

I'll turn it over to the applicant, Nebraska Public Power, for their presentation, which will be followed by the staff presentation.

Just brief introductions of NRC staff. To my left is Bo Pham who is the Branch Chief responsible for this and several other plants. Interestingly Bo will also be here next month when Duane Arnold comes before the subcommittee. And I mention that also because one of the open items that we face today that will be covered by both the applicant and the staff is the torus-coating issue, and you haven't - I think - is it this week or next week, ACRS will receive the Duane Arnold SER. And it has a similar issue with their torus coating also. I believe the staff has just recently closed it out, but it's a similar type condition issue and coating issue. So I just bring that up, because you will see two of those plants come. And the staff will address that more during our presentation.

Behind me from Region IV we have Neil O'Keefe, the branch chief in the Division of Reactor Safety, and Greg Pick, the senior reactor inspector from Region IV. So you will be hearing from them later.

I just wanted to note that Sam Li, the

deputy of license renewal, is not here today. I just wanted to mention he is over in Vienna on his second trip helping out with the International GALL. The U.S. is helping out quite a bit with the International GALL. And if the ACRS wasn't familiar with that we could give you an update on that some time. But towards the end of the year they are looking to finalize that with many countries participating in that effort.

I mention that also because just April 30th, so just last week, NRR, Division of License Renewal, issued for public comment the 10-year update to the GALL. So you will hear probably a little bit about that today. It is up for public comment. We have some workshops within NEI and the industry in the next several weeks, two to three day workshops, and we'll be receiving their comments.

You're probably hear a little bit about the new GALL update on one of the open items today, which is buried piping. We have tried to improve the GALL position on the types of inspections and how to do that in the new GALL, and that is one of the open items we are covering, not only for Cooper today but for all the plants that are in house with us, 12 to 13 applications in house requests for additional

information and further study on that issue.

With that I'd like to turn it over to Brian O'Grady. He'll be coming up to the microphone and introducing applicant staff. He is the chief nuclear officer for Nebraska Public Power. Thank you.

NEBRASKA PUBLIC POWER DISTRICT - COOPER NUCLEAR STATION

MR. O'GRADY: Good morning. We appreciate this opportunity to present to you today our application and answer questions about our plant, our programs.

I'm Brian O'Grady, the chief nuclear officer for Nebraska Public Power District. I have with me our chief executive officer, Ron Asche. I just want to say that we fully support the long term safe operation of Cooper Station, and hopefully we will leave you with the impression that we have not only met the requirements but in many cases have gone beyond the requirements.

So with that I'll turn it to Art Zaremba, our nuclear safety assurance director.

BACKGROUND

MR. ZAREMBA: Thank you, Brian, and good morning. As Brian said we appreciate the opportunity to be here today. Thank the committee members. I'm

the director of nuclear safety assurance at Cooper Station. Before we get started with today's agenda I'd ask our presenters at the front table to introduce themselves.

MR. BUMAN: My name is Dan Buman. I'm the director of engineerings. I've been with NPPD for approximately 23 years.

MR. BREMER: Dave Bremer, the project manager for license renewal. I've been with NPPD now for 29 years.

MR. HOTTOVY: Todd Hottovy, engineering support manager at Cooper. I'm responsible for the programs and component engineering staff. And I've been with NPPD for 25 years.

MR. ZAREMBA: We also have Roman Estrada, our design engineering manager. Roman is off to the side and will speak to the torus-coating issue later on in the presentation today. And we have a number of other technical staff and project support personnel that are with us today to be able to address any questions that you may have.

Our agenda today briefly will take us through - we will spend a short amount of time on the early topics today, the background of Cooper and some of our operating history and experience; talk a little

bit about our scoping for our license renewal application and the application of GALL, and the tracking of commitments that we have associated with our operation going forward.

We will spend the majority of our time today and try to very quickly to get to the technical items of interest so that we can have a good discussion on those open items.

The background at Cooper, Cooper is a General Electric 400 watt or four Mark 1 containment reactor. GE supplied the nuclear steam supply system, and Burns & Roe was our original architect engineer for the balance of plant construction. Our licensed power output is 2,419 megawatt thermal and approximately 830 megawatt electric from the Westinghouse turbine generator at the station.

We use the Missouri River for our source of cooling water. Just to give you an idea physically where the plant is located, we're in the southeast corner of the state of Nebraska, about an hour north of us is the city of Omaha. Approximately two hours or so down to the southeast is Kansas City. So those are the major areas of population around the site.

Today's plant status: at Cooper Station we have been online safely continuously operating

producing electricity for 173 days. And the unit is at 100 percent power today. We have no threats to electrical generation, no equipment challenges at this point today at the site.

Our next scheduled refueling outage will be March of next year, 2011.

Just briefly you can see there is some of the plant history, Construction Permit was issued for the station back in June of 1968, and we began commercial operation on January 18th, 1974. Excuse me, our operating license was issued January 18, 1974, for commercial operating in July of 1974.

You see we have adopted improved tech specs at the site. We have finished an Appendix K power uprate, and we have an operating license expiration date of January 18, 2014. Which is why we are here today.

CONSULTANT BARTON: Your refueling cycles are how often?

MR. ZAREMBA: Every 18 months, yes, sir.

CHAIR STETKAR: Did you just recently announced you are going to go to a 24-month?

MR. ZAREMBA: We have a project to go to a 24-month cycle, that is correct. Board approval occurred just recently.

MEMBER SIEBER: Do you plan any future power uprates?

MR. ZAREMBA: We do have a project that is being worked. We have not gone to the board for funding yet. We plan to do that later this year with an implementation timeframe of 2016.

MEMBER SIEBER: And what magnitude of power uprate do you have in mind?

MR. ZAREMBA: Up to 20 percent increase over original power.

With that, I'd like to turn the first presentation over to Dan Buman, our director of engineering.

MR. BUMAN: Thank you, Art.

NPPD has been making significant investments to ready CNS for operation beyond 40 years. This slide lists some of the more significant upgrades already completed to maintain the facility. Rather than discussing all of them I'd like to focus on a couple of key replacements that we have completed.

Service Water Pipe Replacement: based on our input from our erosion/corrosion program in place at CNS. A concern was identified with microbiological influenced corrosion, or MIC, in service water piping

in the reactor building. As a result piping was replaced as well as the dead legs.

CONSULTANT BARTON: Is that service water piping lined or unlined, coated or uncoated?

MR. BUMAN: The service water piping itself has a coating on both the inside and on the exterior side for all the underground piping.

MEMBER SHACK: And the replacement material is?

MR. BUMAN: The replacement material is also carbon steel. So we are back in continuous monitoring with that.

CHAIR STETKAR: And when was that done?

MR. BUMAN: The piping replacement was completed in roughly about the 2000 timeframe.

MEMBER SIEBER: And that is the underground part?

MR. BUMAN: This was inside the reactor building part. We have completed pull-throughs on the service water piping itself on the underground portion, done some examinations, also some additional scans.

MEMBER SHACK: And you said the underground is both coated and lined, interior and exterior?

MR. BUMAN: That is correct.

MEMBER SHACK: And you are using biocides for the MIC?

MR. BUMAN: We currently are not using biocides for the MIC. We had identified several dead legs basically where had fostered some of the growth. This was somewhat localized within our reactor building at that particular time frame. And so we cut those out and removed those dead legs also to eliminate those breeding places for the MIC.

As Art mentioned we are situated on the Missouri River, and that is a challenging environment of silt, sand and sediment. As a result of system performance monitoring several key upgrades in the intake structure have been completed to meet this challenge and add operational margin. Specifically turning veins were added into the channel and the rear wall profile was modified to minimize the amount of sediment intrusion into the intake structure.

Trash racks and trash rakes were improved design and traveling water screens have been replaced with new dual flow design providing better filtration by eliminating any sort of carry over.

And finally sonar technology has been added to monitor the condition of the bay and the

emergency service water system.

MEMBER SHACK: With the suction strainer replacement how much of your insulation was replaced or what kind of insulation do you still have left?

MR. BUMAN: The majority of our insulation is mirrored insulation. I would need to - I don't have the numbers of how much of the regular has been left. It was our intent to go in there and to eliminate the majority of that. But the new suction trainers we have out at the margin, and we do have that factored into calculation, I just don't have that with me right now.

MEMBER SHACK: You do have a significant amount of fibrous insulation left?

MR. BUMAN: I would say no, we do not have a significant amount of fibrous insulation left.

CHAIR STETKAR: And on the intake structure, I notice that you had screened out the trash rakes, and I guess there is I'll call it a dam in the intake structure, you screened those out from license renewal. I was curious why. It would seem that failures of the trash - the bar rakes or whatever you guys call them out there could cause problems if indeed they corrode over the life of the facility and either collapse - and the collapse can either trap

material or it can allow more material to get into the traveling screens and plug those. So I'm a little curious if someone could speak to that.

MR. ZAREMBA: Alan, maybe as part of our scoping and lead on that, could you --

MR. COX: This is Alan Cox with the license renewal team. I think the reason for that is that the trash racks and grates that you are talking about are primarily there for the circulating water, and with the lower flow rates associated with the service water, a failure of those bar grates are not going to affect the central service water supply to the plant. That is the reason for the exclusion of the trash racks. They are just there basically for power production purposes. The design of the intake is set up where those failures will not impact the service water.

CHAIR STETKAR: Plugging perhaps, but if they - if they collapse for some reason, it allows a lot of stuff to come in.

MR. BUMAN: The trash rack and trash rakes and the profiles are basically there to just remove the big pieces. The traveling screens are dual flow design, there is no carry over through that. The screens for our emergency service water system are

3/16th holes basically that allow the filtration to go through, and would prevent that from being plugged.

CHAIR STETKAR: Thank you.

MR. BUMAN: In addition eight feedwater heaters have been replaced based on the oil thinning and tube plugging identified by the flow accelerated corrosion program and eddy current detecting.

MEMBER SHACK: And those materials were?

MR. BUMAN: Steel. The feedwater heaters.

MEMBER SHACK: And what is the new material?

MR. BUMAN: Phil?

MR. LAYER: This is Phil Layer for the applicant. And the old heaters were carbon steel material, the new heaters are chrome molly material. We change material for flow accelerating corrosion concerns.

MR. BUMAN: Additionally several control system such as the reactor feedwater pumps, speed control, reactor vessel level control, main turbine pressure control, and main generator voltage regulator, have been upgraded with new digital technology resulting in operating systems with increased redundancy to minimize future operational

challenges as well as addressing key equipment obsolescence.

While many utilities perform this type of upgrade, CNS used operating experience from their upgrades to incorporate the lessons learned and implement development upgrades without incident to add the additional operational margin.

MEMBER SIEBER: In your main unit condenser, what's the tube material there? Is that replacement material or original?

MR. BUMAN: The tube material inside the condenser itself?

MEMBER SIEBER: Yes.

MR. BUMAN: Ken or Phil.

MR. LINER: This is Phil Liner for the applicant. We changed the material. It was brass to begin with and that's been changed to a stainless steel material.

MEMBER SIEBER: Has the original material caused detrimental chemical effects in the reactor core system?

MR. LINER: No, it has not.

MEMBER SIEBER: It's got copper, you know.

MR. LINER: It was replaced early on in

the life of the plant.

MR. ZAREMBA: And we haven't seen - I think the question is more historically while it was in place did it cause any issues.

MEMBER SIEBER: Right, and there would be a residual even today. It declines over time.

MR. ZAREMBA: We have our chemistry manager here actually, but we've not seen any effects from any of the condensers. Bob, do you want to provide some details?

MR. BOWDEN: Bob Bowden speaking on behalf of the applicant. We periodically monitor reactor water, condensate water, for specific metals, cations, anions, that could be indicative of a river water leak. And we have no significant leaks in our condenser. We do periodic testing at the end of outages to identify any potential leaking tubes. And we plug those tubes.

MEMBER ARMIJO: Do you have deep beds or filter demineralizers for your clean up system?

PARTICIPANT: Bob Bialky (Phonetic) speaking for the applicant. We have filter demineralizers.

MR. ARMIJO: Okay. I wanted to ask you a question about your containment piping replacement.

What is - what piping did you replace?

MR. BOWDEN: The piping that was replaced was the recirc reactor water cleanup, the core spray, RHR piping.

MR. ARMIJO: So that was all for IGSCC?

MR. BOWDEN: That is correct. And it was all replaced with the 316L.

MR. ARMIJO: 316L? And you are also using noble metals and hydrogen I guess?

MR. BOWDEN: That is correct. Optimum water chemistry is basically the combination of noble metals, zinc and hydrogen water.

MR. ARMIJO: Okay, and that is all of your I guess stress corrosion cracking mitigation program?

MR. BOWDEN: That is correct.

MR. ARMIJO: And have you had - how long has that new material been in service, 316 nuclear grade?

MR. BOWDEN: That was roughly - I was going to say the mid-1980s.

MR. ARMIJO: And since then I'm sure you've inspected it, have you had any problems with it?

MR. BOWDEN: We have not seen any

indications of any additional cracking.

MR. ARMIJO: Thank you.

MEMBER SHACK: I could find noble anywhere in the license renewal application, so - I found optimum water chemistry. Does that mean you don't have a commitment to continue the noble metal?

MR. ZAREMBA: We are committed to continue - we just completed our online application here recently at the end of the month and will continue to do that.

MR. BUMAN: The confusion may be coming on in within our licensing basis, optimum water chemistry, it includes, one of the pieces is the noble metal applications.

MR. ARMIJO: Okay, maybe I'm getting ahead of myself, but somewhere along the line, are you going to mention - talk about the condition of the course routes and whether you have had any cracking or any kind of mechanical repairs, things like that?

MR. ZAREMBA: We did not plan on doing that, but we can address that.

MR. ARMIJO: Yes, just briefly.

MR. McCLURE: Yes, this is Tim McClure on behalf of the applicant. We've been doing inspections to the BWR VIP requirements, and our last inspections

we have some cracking in the core shroud, and we have flaw evaluations that we use to predict until the next inspection times.

MEMBER ARMIJO: Have you had to install these --

MR. McCLURE: No, we have not installed any repairs on our shroud.

MEMBER ARMIJO: You are monitoring the inspections?

MR. McCLURE: Yes, we are monitoring.

MEMBER SHACK: Some cracking means what? How many feet?

MR. McCLURE: I wouldn't - I don't know off the top of my head what the lengths are.

MEMBER ARMIJO: Are they big?

MR. McCLURE: I would say they are not big. We have one that is longer than a couple of the other welds, but I would not say - I would not consider them big myself.

MEMBER SHACK: And I saw that you had inspections for top guide pins, but have you actually looked at the top guide itself?

MR. McCLURE: Yes, we've looked at the top guide. We recently looked at it under VIP-183, where we looked at 13 cells, and we typically look at

the top guide using ASME Section 11. Also we do - so we do BT-3, and then also under the VIP-183, we EBT-1 on the lower two-inch part of the grid on these 13 cells.

MEMBER SHACK: This is not the monoblock type, this is a lattice work that comes together?

MR. McCLURE: Yes, correct.

CONSULTANT BARTON: Did you find any cracks in that?

MR. McCLURE: No, we didn't find any cracks.

MEMBER SHACK: How early did you go to hydrogen water chemistry of some sort in your life? As soon as you replaced the piping? Or did that come later?

MR. BUMAN: The hydrogen water chemistry came into play in 2003 is when that went active. We have been doing noble metal applications. The first noble metal application was in 2000; we had another one in 2005, and we just completed our online application 2010.

If there are no other questions, finally, the large motor and pump program, the majority of our large pumps and motors, we've been systematically replacing or rebuilding them back to original specs

with others in progress based on prioritization. It's coming out of our large motor program.

The above demonstrates our ongoing commitment to managing aging components and maintaining the facility. If there are no other questions, I'd like Dave Bremer to discuss the license renewal application process.

MR. BREMER: Thanks, Dan.

The first step in license renewal is system scoping. The project developed guidelines based on NRC-endorsed NEI 95-10 Revision 6 to ensure consistency in scoping plant systems. Systems and structures, intended functions, were identified by reviewing plant design basis documentation and compared against 10 CFR 54(a) criteria. For Cooper the definition of safety related is consistent with the definition in 10 CFR 54(a)(1).

Electrical systems and instrumentation control components and mechanical systems were placed in scope without exclusion. Scoping for alpha two for both direct effects and indirect effects due to spatial relationships utilized site component data bases, piping and instrument drawings, and isometric drawings. Spatial mapping throughout the plant was performed to define the proximity of safety-related

cable and piping components to non-safety related systems.

The AT results were verified by conducting comprehensive plant walk downs.

One scoping related open item in the SER associated with the condensate storage tank one alpha will be discussed later on in our presentation.

Scoping resulted in 58 mechanical, 38 electrical and 22 structures that were placed in scope, which are comprised over 20,000 discrete passive and long-lead components and structures that were subject to aging management review.

CONSULTANT BARTON: I have a question: service water. The service water pumps are in scope, but yet the cooling system for them, the HVAC which cools I imagine the pump motors is not in scope?

MR. BREMER: The service water pumps themselves, they are self air cooling. The HVAC for the service water pump room is not accredited nor required to support the intended safety function. It's failure would not cause a loss of that intended safety function; therefore it was not in scope for either alpha one or alpha two.

CHAIR STETKAR: Dave, I have a couple of electrical questions. And you are not planning to

talk about electrical things. I guess probably for timing considerations we should try to get through some of the more interesting items, but I'd like to make sure you've got a couple of electrical people on board here.

MR. BREMER: We do.

CHAIR STETKAR: I'll come back to that later, because I want to get to the more interesting items first here.

MR. BREMER: Moving on to Aging Management Review then. The next step, of course, after scoping and screening, is to conduct the aging management review. As with scoping we developed project guidelines from NEI 95-10. Other industry documents were utilized that identified aging effects based on material types such as the EPRI mechanical structural and electrical handler.

Aging Management Review was performed system by system, operating experience was conducted in parallel to allow for timely feedback into the aging management review. The Aging Management Review generated 30 reports cataloging over 3,200 aging management review line items for common material environment groups as reflected in the application.

Ninety percent of the aging management

review line items used nodes alpha through echo, meaning they were consistent with the comparable line items involved.

The next step was to identify the engineering program that would effectively manage the aging effects during the extended period of operation and compare the program elements to GALL. Review of existing programs against the 10 elements in the standard review plan concluded that the majority of existing programs were either consistent with GALL without any changes, or required some enhancements.

Eleven existing and one new program took exception to GALL. In over half of these the exception was due to the adoption of a different but acceptable application of an ASME code program such as the risk-informed attribute to our ISI program. In a few programs the exception was taken - was conservative to GALL. An example that would be like in the diesel fuel oil program where we cite an ASME standard that is more stringent than the standard cited in GALL.

There were a couple of programs where our exception was merely a differently aging management program cited to manage the same aging effect, such as for example the inspection of the structural portions

of the metal-enclosed bus work. We do that within the metal-enclosed bus program versus deferring that to the structural monitoring program for GALL.

CHAIR STETKAR: Dave, you had to mention it, so I might as well ask one other question. The metal enclosed bus work scope, I noticed that the winding - there is a metal-enclosed bus on winding X of the startup station service transformer to switch gear buses 1A and 1B. That is part of your offsite power recovery path. That particular transformer has two secondary windings. There is an X winding and a Y winding. There's the Y winding which - the supply from the Y winding to buses 1C and 1D, is that also a metal enclosed bus stop?

MR. ZAREMBA: We'll have Dan answer that.

CHAIR STETKAR: If it is I was curious why that is not in scope, because if that fails you'll take out the transformer.

MR. RUCKER: Okay, it's Roger Rucker for the applicant. That is a metal enclosed bus, with a Y winding, is, those two buses are nonessential loads.

CHAIR STETKAR: What happens if that - you have a fault inside that bus, though, what happens to the transformer?

MR. RUCKER: The winding is considered

oscillation between the two.

CHAIR STETKAR: Doesn't protective relaying trip that transformer off and lock it out?

MR. RUCKER: Not necessarily. It's going to depend on what the fault is. I mean you know some of the faults will clear before the protective relaying.

CHAIR STETKAR: If you have a large arc-over fault inside a metal enclosed bus it's not going to clear very quickly.

MR. RUCKER: That's true. But anyway, that's not in, now as far as inspections and everything that were done, they look at, for license renewal, that path is not in.

CHAIR STETKAR: I understand. I just don't understand the rationale because it would seem that a fault in that bus would have the same effect on the transformer as a fault in the bus that is enclosed.

MR. RUCKER: Well, the transformers themselves are not single failure. That's one of those two transformers for the two independent sites so --

CHAIR STETKAR: I understand, but it's part of what - that transformer is part of what you

are including credit for in your station blackout power recovery task. That's what it's in scope.

MR. RUCKER: It's one of the two.

CHAIR STETKAR: It's one of the two, but that's why it is in scope.

MR. RUCKER: Correct.

CHAIR STETKAR: And that's why that bus work, that bus stuff is in scope.

MR. RUCKER: That's correct.

CHAIR STETKAR: Okay, thanks.

MEMBER SIEBER: And that is not fused, correct? Sometimes they fuse them, but typically --

CHAIR STETKAR: I couldn't - it's just a one-line diagram. Just looks like it's hardwired down to - breakers at the buses.

MEMBER SIEBER: Well, it's on the primary side of the transformer.

CHAIR STETKAR: Well, this is on the secondary side, it's a dual secondary side winding. Okay, thank you.

MR. BREMER: Concurrent with the performance of the Aging Management Review TLAAs were evaluated in accordance with 10 CFR 54.21© (1). Cooper identified and evaluated TLAAs in these five areas. Calculate fluence used in the reactor vessel

neutron embrittlement analysis, methods were used consistent with Reg. Guide 1.190 to determine the fluence for 54 EFQY. We evaluated metal fatigue analyses and included consideration for environmental effects in the fatigue monitoring program.

We validated that the EQ program manages the effects on aging on components with EQ TLAAs. Fatigue TLAAs were evaluated for core shell and supports, including attached piping and penetrations. We identified a TLAA for core plate bypass plug life, for which we established a program enhancement within the BWR vessel internals program, but will direct replacement of those core plate bypass plugs prior to the end of the qualified life.

MEMBER SHACK: What is the material of those plugs?

MR. BREMER: I'd refer that to Ken Thomas.

MR. THOMAS: This is Ken Thomas for the applicant. The plugs themselves are stainless steel, but they have an Incanel spring in them.

MEMBER SIEBER: Did you do any reconciliation of overall plant cycles to determine fatigue?

MR. BREMER: Could you repeat that

question?

MEMBER SIEBER: Did you do any overall examination of plant cycles, startup, shutdowns, major transients, to determine fatigue life of systems?

MR. THOMAS: We did look at - this is Ken Thomas for the applicant - we did look at the past cycles, and considered that in our fatigue monitoring program, and then we're scaling that up for the 60-year life and we'll be revising our fatigue monitoring program to account for those additional cycles.

MEMBER SIEBER: Now did you estimate the history of the past cycles? Or did you actually go back and examine the operating history?

MR. THOMAS: We did both. We have been tracking the fatigue life cycles for many years, and then we also went back and developed a histogram to show what the actual cycles were. And they were very close.

MEMBER SIEBER: Okay, thank you.

CHAIR STETKAR: Do you have that histogram with you in any of your backup material?

MR. THOMAS: I don't believe so.

CHAIR STETKAR: Because there were quite a few questions about how that histogram was developed and used from the staff, and there are a couple of

items that - you projected 60 cative usage factors are rather high. And we're rather interested in how they were derived, because they are well above one. And I noticed in your presentation you are not - you didn't come prepared to actually speak about that. But perhaps when the staff comes up they can talk a little bit about it.

MR. BREMER: Well, we are prepared to address any of your questions now.

CHAIR STETKAR: Let's see how the timing goes. I certainly want to get to the bigger technical issues first, and see how the schedule works out.

MEMBER SIEBER: That is a significant issue.

CHAIR STETKAR: It is. We'll see how the timing goes.

MR. BREMER: Commitment management. The actions to implement the new programs and enhance existing programs constitute the list of license renewal commitments that we have placed within our Cooper Nuclear Station commitment tracking system. The tracking process effectively tracks and manages all regulatory commitments including license renewal commitments. The regulatory commitment tracking system was established consistent with industry

guidance, industry and NRC guidance, and receives periodic inspection by the NRC as part of the regulatory oversight process.

With a relatively short timeframe until we reach our period of extended operation we began implementation last year starting with mechanical one-time inspections as well as the (e)(1) electrical cables and connections program. We also commenced the analytical work for enhancing the existing fatigue monitoring program.

Participation and information sharing within the NEI license renewal implementation working group is allowing us at Cooper to incorporate lessons learned and operating experience into new program implementation. Commitments to develop implementing procedures for the new programs are being integrated with emerging industry issues where applicable.

If there are no further questions, I will hand it off to Mr. Hottovy to discuss the technical items of interest.

CONSULTANT BARTON: Your inaccessible electrical cable issue, what is that? I understand it's a one time and you are committed to do that program as a one-time or whatever. Have you done anything in the last 36 years looking at manholes,

duct bank, and assessing any cable damage in finding water, et cetera?

MR. BUMAN: Yes, we have. The initiative that is referred to here as an EPRI initiative for underground cables, and we are participating in that particular initiative also, and having that in there. We have examined for all of the - for the systems that are in scope, and the cables associated with the systems that are in scope for any of the manways, all of those manways currently either have a sump or a drain to a manhole that does have a sump. Those are alarmed, and so we do have monitoring as far as going in there. We have also done examinations inside of the manholes looking for signs.

MEMBER SIEBER: Did you ever find any water?

MR. BUMAN: We found some water in those. We have found water in some of the other non - the systems that are not in scope, in some of those. Those do not have sumps that are in there.

MEMBER SIEBER: Okay.

MEMBER BONACA: Did you experience the leakage from buried piping and tanks?

MR. BUMAN: Leakage from buried pipings and tanks, to my knowledge we have not experienced any

leakage from buried piping and tanks. I'd turn that over to Phil.

MR. LINER: We have had some leaks on some piping that is not in scope, like our potable water system, and sprinkler system. One system that is in scope -- we have failure on our fire protection system. There was a fracture as opposed to an age-related degradation.

MEMBER BONACA: Because it wasn't clear from your description of operating experience whether you had any leakage in fact. So those leakages were from components not in scope?

MR. LINER: That is correct. The one from a component in scope was a valve fracture on our fire protection system.

MEMBER BONACA: Thank you.

MEMBER SIEBER: What caused the crack?

MR. LINER: There had been some excavation in the area previously, and so there was some settling that occurred, that cast iron valve.

CONSULTANT BARTON: But you did find corrosion in buried diesel fuel storage tanks, right?

MR. LINER: Corrosion in the buried steel?

CONSULTANT BARTON: Fuel oil storage

tanks, corrosion was discovered, and you guys put some kind of lining on there.

MR. LINER: Yes, this is Phil Liner for the applicant. Yes, we went in and recoated our diesel fuel oil storage tanks. The coating was coming off, so we went in there, we did measurements, thickness measurements of the tank. And we also did a recoating of that tank, those tanks, both of them.

CONSULTANT BARTON: What is the anticipated life of the coating?

MR. LINER: The anticipated life of the coating is exceeding the 10-year time period that we have for inspection. The warranty is like 10 - 20 years. It will significantly last beyond --

CONSULTANT BARTON: Ten to 20 years?

MR. LINER: For the warranty.

CONSULTANT BARTON: And when did you install it?

MR. LINER: In 2004.

CONSULTANT BARTON: And it's going to last through another 20 years of operation?

MR. LINER: We will inspect it. We have a PM for periodic inspection. So we drain the tank, clean the tank, and inspect the coating.

MEMBER SIEBER: I presume that corrosion

is caused by water accumulation?

MR. LINER: This is Phil Liner for the applicant. The concern, yes, would be water. We also do some other things to recirculate the tank, take out particulate, some other things to make sure that we don't have a water issue. We are actually going in and sucking the tank out and cleaning that out without going in and inspecting the tank.

MEMBER SIEBER: Right, just stick a hose in and suck off the bottom.

MR. LINER: That is correct.

MR. HOTTOVY: Okay, as David noted we'll go ahead and move into the open items and I will be discussing the first three items on the slide, and then Mr. Roman Estrada will discuss the containment in service inspection program. And for each of the items what we will do is we will provide a brief background along with discussion towards resolution, and then entertain any questions as we go along.

The first item of concern is the condensate storage tank, 1A, and its associated piping in scope for license renewal. And the reason we didn't do that initially was that that system is considered nonsafety-related at Cooper and it does not have a direct impact on a safety function. And

therefore we had initially not included it. And it's important to note, and I will show you on the next slide here in a minute, that our condensate storage and transfer system includes four tanks. We have the two condensate storage tanks, one alpha, one bravo, and then emergency condensate storage tanks one alpha, one bravo. And it's the emergency condensate storage tanks that do have a direct function with regard to safety function, and those tanks as well as their piping have always been in scope.

CONSULTANT BARTON: It wasn't clear in the application.

MEMBER ARMIJO: Those are much smaller tanks.

MR. HOTTOVY: Yes.

CONSULTANT BARTON: How big are they?

MR. HOTTOVY: 50,000 gallons each, there's two of those. And their lines are safety-related high pressure cool injection pumps.

CHAIR STETKAR: That Tank 1A though, I don't want to belabor this point because you are including it now, but 1A is actually included for modes four and five as an alternate source of water in case the torus is drained, right?

MR. HOTTOVY: That is correct.

CHAIR STETKAR: Thank you.

MR. HOTTOVY: Okay, so from the diagram here just quickly, the system - it's a simplified diagram, but like I said there are four tanks, and you will note that there is a dashed line put through that diagram, and that separates the nonsafety related portion of the system from the safety related. Everything below the line is in scope for license renewal under 54.4(a)(1), and as noted the condensate storage tank 1A and the piping to the suction of the isolation valves of the core spray and RHR lines have been included in the scope.

So if there are no further questions we will move on to the second open item. CNS' license renewal application discussed a one-time inspection of small bore piping socket welds as discussed in the GALL versus the periodic inspection, and initially we did not initially convert to use of a volumetric examination method. Based on industry operating experience and some history at Cooper where we did find we had three small bore cracks that we had identified in our history review. Staff did feel that it was more appropriate for Cooper II including a periodic examination of the small bore welds using a volumetric technique. So with respect to resolution

we have completed destructive examination of a sample of small bore piping socket welds that bounded the condition for which they were caused by. And we are - which will also provide ongoing - will - we are - in resolving this issue we are committing to doing periodic volumetric examinations of the weld connections going forward.

CHAIR STETKAR: Todd, you mentioned, someone mentioned earlier that you have a risk informed in service inspection program. Is there any prioritization of these socket welds for the systems based on risk, or are you using other criteria to determine which particular welds you are going to sample for testing?

MR. McCLURE: This is Tim McClure on behalf of the applicant. Yeah, with the risk informed program, these particular three that we have selected are in the risk informed program, and they were selected using the EPRI methodology for risk informed. So they have a risk ranking if you will.

CHAIR STETKAR: And the scope of your program goes down to these whatever the lowest sizes form, couple of inch?

MR. McCLURE: Yes, it does.

MEMBER BONACA: But that means, I

believe, for the one-time inspection they are looking for susceptibility of the component and not necessarily for the risk.

MR. ZAREMBA: Your question is the susceptibility for the --

MEMBER BONACA: The criteria with respect to risk. You have a population of sockets, and they are looking for the susceptible ones. If you inspect them you will find there is no problem, there is no problem about the others. So that is the process behind that kind of inspection. Are you using that one?

MR. ZAREMBA: Tim, the criteria that our program has in terms of establishing the risk and susceptibility?

MR. McCLURE: Well, the criteria looks at the consequence of the failure, and then it looks at the damage mechanism to arrive at a risk ranking, so it looks at different failure mechanisms or damage mechanisms. It looks at thermal fatigue and other type of damage mechanisms.

MEMBER ARMIJO: But when you did those destructive examinations of those sample socket welds that had cracks, did you confirm what the cause of cracking was, whether it's fatigue or stress-corrosion

cracking?

MR. HOTTOVY: Let me first clarify the 12 that we sampled did not have crack indications. That was to further bound the extent of --

MEMBER ARMIJO: Okay, they were just sampled. There was nothing going on?

MR. HOTTOVY: That's correct, and there were no cracks or any signs of an aging mechanism associated with those welds.

MEMBER ARMIJO: Okay, so you didn't find any kind of degradation on socket welds in your one-time inspection?

MR. ZAREMBA: Let me clarify. We had some operating experience where we had three socket welds that were cracked. As an extended condition we went and took a broader sample and destructively examined 12 addition - we had an issue on our drain piping that these three socket welds that were cracked, and it was - we had a root cause that determined it to be vibration induced, and as an extended condition we went to bravo site and other similar valves, and that's what we did with these 12.

MEMBER ARMIJO: All right, thank you.

MEMBER SIEBER: There are a number of situations that cause cracking in socket welds. One

of them in the time period when your plant was originally built I don't see anybody old enough --

MR. RUCKER: Now Jack.

MEMBER SIEBER: Except Harold and I and John. But sometimes during construction when they would make up the weld, they would take the pipe and put it into the socket all the way to the bottom and then make the weld. If they were just metals that causes a crack at the weld, years later. Do you know if steps were taken through construction not to make the welds up that way? For example, some construction companies either have procedures to withdraw the piping a certain amount or they put spacers in there to make sure that the pipe did not actually bottom out when they made the welds.

MR. BUMAN: Unless you have it, I'd have to go back to the construction specs.

CONSULTANT BARTON: Have we got any evidence?

MR. THOMAS: Ken Thomas for the applicant. The construction code did require that you do that spacing. I'm not aware were in use at the time to make sure that they had the adequate spacing. But we have not seen any failures due to not following the code.

MEMBER SIEBER: Do you think you would be able to tell the difference by looking at a failed weld?

MR. THOMAS: If we cut it open, yeah, you'd see the spacing.

MEMBER SIEBER: And you have not found anything that would indicate that that condition is present in your plant?

MR. THOMAS: That is correct.

MEMBER BONACA: Anyway, I would like to go back to the issue, is it clear to you what's the objective. It is one time inspection it is to demonstrate that the effect isn't happening anywhere. So you do it once, looking at the most susceptible location. If conversely you go to a periodic program then you are looking at the risk associated with components. It is important that you define which one you are following.

MR. ZAREMBA: And we are committed to do periodic inspections. That was a discussion with the staff and resolution of this we are committed to doing periodic --

MEMBER BONACA: So in that case you are not going to look at susceptible locations, but you are looking at all the components?

MR. ZAREMBA: Correct. That is correct.

MR. HOTTOVY: We can move to the next slide.

So in concluding this item, just to answer your question, Mario, this is essentially where we are at. We are committed to doing the periodic volumetric exams, and our plan is to examine three Class 1 small-bore socket weld connections in the upcoming spring refueling outage in March, 2011, and then we will also be including the periodic examination in each 10-year ISI interval going forward.

And the reason I skipped the previous slide - that was the plan history - we've pretty well discussed it.

So are there any further questions?

MEMBER SIEBER: The volumetric examination, will - if it is at the right time you will be able to see whether that gap is there or not, so I would look for it.

MR. ZAREMBA: We will.

MEMBER SIEBER: Thanks.

MR. HOTTOVY: Okay, so we will move on to the third open item. And this is regarding the buried piping in tanks inspection program at Cooper. You

know her license renewal application, we did describe development of buried piping and tanks' aging management program at Cooper that is in conformance with the industry initiative that is currently out there that the industry has worked up of recent and we felt at the time that what we were doing in that program satisfied the Rev. 1 of the GALL, and then we had some additional request from the staff on some of the changes in buried piping and tanks inspection program based on the recent industry experience. So in recognition of the significant of the industry challenge and the recent learnings, we are further enhancing our aging management program for buried pipes and tanks to include inspections of high risk piping systems that are in scope for license renewal prior to entering the period of extended operation.

Additionally we'll be looking at fire protection in condensate piping regardless of how the program ranks that, and I'll get into how the program works. But this will result in a minimum of six piping inspections prior to PEO, and follow it up with the periodic inspections and any additional piping segments as we go through PEO based on the ranking process that is within the buried piping and tanks program.

So the table that is on that slide basically shows the comparison of where we were originally and where we are at today that we are going beyond the GALL Rev. 1 was indicating, and we are going to be committing to inspecting six piping segments within the PEO.

Okay, the next three slides I'd like to just walk through the buried piping and tanks program. First, the industry initiative that's titled Guideline for Management of Buried Piping was issued in January of this year, and it's fairly comprehensive and includes critical elements of an effective inspection program aimed at preventing structural and leakage concerns related to buried piping. And in addition to following that guidance, our program, we are modifying it as necessary as new industry information comes forward. We are going ahead and modifying that, and as an example, based on the recent OE, we have modified our program to include not only buried piping which is piping in contact with the soil, but we are also including underground piping which is the piping that may be in pipe chases and is not in contact with the soil.

And as described in the initiative our program will include a ranking process that will be

used to set priorities and inspection frequencies, where the highest priority is always placed on the safety-related piping as well as any piping that contains radiologically contaminated fluids.

So this slide shows the elements of the industry, and it also sets the milestone dates. And as I noted CNS is committed to a program that contains these elements, and we are committed to meeting the dates, and in fact we are currently on track with those milestone dates. The next date of course is June 30th, 2010, but in parallel with the procedural development and oversight, we are moving forward with the risk ranking element of the program. And we have committed resources, and have also obtained some expertise in the area of developing that ranking program, using some additional personnel, they have done this at other nuclear power plants.

And this ranking process looks at each segment of buried and underground piping, and it takes into consideration the function of the piping, the location, the materials of construction as well as the soil composition and contact or in the location of that piping, and it also considers the cathodic protection and extent to which it was detected.

As noted on a previous slide the piping

that supports plant safety functions or carries radiologically contaminated fluid receives the highest ranking within this process. Risk ranking portion of the program will result in a comprehensive database that contains both buried and underground piping and will ultimately be used to prioritize the plan and track the inspection activities.

And we are currently expecting to complete that by the end of the third quarter of this year, so we will be moving ahead in front of the milestones as we develop our program.

In addition to developing the buried piping and tanks program, and we got in a related discussion here, we have done some inspections of our service-water piping. We have done an internal visual as well as volumetric exam, and the internal piping - and that's the underground - or excuse me, the buried piping. And we have also done some inspections of the diesel generator fuel oil piping where we have had some excavations with respect to the coating and conducted volumetric exams of that also. And in both cases for both systems the piping was found to be in very good condition.

CHAIR STETKAR: Todd, give us any just general indication, you mentioned both buried piping

and underground piping, the differences being subtle but we are all aware of those differences these days. You said that your service water piping is buried, which means it's in contact with soil. What other - are there other piping systems in your plant that are underground but not buried, and what are they?

MR. HOTTOVY: I will refer that over to Phil.

MR. LINER: This is Phil Liner for the applicant. As far as the license renewal systems, we have not identified any underground piping at this time, but there are underground piping in some of the other systems.

CHAIR STETKAR: But nothing in scope for license renewal as yet?

MR. LINER: Not for license renewal as yet. We are still going through out risk ranking process, which part of that is identifying all the piping and verifying its actual conditions, and then including it in the risk ranking process.

CHAIR STETKAR: I stepped in front of John. What systems in scope for license renewal then have buried piping in contact with soil?

MR. LINER: In buried piping we have the diesel fuel oil system, we have service water, plant

drains, fire protection, condensate, high-pressure coolant injection and nitrogen and standby gas treatment.

CHAIR STETKAR: HPIC is underground?

MR. LINER: Yes, it's in piping that is buried between the control building and the our reactor building. It goes to our emergency condensate storage tanks.

MEMBER ARMIJO: Could you describe - go ahead, Jim.

MEMBER SIEBER: Does your environmental monitoring program examine various site areas around buried piping for tritium above background? And have you ever found any?

MR. ZAREMBA: It does. We have welds - Bob will give you the details - we have one weld.

PARTICIPANT: Bob Bialky speaking for the applicant. Our environmental monitoring program, we have 11 wells on site, ground water monitoring wells, that we monitor for radioactive contamination. We also monitor surface water areas, such as our sewage lagoons. We also monitor catch basins, and some manholes.

MEMBER SIEBER: Have you found any tritium levels above background?

MR. BOWDEN: We have detected some tritium above background, but less than our offsite dose assessment manual for voluntary reporting requirements.

MEMBER SIEBER: Have you done anything to find out why it's above background?

MR. BOWDEN: Yes, we took the analysis, combined it with our hydrogeologic study and had an independent consultant review that data, and we've determined most likely it's due to downwash from our elevated release point.

MEMBER SIEBER: Okay.

MR. ZAREMBA: We are in the process of new wells to validate the information that Bob just described.

MR. BOWDEN: I would like to add that we are drilling wells, four additional wells, two in the vicinity of the well that had the highest tritium concentration, and then another well based on industry OE. And then a fourth well based on the recommendation of that consultant.

MEMBER SIEBER: I would just point out that that has been an issue at a number of plants, and it does not - it runs afoul of your environmental program and your defensive public health and safety if

you don't pay attention to it and don't correct it.

MEMBER ARMIJO: I had a question on your cathodic protection system upgrades, what systems are you protecting using this technique? And is this - can you describe the cathodic protection system?

MR. LINER: This is Phil Liner for the applicant. We are adding additional cathodic protection. They did a survey that evaluated where we were at, so we are going in and we are basically - we are adding new test stations to monitor the system, and some anode ground beds in locations of the piping.

MR. ZAREMBA: What systems now do we have?

MR. LINER: The systems that we are adding - or that we're adding or connecting these two are circ water, diesel fuel oil, air removal, condensate, fire protection, turbine equipment cooling, control air, roof drains, those are the ones we are adding some connections to.

MEMBER ARMIJO: Okay, so these are some sort of dc, live dc, or is it like a zinc --

MR. LINER: It's a rectifier.

MEMBER ARMIJO: Okay.

CHAIR STETKAR: There was some - reading through the various reports there was some indication

that the existing cathodic protection system may have had problems or may have been connected with reverse polarity for example, and that you were performing a program to evaluate that. What are your results from that?

MR. LINER: We reviewed each one of the CRs that were identified that were potentially were an area where the cathodic protection could have an adverse effect on the piping, and each one of those, it was not the case. It was kind of the wording in the CR or the corrective report that made it sound like it was something that would be a detrimental effect, but that was not the case.

CHAIR STETKAR: Have you inspected any of the piping that could have been susceptible to that?

MR. LINER: We've inspected the piping of - the service water piping, some of that, and we had good results. Some of the other locations were over in the fire protection area and we performed one inspection when we had that valve failure, we looked at the coating of the piping there, and the coating was in very good condition. And the piping was too.

CHAIR STETKAR: Thank you.

MR. HOTTOVY: Okay, so in resolution of this open item, as I discussed Cooper is underway and

completing development and the implementation of the buried pipe and tanks program, and which is in accordance with the industry initiative, and also we've got a couple - in coordination with the cathodic protection upgrade, we are going to take advantage of that project that is ongoing this year. We are going to complete some additional inspections, piping inspections, and also prior to PEO we will be completing inspection of the high risk buried tanks, and at least one segment of high risk, buried or underground piping for each safety related system that is in scope for license renewal that is going to include - and we just talked about some of these - service water, diesel generator, diesel oil, HPCI, and standby gas, and we plan to inspect fire protection and condensate which are both in scope systems during the cathodic protection upgrade project.

Unless there are any other questions, I would like to turn it over to Roman to discuss the final open item.

MR. ESTRADA: Thank you, Todd.

I am Roman Estrada, I'm the design engineering manager. I'll discuss the fourth open item, discuss that the applicant has not demonstrated that the effects of the torus degradation will be

adequately managed so the intended function will be maintained for the period of extended operation.

I will be providing a review of our torus health, and our inspection recoating program that supports a torus recoat after three years into the period of extended operation.

The structure I will be talking about in the right-hand corner of the diagram up here is the torus. Thank you.

The current inspection program was established in 2001 in accordance with our ASME Section 11 code. The inspections were set up on inspection frequency based on observed pitting in the torus.

CHAIR STETKAR: Roman, before you get wound up on the torus, because you are getting wound up, can you go back to the previous figure? There you go. I had a question: this has nothing to do with the torus, where the dry well shell enters the fully embedded concrete area down on this figure, the right-hand corner of the drywall, is there any indication of corrosion at that junction, and what type of sealant material if any is at least in the area of the dry wall that you can see?

MR. ZAREMBA: Ken, go ahead.

MR. THOMAS: Are you talking external or internal?

CHAIR STETKAR: Both, actually.

MR. THOMAS: Internal there is a shield around they concrete at the bottom which we inspect as part of the containment in service inspection program. We have found some minor degradation and have replaced that seal. I think it is a Morton Thiacol product, but I don't remember the exact number. But that is included in the scope of ISI.

CHAIR STETKAR: Have you seen any indication of corrosion down behind that seal?

MR. THOMAS: We haven't seen any indication of corrosion in the drywall liner itself, and externally there is a sand cushion underneath the containment, and we have done a vacuum test on the sand cushion to detect moisture. We have not detected any moisture. We have committed to perform those vacuum tests prior to the PEO.

MEMBER ARMIJO: So the sand is still in there? You haven't removed the sand cushion?

MR. THOMAS: No.

CHAIR STETKAR: And just - I was making notes - you said you have not detected any corrosion down around the seal on the interior?

MR. THOMAS: We have not detected any leakage from the reactor.

MEMBER SIEBER: They haven't detected moisture. You don't know about the other.

CHAIR STETKAR: Well, they said they hadn't detected any corrosion. They looked at the seal. You said you inspected the seal, on the inside. I walk talking about the inside.

MR. THOMAS: There was no evidence of corrosion.

MEMBER SIEBER: The outside is also a vulnerability.

MR. THOMAS: Right, but outside we have not detected any signs of moisture or any leakage from the cavity that would cause corrosion problems.

CHAIR STETKAR: And on the inside you said you had seal inspections.

MR. THOMAS: We've done seal inspections as part of the scope of containment ISI.

CONSULTANT BARTON: How often is that inspection done on the seal?

MR. THOMAS: Say again.

CONSULTANT BARTON: How often do you inspect the seal of the drywall to the concrete floor? That seal, internal seal? How often is it inspected.

You said you found degradation in the seal and you replaced the seal. The period where you could have had leakage between inspections is what I'm getting at. So how often is that seal inspected?

MR. McCLURE: This is Tim McClure on behalf of the applicant. I believe that inspection is once a period, that would be every 3-1/3 years under ASME Section 11, but I would have to confirm that.

MEMBER SIEBER: Have you done any volumetric testing of the shelf fitness in the area around the seal so that you could make a judgment as to whether corrosion is occurring on the back side regardless of whether you found moisture or not?

MR. THOMAS: Ken Thomas for the applicant. We didn't do any volumetric examinations, but when we excavated the bad seal materials, we did do inspections of the liner to see if there was any evidence of corrosion. And we didn't find any.

MEMBER SIEBER: But that would be on the inside, right? I guess I believe you when you say you don't have any leakage from the refueling seal, but I guess I don't believe that also. Because as far as my experience has been that they all leaked a little bit sometime, and there is no place for it to go but down into the sand bed region, it flows down and just sits

there and so it expends its chemical energy and processes during that process.

CONSULTANT BARTON: How did you do the vacuum tests, on the drain piping coming through the sand bed, or what?

MR. THOMAS: That is correct. They did a vacuum on the drainlines coming from the sand cushion. And then use that to detect whether there was any presence of moisture, and no moisture was detected.

MR. BUMAN: It was also used to detect to make sure that the sand cushion is not becoming blocked or occluded.

CHAIR STETKAR: Now you can get warmed up on the torus.

MR. ESTRADA: Okay. Our inspected started in 2001, and it was and it was set up on an every two outage frequency, and this is based on the observed pitting that we saw in the submerged section of the torus.

During these inspections we did a de-sludging and cleaning of the torus, and a 100 percent visual inspection of the wetted area for any recording of pits based on our established criteria.

Our next inspection is scheduled for March of 2011. I have a couple of photographs here of the

wetted portion. This slide shows a picture of our Bay 9 observation area. This is a 12 inch by 12 inch observation area. The 17-year monitored section of the torus that we use as the primary data reference point for predicting our torus shell corrosion metal-loss rates.

The pits displayed are well within our inspection program margin requirements, and have had no impact on the torus containment structure either individually or cumulatively based on their spacing.

MEMBER ARMIJO: Could you explain what we are looking at here? You have several colors. You have white spots, you have black spots, you have a red spot, and you have a gray background. So tell what is what.

MR. ESTRADA: The gray background is our zinc oxide coating, and the dark spots are the pitting that we are talking about as far as in our control observation area. The white spot over here is actually a repaired recoated.

MEMBER ARMIJO: And that red spot?

MEMBER SIEBER: The red is a strawberry.

(Laughter)

MR. ESTRADA: It's a marking there. You can see the grids, the one-inch grids.

MEMBER ARMIJO: So your zinc oxide coating is in some sort of an epoxy, or what is it? Just - can't be pure zinc oxide.

MR. PULLMAN: This is Josh Pullman on behalf of the applicant. John, could you come up?

MR. ESTRADA: John, if you could come up and explain what the zinc oxide is specifically.

MR. CAVALLO: John Cavallo for the applicant. The coating that you are looking at is an inorganic zinc coating which is fairly common in the Mark I BWRs. It's a 85 percent of zinc and the dry film metallic zinc. The binder is an ethyl silicate, which is often referred to as water glass. It's an ethyl silicate that has reacted with water or moisture from the air to form the binder. But the primary constituent is metallic zinc.

MEMBER ARMIJO: Metallic zinc.

MR. CAVALLO: Metallic zinc, yes, sir, in about 20 micron sized particles.

MR. ESTRADA: This slide shows kind of a mixture of the repairs on one side that has been recoated and one of the pitting that is being smoothed out and we're getting that ready for recoating.

This is an example of a pit that we found. Typically a pit is about the width of pin, 5/16th inch

nominal, that's what inside the circle center there; it's getting ready for a pit repair. And the next slide actually shows where you put the patch on it, which is about a 1-1/2 to 2 inch diameter patch that goes over that pit.

MEMBER ARMIJO: Before you patch it do you measure the depth of the pit?

MR. ESTRADA: Yes, there is a micron that goes down, goes into it and measures each one of the pits.

MEMBER SHACK: Yes, there was - in the SER there was a corrosion rate of 2.6 mils per year for those pits, and so it's based on a 33 mil pit over 13 years, and it doesn't seem nearly enough to account for your deepest pits. Is that some sort of average rate? That can't be your maximum corrosion rate, is it?

MR. ESTRADA: I'd refer that to Josh Pullman.

MR. PULLMAN: This is Josh Pullman on behalf of the applicant. That is correct, that is a mean corrosion.

MEMBER SHACK: That is the mean corrosion rate.

MR. PULLMAN: That is correct.

MEMBER SHACK: And the maximum corrosion rate?

MR. PULLMAN: We've seen corrosion rates as high as 5-1/2 mils.

MEMBER SIEBER: You had a couple that were alone in the wall in very critical areas, right?

MR. PULLMAN: That is correct.

MEMBER SIEBER: Did you do an analysis to justify those?

MR. PULLMAN: Currently that is contained with our structural calc of record, it does a width-depth proximity analysis.

MEMBER SIEBER: Okay, thank you.

MEMBER ARMIJO: The purpose of your zinc coating was to protect the steel. But it doesn't seem to protect against this pitting problem. Is that pretty much to be expected, or what's the purpose of the zinc coating if it's not to protect the steel?

MR. PULLMAN: It's a gross protection measure intended to capture a majority, and we combat the pitting by managing it with our inspection program.

MEMBER ARMIJO: So if there is a defect in the coating you would expect pitting to occur? A small defect will lead to a small pit?

MR. PULLMAN: That is correct.

MEMBER SHACK: And you are getting 3,000 pounds of sludge, in mass conservation, where is the sludge coming from? That's 3,000 pounds per outage.

MR. ESTRADA: Typically the sludge comes from the interface piping that is tied to the torus. We don't get a lot of sludge coming from the zinc oxide itself.

MEMBER ARMIJO: No, I would think not.

(Simultaneous voices)

MEMBER ARMIJO: So somehow the pitting is a mechanism that is not hindered by the zinc?

MEMBER SHACK: If it isn't there.

MR. ESTRADA: It goes through the coating and then it hits the metal surface, then we start getting into more of the general corrosion that you get. Maybe John can explain that a little bit more.

MR. CAVALLO: We have been studying - John Cavallo for the applicant - we have been studying this pitting phenomenon since the late `70s and early `80s. Yes, sir, Mr. Sieber, I am as old as you. (Laughter)

What we found is that we actually have an oxygen concentration cell. It's not a failure of the inorganic zinc coating to perform well. In fact it is

performing extremely well. What you have is a small particle of usually iron oxide that will fall on the - near the bottom of the torus and cause an oxygen concentration cell where we use up the oxygen concentration cell where use up the oxygen under that particle which galvanically eats the zinc at that point. At that point we then expose the steel under there and the corrosion cell continues until it morphs into a general corrosion phenomenon. What we have done in the industry to make up for that is to do more frequently cleanups of the torus to remove that 3,000 pounds of sludge which mitigates this phenomena.

CHAIR STETKAR: Did I read somewhere that you do not have a normally operating torus clean up system, filters, demineralizers, and so forth? Is that correct?

MR. ESTRADA: I don't know if there is a normal - I'm not aware of the Mark Is having a normal - we control our overall chemistry by basically a feed and bleed, diluting out and processing the water out then refilling.

MEMBER ARMIJO: Where is the bleed, from the bottom of the torus or from the sides?

MR. BUMAN: We actually use --

MR. ESTRADA: We run our RHR system which

would pull water from the low level of the torus where the strainer. While we are recircing it through testing we go ahead and dump off and make up with condensate makeup which is purified water. 30,000 gallons.

MEMBER SHACK: Now is your sludge generation typical? It seems very high to me.

MR. ESTRADA: Typical of?

MEMBER SHACK: Of Mark I containments.

MR. ESTRADA: Since we have been doing the inspections, since '96 --

MEMBER SHACK: No, but in the other plants.

MR. ZAREMBA: I can speak for my experience at Fitzpatrick containment. Remember we are de-sludging once every other outage, so it's not - it's over a three year period, and when we do sludge at Fitzpatrick actually we're in the same ballpark.

MR. ESTRADA: When we established the criteria back in the '96 time period, we were pretty consistent with the rest of the industry as far as what sludge ring we were going to start cleaning the torus out with.

MEMBER SHACK: Is your sludge removal rate - or your sludge generation rate changed since

the '96 period? I mean just looking at these three outages, you see 1,000, 3,000 and 3,000. What is different about the 1,000?

MR. BUMAN: Overall that is trended by the system engineering. They do look at that. They do have - what sometimes gets a little bit difficult is how they are measuring it and dewatered weight, and how they had it. I know there is some data on that. I can get the specifics if you would like.

MEMBER ARMIJO: So assuming you understand the mechanism of what is causing the pitting, this iron oxide laying on the coating and degrading it and ultimately pitting, so you are desludging on a periodic basis to minimize that.

MR. ESTRADA: Right, to minimize the amount of galvanic interface you would get.

MEMBER ARMIJO: And then repair it?

MR. ESTRADA: You clean it and then repair those pits that we found.

MEMBER ARMIJO: And that is done how often?

MR. ESTRADA: Every three years.

MEMBER ARMIJO: Every three years.

MR. ZAREMBA: Now we are - you will see Roman will get to - we are proposing that we will do

that every outage.

MEMBER SHACK: I mean you are generating 5 - 600 pits per outage.

MR. ESTRADA: I have a slide coming up that kind of goes over the history. These are the inspection areas that we look at as far as our ASME inspection criteria. We have a near penetration areas, a general shell region, and also the near ring girders.

What you see from that - this is how we established our inspection criteria, and this is based off our torus containment structure calculation, which establishes our containment structural limits. So for the near penetration, the near ring girder, and the general shell we have criteria for pit depths and whether we do a recoat and also when establishing any kind of engineering evaluation.

These provide us an operating margin to ensure that we don't impact the design margin that is established on behalf of our torus containment structural calc, either by individual pits or any cumulative spacing.

All of the deep pit types that we establish on there get an additional engineering evaluation that goes back and looks at this structural

calculation to ensure that we haven't - that we are still within our allowable values for that. So these are operating margins, and then there is a design level associated with that.

And as we discussed before, this is what we are seeing as far as the number of pits we've had since we have been recoating the torus. We have 3,800 pits and the coated, as we talked about the 1-1/2 inch to 2 inch surface area, that equates out to about 145 square feet. From a volume standpoint or an area standpoint, I'm sorry, that's about 1.13 percent of our overall wetted surface area, which is 12,850 square feet. It's a very small amount associated with the whole surface area of the torus.

Now what this graph here is talking about is a chart representing the pit depth. And we talked about that day nine observation area we had, our 17-year item, receiving no recoating. The green line reflects what we are actually seeing from a pit depth based on the actual mean corrosion rate that we are seeing in the torus. And then what we did is, we established a 95 percent confidence line which is the red line up there which is based on the mean plus two sigma associated with that.

Now if we assume no change in corrosion,

so it stays at a constant corrosion rate, that black line on top there is what we estimate over the next 10 years to the 2020 timeframe as far as pit depth. But as we discussed a little bit before, we are actually seeing as it goes from a kind of pitting induced corrosion and it gets into the metal surfaces and it starts to become more general, that corrosion kind of curves off, and that logarithmic line which is the blue one is what we are actually seeing and estimating for as far as our pit depth.

Both those numbers are well below our criteria for that bay which is 90 mils. So from 20-20 time period we still believe we'll be within that criteria, before we even start to do any repair of that or refill it.

MEMBER ABDEL-KHALIK: Have you had any recurrence in areas or in pits that were repaired 19 years ago?

MR. PULLMAN: Josh Pullman speaking on behalf of the applicant. We have not had any failed recoats in our inspections.

MEMBER RAY: Maybe I missed it. Is this pitting completely random or is it - is it located systematically?

MR. ESTRADA: I've got a chart coming up

here to show where they are at.

We've been doing the inspections since the ASME inspections in 2001, and our maximum depth pit that we've actually found was 92 mils, which is 13 percent of nominal torus shell. Similar to other deep pits we found in the criteria I talked about earlier, this pit was compared to our torus containment structural calculation record and found acceptable based on its width, depth and proximity.

This is what I talked about, this is how we map out the pitting in the torus. You see the brown stuff on the chart there is actually where we have done refills. Typically you find the big circular items are around our penetration areas, and that's because based on our structural count we determine that to be our highest concern as far as our structural analysis, because we have zero tolerance for any pit in that area, so we go ahead and recoat them. So you will see most of the refills are done around the penetration area.

MEMBER ARMIJO: That is where the recoats are done. But does that mean, are there any regions where there are pits that are not recoated?

MR. ESTRADA: Yes, if you go back to the previous slide - keep going back - this one right

here. If you look here like the near ring girder, those are noted, in a general shell noted. If it's below 50 mils for a near ring girder, or below 90 mils, we just note that. And we do not have to do a recoat on that.

MEMBER ARMIJO: That pit could continue to grow.

MR. ESTRADA: Right, and we estimate that as part of our analysis what that growth would be, and still we were within our bounds for getting to the point where we actually do that analysis.

MEMBER ARMIJO: Have you ever measured one of these pits that you don't recoat, measure it periodically to see if it is behaving asymptotic of linearly?

MR. PULLMAN: Josh Pullman on behalf of the applicant. That is the purpose of our Bay Nine observation patch. That is 17 years of unmitigated growth that we have been tracking and that is where that graph comes from.

MEMBER ARMIJO: Okay, so that does represent pits that you have been monitoring?

MR. PULLMAN: That is correct.

MR. ESTRADA: We don't repair the pits on this observation area, so we can use that as our

baseline for corrosion rates.

MEMBER ARMIJO: Okay, I'm glad you said that, but that is an awful looking spot there.

MEMBER RAY: But again you responded to the question of, are these randomly located are they in some systematic location.

MR. ESTRADA: I guess what we saw is that typically you will see where we recoat is around the penetration, because our criteria are so low there. As far as randomness around the torus, if we have any data.

MR. SKOUROP: This is Brian Skourop on behalf of the applicant. Typically most of the pits that we see in the general shell area are near the invert of the torus simply because that is where the sludge tends to collect, and start that galvanic process that creates the pit. But generally we believe it's a random process.

MR. ESTRADA: This is - over the last three inspections periods, this is what we consider the deep pits, and these are the ones that get the additional engineering evaluations to ensure that we are still bounded by depth, breadth and spacing from a cumulative standpoint. You can see the ranges in each area from minimum depth to maximum to average

especially in those areas.

In summary, our torus health is acceptable in accordance with our ASME Section 11 inspection process, which is in effect a managing of the aging effects of the torus shell and its structural integrity. Our analysis based on corrosion rates supports a torus design margin through 2020. We are going to increase our inspection and sludge removal frequency from every other outage to every outage. And we will be performing a recoating of the wetted portion of the torus within three years after entering the period of extended operation.

Any additional questions?

CONSULTANT BARTON: This sludge removal is now what?

MR. ESTRADA: Every other outage.

CONSULTANT BARTON: It's every other.

CHAIR STETKAR: But since you are going to a two-year fuel cycle that will be still a sludge removal going forward every two years instead of every three years now?

MR. ESTRADA: That's right, so we'll still get an extra year off of that.

MR. ZAREMBA: We are not going to to the two-year cycle until 2014, and we are planning to do

the recoat, the outage after that, so it will be 2016 when we do the recoat.

CHAIR STETKAR: So you will get two more sludge removals between now and 2014, right?

MR. ZAREMBA: Yes. Counting 2014.

MEMBER ARMIJO: You say your analysis supports the design margin through 2020. What about after 2020?

MR. ESTRADA: We are going to recoat in 2016.

MEMBER ARMIJO: So you are saying - and if you recoat you are going to recoat with the same material?

MR. ZAREMBA: No, we are going to - we are going to look at the industry experience and the operating experience and see what material is the best. What we don't want to do is introduce a different with any kind of flaking, strainer clogging, anything like that, and create debris issues. So we haven't decided which material.

MEMBER ARMIJO: You haven't decided, but in 2016 you will do a complete recoat of the torus or just partially?

MR. ZAREMBA: Recoat of the wetted portion.

MEMBER ARMIJO: And you haven't seen any kind of degradation of the --

MR. ZAREMBA: In the hot upper portion, above the water.

MEMBER ARMIJO: Okay, no pitting, no localized attack of any kind.

MR. PULLMAN: This is Josh Pullman on behalf of the applicant, in the upper portion of the torus we haven't seen any pitting, no localized attacks. We have seen some light general area corrosion, but that is very restricted.

MEMBER ARMIJO: What about the water line, have you seen any unusual corrosion at the water line in the torus?

MR. PULLMAN: That is covered under our inspection program, and yes we have seen some pitting and some general corrosion at and just below the water line.

MEMBER ARMIJO: But no worse than below the water line?

MR. PULLMAN: It's consistent with the rest of the torus.

MEMBER ARMIJO: Thank you.

MEMBER SHACK: Just coming back to that curve where you had the mean pit depth, is that a - do

you toss new pits into that mean every inspection, or is that a fixed population of pits?

MR. PULLMAN: What we've seen over this data, going back to 1991, and for the first three data points there we didn't see any new pit formations. In the last two we have seen new pit formations, and that is all averaged into that value.

MEMBER ARMIJO: That kind of implies that the new pits are growing faster than the old pits. It's not a very comfortable --

MR. ESTRADA: As you go through the original coating, then once you hit the shell it starts to slow down for general corrosion rate, which is why you start the curve --

CONSULTANT BARTON: The coating is depleting also. You are losing protection all the time.

MR. ESTRADA: With that I'd like to turn it over to Art Zaremba for final comments.

MR. ZAREMBA: I think there were some areas where we had other questions perhaps that we would like to address from the committee members. This concludes our formal presentation, but we have folks here to answer any other questions or topics you would like to pursue.

MEMBER RAY: Do you have a plant-specific simulator?

MR. ZAREMBA: Yes, we do.

CONSULTANT BARTON: I have a question on your aging management program for above ground steel tanks. Where you have done some work on I believe is the fire water storage tanks, reinsulated, put a seal around the bottom which wasn't sealed between the bottom of the tank and the foundation. The only tanks you address are fire water storage. Now how about other steel tanks above ground that have similar configuration and problems, and have you looked at, since there have been years when there has been no protection between the tank bottom and the foundation, so you've got water, whatever. Have you done bottom thickness measurements on these tanks?

MR. ZAREMBA: Yes, Phil, why don't you talk a little bit about our above-ground tank program and the work we do.

MR. LINER: This is Phil Liner for the applicant. The above-ground tank program, until we included condensate storage tanks, in one alpha, was just the fire water tanks.

CONSULTANT BARTON: That was my question, are you going to include the other above-ground tanks?

MR. LINER: We are going to include the condensate storage tank, 1A, in that also. Part of the above ground storage tanks is that we will be doing bottom thickness measurements to make sure that we have a good bottom on that.

CONSULTANT BARTON: Have you done any up to now?

MR. LINER: We haven't done thickness measurement on the bottom. We have done visual inspections of the fire tanks, inspected the coating to make sure it was good. And on the fire tanks themselves they have a sand bottom, and it's sloped away from the center to the outside.

CONSULTANT BARTON: But you can't see between that flanged joint and the foundation, the center of the tank.

MR. LINER: The center of the tank to the outside, it slopes away from the center of the tank, so it slopes to the outside. So if you have leakage on the inside or water on the inside it would slope to the outside.

CONSULTANT BARTON: Is that bottom in constant contact with the sand?

MR. LINER: Yes.

CONSULTANT BARTON: And the sand could be

wet and it could be corrosion from the sand to the external bottom surface, and without taking measurements how do you know that --

MR. LINER: And we will be taking measurements of that.

MR. ZAREMBA: So historically we have not done that.

MR. LINER: We have not done it, but we will be doing thickness measurements of the bottom.

MEMBER ABDEL-KHALIK: Do you have a system health report for the first protection system?

MR. ZAREMBA: Yes, we do.

MEMBER ABDEL-KHALIK: The color-coded system.

MR. BUMAN: I don't know off the top of my head. That is something that is monitored on a quarterly basis and is updated, and I just don't know that. Todd, are you aware of what the fire protection system health is?

MR. HOTTOVY: I don't have that right offhand.

MR. BUMAN: We can get that information.

CHAIR STETKAR: Your fire protection water tanks you say are provided with clean water. Where does your clean water come from? Not the

Missouri River?

MR. BUMAN: No, they are fed from basically a well onsite there.

CHAIR STETKAR: Okay, all right.

You had some problems with your diesel fuel oil day tanks. And I noticed that you had to clean them out, and now you inspect them every 4-1/2 years. What is the basis for that inspection frequency? It seems like a strange inspection frequency. Especially given the historical problems that you had.

MR. LINER: This is Phil Liner for the applicant. The day tank inspections are based on the maintenance window for the diesel, the major maintenance. There is not an EPRI PM basis for those types of tanks. But what we did is we set it up based on the major maintenance for the diesel. And that's it.

CHAIR STETKAR: Three years.

MR. LINER: It's 4-1/2 years, three cycles.

(Simultaneous voices)

CHAIR STETKAR: Now, will that change in the future to once every six years when you go to a two-year cycle?

MR. BUMAN: One of the things we have to look at when we go to the 24-month cycle is we will be looking at all the PMs and doing the reevaluation including any of them that are on diesel, so they will be adjusted in accordance with that. Right now I can't tell you whether that - one way or the other, but we always maintain them to make sure that we maintain margin within the vendor recommendations.

CHAIR STETKAR: We have a couple of minutes here, I'm back to electrical things. The inspection reports indicated that you found water in three or four manholes, and apparently as I understand it at one time the cables in those manholes were considered to be in scope for license renewal and you have removed them from being in scope. I'm first interested in the manholes themselves. Did those manholes have sump pumps in them with alarms in the control room and low points like your in scope manholes?

MR. VanWINKLE: Marshall VanWinkle with the applicant. The manholes that you are speaking of do not have sumps.

CHAIR STETKAR: They do not? Okay. Now the justification for removing those cables from being in scope, as I understand it those particular cables

that are routed through those manholes are for AC power to the control power for the switchyard control house or whatever you call it; is that correct?

MR. BUMAN: They feed the battery chargers.

CHAIR STETKAR: They feed the battery charger.

MR. BUMAN: The battery charger is in the switch house.

CHAIR STETKAR: What is your station blackout coping time at Cooper?

MR. ESTRADA: Four hours.

CHAIR STETKAR: What is the life of the batteries, rated life of the batteries in the switchyard?

MR. BUMAN: The analysis that we have that they would be exceeding, they are basically sitting there in a standby condition. So I don't know if I have a calculation. But clearly greater than four hours and we go back from that.

CHAIR STETKAR: I would hope so. I have actually had answers contrary to that. If the batteries indeed are rated for greater than four hours it seems justified to remove those cables from being in scope. If the batteries have less than a four hour

rating it's not at all clear how you can get the circuit breakers reclosed out in the switchyard.

MR. BUMAN: Well, and the reason these were removed from scope is because you actually have to have power back on site to be able to feed the electrical power back out to those.

CHAIR STETKAR: And I can see creative ways of getting power from diesels and things to get those if you need them.

Any other members have any other questions?

This went better than we had planned. If that is the case, I think what we will do is take a break early and come back and hear from the staff. And what we'll do is we will recess until 10:30.

(Whereupon at 10:09 a.m. the proceeding in the above-entitled matter went off the record to return on the record at 10:29 a.m.)

CHAIR STETKAR: Okay, we will come back into session. Before we have a presentation from staff, I understand that the applicant has at least an answer to one of our questions that we had earlier, so I wanted to make sure that we follow up on that before we get to the staff's presentation.

MR. ZAREMBA: Yes, thank you, this is Art

Zaremba. The question was, the first system health, and the color of that program, system health, is white at this point.

MEMBER ABDEL-KHALIK: And what is the main reason?

MR. ZAREMBA: The main reason is we have a temporary modification configuration issue where we have swapped on our surface water halon (phonetic), the main tank system, we've swapped the pressure alarm to a backup.

MEMBER ABDEL-KHALIK: Thank you.

CHAIR STETKAR: So I guess at this time we will turn it over to the staff. Brian, did you have something to say?

MR. HOLIAN: Yes, this is Brian Holian, again, division director, license renewal. There were a couple of introductions I missed this morning I just wanted to pick up on. I know why I missed one of them because I think he was late this morning and he is late showing up here. But Tam Tran is our project manager. I think he is just at the restroom; he'll be coming in in a second. But Tam you last saw a couple of years ago on then Wolf Creek project that he had, and when he finished that project he picked up Cooper, and he's the project manager. Bo Pham, the branch

chief, is up at the table, and he'll be able to start the presentation here. Again, Greg Pick, the senior reactor inspector.

One other introduction, we have several branch chiefs and technical staff in the audience to help us with presentations and questions, one also is Dr. Allen Hiser, I wanted to mention him. Dr. Hiser has been with us in license renewal from the Division of Component Integrity for about eight or nine months now as our senior level adviser, and does an awful lot on the quality reviews of our safety evaluation reports, so I wanted to highlight that.

With that I know there was one kind of left over subject from this morning was metal fatigue and the fatigue type issues. The plant does have several components that are close to those numbers, and I know the applicant mentioned that they can still give additional detail on that, and we have a tech reviewer also that could talk to some attention to our reviews on that aspect.

With that I'll turn it over to Bo Pham.

NRC STAFF PRESENTATION SER OVERVIEW

MR. PHAM: Thank you, good morning. My name is Bo Pham, and as Brian said, I'm the branch chief for the project review here, and Tam Tran who is

the project manager is not here yet, so I'm going to try and stall as long as I can. Or at least get started with the presentation process.

Tam's presentation is going to take you through the review process from our perspective and that will definitely highlight some of the findings that we had, and the open item issues that we spent some time on this morning, he will give you our perspective on those items.

And Greg is going to give you the regional perspective of what was doing the regional perspective.

Actually if you don't mind, we'll just skip through and jump into Greg's presentation first.

CHAIR STETKAR: Sure, that's fine. `

MR. PICK: Good morning, I'm Greg Pick. Can everyone hear me?

I was the lead inspector for the Region 4 part of this license renewal process. The inspectors on the team were representatives from Region 4, Region 3 and Region 1. We looked at the scoping and screening and non-safety related systems, and we looked at 23 of the 40 aging management programs, which included 10 of the 11 new aging management programs.

We during our inspection identified no concerns. We thought the drawings provided a good division between the non-safety related systems affecting safety-related systems. For the aging management programs, the minor items corrected, the applicant had removed the thermal insulation and provided a seal at the bottom of that tank during the outage that occurred, right after we were on site, so that answered one of our concerns.

During the fire water inspection, one of their procedures did not have them inspect hose reel gaskets. They just modified the procedure. For the flow accelerated corrosion they revised their amendment. All of their flow accelerates erosion operating experience to date at the time of our inspection was due to high flow down the pipes and they didn't have any valves or odd components, and they had limited their monitoring of flow accelerated corrosion to ultrasonic testing. We thought that was a narrow view. They modified their application to include visual radiography if needed.

CHAIR STETKAR: Greg, on operating experience, it's one of my pet subjects, I thought you guys did a really good job on going back and looking at both the staff's audit team and your team. How far

back did you look in their condition reports, how many years back?

MR. PICK: We look 10.

CHAIR STETKAR: Ten years back? Good.

MR. PICK: And in the area of structures, one of the Region 1 representatives was Suresh, and this was his fifth Entergy site. They use a corporate level procedure. They may have a site specific procedure but a lot of the guidance is in the corporate level procedure. And they committed to better define the quantitative and qualitative guidance so that if it's a different inspector, and maybe the inspection is once every five years and once every 10, so they could get more consistency by putting more criteria in the procedure.

And then the largest issue out of our inspection was the containment program, the data that is in the report was obtained from my review of the IWE reports. Each was about 20 pages long and had lots of detail on all the activities that occurred, and the applicant of course gave a good description of how they did their inspections and the results they found.

For the current license basis the largest pit was the 0.92 inches. It was near one of the

penetrations. It was coated with the epoxy to arrest any corrosion.

With the commitment to recoat the torus and do the increased inspections, that answers the concern that the region had about managing the effects of aging, because the recoating should prevent some of the problems that the applicant described about an hour ago on what caused the corrosion.

The next slide is what I obtained for a picture of the torus, to show the wetted portion. I asked them when they do the recoating, they are going to recoat all of the metal that is below the water, not just the torus wall.

Very similar picture. The white is where they coat it with the epoxy. That was just measuring the width and depth of a group of pits so that they could do their evaluation for their structural calcs to demonstrate that they met the IW code.

Another picture of the Bay 9 Grid. They explained that in detail about how they monitor. There's 42 points on that grid that they take and average.

This is the - this is a typical findings at the Cooper Station at the downcomer and the tiger stripe rusting that you will see below the water line.

That is the best picture - best still I could get. I had their underwater video from their IWE inspection and created this still, and that is a ring girder showing the surface general corrosion.

Any questions?

CONSULTANT BARTON: Yes, I had a question. In your report you indicated that this part of your looking at the plant on your inspections that the conditions discovered by your team inside the torus room, you noted you found significant leaching deposits, water stains on the torus supports, and around RHR and HPCI piping penetrations. And I question the material condition of that area. Is that just a - the worst you saw? I guess - it's your team there walking around their site. What is your overall assessment of the material condition of this plant?

MR. PICK: Actually the team thought the material condition was very good.

CONSULTANT BARTON: I read this and I kind of wonder.

MR. PICK: I understand that. That was the worst of what we saw in that area.

CONSULTANT BARTON: That area. How about the whole plant?

MR. PICK: The whole plant itself, the

interior environments of the reactor building.

CONSULTANT BARTON: Piping system and struts.

MR. PICK: They are painted, struts are not corroding very much with the interior environments they have.

CONSULTANT BARTON: Okay, I just saw that and I wondered whether this was just an example of what else I would see walking around there.

MR. PICK: We were down in the manholes for the medium under-voltage cables that were clearly within scope, inside the pump rooms with the sump pumps, they had some rust on some of the ports on the walls, but nothing that you wouldn't expect to see. We went under the service water floor. It was a very hot, humid environment, and there is a lot of surface rust, but nothing structurally bad. Some spalling.

CONSULTANT BARTON: Okay.

MEMBER ARMIJO: Could you go back to your picture of the Bay 9 Grid. Now did your inspectors or did you actually see this area not necessarily at this time or when you did your inspections?

MR. PICK: That is on the interior wall, the torus, under water. This was a still that I created from their - they had a video of their last

inspection that they provided to me. I went through it and clicked to get this still.

MEMBER ARMIJO: Well, maybe this is a question to the applicant. I still see those red spots. There's quite a few of them. Are those precursors to the more severe pitting or flaking of the coating? Are those rust spots? Can somebody answer that?

MR. CAVALLO: John Cavallo with Enercon Services, Inc. I was the level three that has observed these videos, and those are basically drips of dye penetrant fluid that was used during torus, interior torus mods. It's a red dye.

MEMBER ARMIJO: It's a red dye?

MR. CAVALLO: It's a red dye. It's totally inert, and it's - it just - because the zinc is somewhat porous it's impossible to remove.

MEMBER ARMIJO: So it's not --

MR. CAVALLO: No, sir, it's not a precursor to corrosion, no, sir.

MEMBER ARMIJO: Okay, got it, thank you.

MR. PICK: And they are in the cycle letter that we issue, the licensee remains in the response column over the last year, the findings were green and all their performance indicators are green.

So the applicant's ability in their corrective action program is considered they can manage themselves.

So the inspection conclusions were that scoping of non-safety structure systems and components and application of the aging management programs to those components, structures and systems were acceptable, and that the inspection did find that there was reasonable assurance existed that aging effects will be managed and the intended functions maintained.

Specifically to the torus, we agree that they met the ASME code. That was based on review of the calculations and inspection reports. Concerns that this relates maintaining design control to ensure containment integrity. With the recoating we believe the recoating will solve the problems that we were seeing, that they will be able to maintain the containment integrity.

I read their letter that they submitted yesterday, and with that, we believe that will close our unresolved item.

That would end my presentation. Are there any questions?

MR. PHAM: If we can start back over again, I'm glad to see that Tam Tran is all right. So

we skipped to Greg's presentation, and now we will start back at the beginning again.

MR. TRAN: Basically - well, my name is Tam Tran. I'm the project manager for future nuclear station licensing renewal projects. I have with me Bo Pham, my branch chief, who will be providing some response back to your questions today. He has been looking closely at the SER, and we try working very hard with the applicant on some of the open items that Greg mentioned a little bit ago.

MR. PHAM: Can I just make one statement. With regards to some of the open items we have received two recent letters from the applicant, April 28, and one yesterday. The staff has received them but they haven't been put through the docketing process. So for all intents and purposes, as of today the staff hasn't had the time to fully consider the applicant's responses. But we have been in discussions with them regarding what they would come in with.

CHAIR STETKAR: And those two letters address all four of the open items from the version of the SER that I've seen.

MR. PHAM: I believe so, yes.

MR. TRAN: Okay, the presentation now. I

will begin with a brief overview of the scope of this presentation, license renewal review, audit inspection that Greg just covered, and now I will cover - and then we will follow with the results, specifically a technical item of interest, from Section 2 and Section 4 of the SER.

The license review application was submitted in September, 2008. The current facility upgrade license end date is January 18, 2014. The plan is a BWR Mark 1 design with 2419 megawatts thermal, and 830 megawatt electric.

Next slide. The SER - the staff was aided with the audit review and additional information provided by the applicant in response to requests for additional information items that we issued to the applicant. The information collected from the audit, RAI response were used to develop the SER open items that we received from the applicant and dated April 6, 2010.

The SER with open items contained four open items, one confirmatory items, and three of the four open items are upgrade-related.

We can now go to the results of the audit. NRC's review team conducted audits and inspection. The onsite review with the aging management program

audit in April of 2009. This was followed with the scoping and screening methodology audit in May 2009. During the AMPR that the staff performed independent review of the applicant's condition report for applicable upgrade experience, and that's formulated in our RAI and some of the open items that you see in the SER.

The Region 4 conducted two inspections in July and August, 2009.

So now we will discuss about the results of the SER. Section 2 discuss structure and components subject to aging management review. Section2.1 covered scoping and screening methodology for license renewal applications. The staff concluded that applicant's methodology meets the review criteria for the standard review plan and in accordance with the rule.

Section 2.2 covered the plant-level scoping results of the relevant systems and structures. The staff found the result by the applicant also meets the review criteria in the standard review plan and in accordance with the rules.

For the mechanical system the staff identified one open item related to the scoping of the condensate storage thank that you have heard some

discussion this morning by the applicant.

Next slide.

CHAIR STETKAR: Tam, before we get into that, let me ask you the same thing I asked the applicant. As I was going through the scoping and screening analyses, one of the questions that I had is back to that electrical enclosed bus duct from the - I guess it's the Y winding of that transformer. Is your electrical group confident that indeed failures of that duct will not degrade the ability to supply offsite power to the plant.

MR. TRAN: We have the reviewer of the specifically look at the station's blackout recovery scenario, and we can have the reviewer come up to the mike and address that.

MR. DOUTT: I am Cliff Doutt with license renewal. We are aware that that is in scope. What is in scope and what comes off. That was in scope based on station blackout recovery. We had a scoping on that. We have - we are aware of it. We are going to have to take a look to get a better answer for you.

CHAIR STETKAR: Okay, good. Thanks.

MR. TRAN: So that is something that we will take away and do our best in the --

CHAIR STETKAR: I was just curious is

there was any more in depth examination on your side.

MR. TRAN: We will look at that.

CHAIR STETKAR: Thank you.

MR. TRAN: Okay. In accordance with 10 CFR 54.;4(a)(2) the ;condensate storage tank and associated flow pad is within the scope of license renewal because the staff finds that during emergency core cooling operations the condensate storage tank can be used as a source of cooling to support safe shutdown.

If the torus is drained, the condensate storage tank would be the only source of cooling for the ECCS. The staff was notified by the applicant that the license renewal application is amended. As Bo mentioned earlier we received some late information on that, and the staff will make a confirmatory determination for this item in the final SER.

In addition the staff identified a number of components that were later brought within the scope by the applicant. These components provided support functionality to needed mechanical systems intended functions, and according to 10 CFR 54.4(a) the function of the components were not obvious at the time the applicant performed this scoping and screening activity. And some examples like the main

steam, the off gas, and so on.

CHAIR STETKAR: I notice you had several questions about the boundaries and the scope in the off gas system. The final scoping includes only the liquid drain lines from the off gas to the radwaste system. Is that true?

MR. TRAN: I have the reviewer, Dan Gardocki.

MR. GARDOCKI: This is Dan Gardocki. I reviewed the scoping in screen for the plant drain systems specifically with the air removal and the off gas system, and we were comparing what the applicant submitted in the LRA and reviewing the FSAR. And we found some discrepancies, and that's why we submitted a number of RAIs. The isolation function from the condenser out to the isolation valves with the air injecters either mechanical or steam jet ones. We identified that issue, and the applicant has included those lines all the way up to the isolation valves.

And then on the other side of those valves going out to the elevator release point there is a holdup line that has a large quantity of water in it. It drains down into the elevator release point sump, and we had those lines evaluated because they had the potential to flood the sump.

And in that same area there was a question about the barrier for ground level release, and the staff was not sure of the applicant's scoping of that function. And as you can see in the RAIs they redid the scoping of that function changing some systems from an (a)(1) function to an (a)(2) function, because we wanted to get a good grasp of what should be in scope on that function.

So we added those components to the scope, and the same thing, in the OG building there were some safety related components in the OG building that we discovered, and we had them add the fluid fill components in the OG building in scope. So there was a significant number of components added to scope to encompass all the different areas in those two systems, the AR and the OG.

CONSULTANT BARTON: I notice there are a lot more RAIs on scoping and screening in this application than there has been in a long time.

CHAIR STETKAR: There were in the off gas in particular.

CONSULTANT BARTON: A lot more in the whole scoping and screening section.

MR. GARDOCKI: The staff did - this is Dan Gardocki from Balance of Plant - we did an in

house review of this application. We didn't send it out to a contractor. So I trained up a team of Balance of Plant personnel and we all went to the site to do walk downs of specific systems that we had, so we had a really good understanding of the systems, went out there, walked them all down. So when we came back we wanted to definitively define all the functions, all the components that support those functions. And there were some RAIs that brought a whole lot of equipment in. We weren't confident in the turbine building, their methodology of saying below grade of the turbine deck. In the basement they wanted to screen those out, but we saw there were openings of mechanical hatches into areas with safety-related components that they brought into scope. There were lines on the main steam isolation valve boundary that needs seismic supporting. So we did a very comprehensive review.

CONSULTANT BARTON: Maybe you guys ought to do that more often.

MR. PHAM: Well, we did what we did as Dan indicated in the case of Cooper, but the Division of License Renewal is taking some efforts in house to improve the quality or give feedback to the industry at least on the future quality of the applications.

We are taking some efforts to try to understand the statistical significance of the systems that they are including in scope versus what we are looking at, some of their components database.

CONSULTANT BARTON: Looking at a drawing versus looking at it in the field makes a big difference is what I got out of what you guys just said.

MR. PHAM: So we haven't formalized this internal effort. We are trying, yes, but we will be gathering information and feeding it back to industry.

MR. TRAN: Next slide. Section 3 cover aging management - by the way are there any more questions on that - Section 3 cover aging management review. This slide provides a summary of all the aging management programs that were reviewed by the staff and documented by the SER.

Review of the aging management program was performed mostly by the license renewal audit teams, and Dan mentioned he went out on one of the audit teams, as documented in the SER. Our division also provided contributing review for the SER.

The other team review 30 aging management program of the 40 AMP. Four are plant specific, 15 are consistent with the generic aging lessons learned

before, recommendations; seven had exceptions; and nine have enhancements. Five of them have both enhancement and exceptions.

As a result of the staff review one open item was identified related to the management of small bore piping socket welds. The applicant responds to manage the aging effect in the socket welds by means of visual inspection. The staff finds volumetric examination is needed for small bore socket welds by management. The staff reviewed industry upgrade experience and noted that some failures in the small bore piping socket welds were initiated through a crack from the inside diameter.

As covered earlier the applicant agreed to provide a response, a supplement for resolution of this item, and the staff would confirm this item for the final SER.

MEMBER SHACK: How small would the small bore pipes be for the volumetric exam?

MR. TRAN: I have a reviewer here.

NAME UNKNOWN: Mark Ku (phonetic) with Division of License Renewal. Up to a two-inch diameter.

CHAIR STETKAR: Up to? Or down to?

NAME UNKNOWN: Two inches in grade.

Down to.

CHAIR STETKAR: Down to a one-eighth inch?

NAME UNKNOWN: We've seen three-quarters of an inch. I just want to note that from the staff's perspective on that issue, and you will see this come up as an open item on some of the other reviews as well, including Duane Arnold which is what we are looking at right now. The point wasn't to try to force the industry to come up with an unknown methodology to do this. The logic that the staff found of saying, we don't have an industry qualified means of doing it, therefore, we can't do anything else but visually inspect it wasn't adequate, because in the case of looking at it visually it's merely a leakage detection and by the time you notice that failure is probably imminent by then.

MEMBER SHACK: Okay, that was my first - next question is --

MR. PHAM: Our goal --

MEMBER SHACK: There is no qualified technique to do this. You are just asking for kind of a best effort?

MR. PHAM: I think some licensees out there have tried demonstrated techniques depending on

the size.

MEMBER SIEBER: Dye penetrant sometimes will work.

MR. PHAM: So that is our goal is to try to get the applicant to come to provide a best effort to look at the technical, depending on the size and location of the flaw and the piping is, to take that into consideration.

CHAIR STETKAR: Bo, is the staff's approach to this evolving over time if that is the term that I could use? Because I thought in some previous renewal applications you have approved at least focused visual inspections of risk significant or highly susceptible lines, however people have classified them?

MR. PHAM: I can't speak on too far in the past, but I think the - Bart could probably tell you that we looked at some operating experience from the industry out there. And we understand that small bore piping usually don't lead to safety significant. However, due to the fact that they have caused unscheduled scrams at least raise a flag out there that maybe we need to have somebody take a look at it.

MR. HOLIAN: Yes, this is Brian Holian, and I'd just add to that, you have seen it brought up

as an item on discussion on several of the last plants in the last couple of years, and even before that we have looked back at all the SERs. And we've had discussions with NEI. We have quarterly meetings with NEI on kind of hot license renewal topics. And station blackout varied by being the small bore piping have found the agenda for several of those meetings. I think even the ACRS weighed in maybe three or four years ago on was the staff going too far maybe and requesting destructive examinations of small bore, so somebody around there might remember that on a couple of applications.

But it's always been in GALL. Small bore piping has always been in GALL, even internationally overseas they are seeing experience, some of it being high-cycle fatigue obviously, but still requirements that have caused plant trips, and so operating experience is still there. So it is in GALL. Once again we are just trying to register what we can do. We do see several plants out there that are making better attempts at techniques, and we are trying to get that uniform.

MEMBER SHACK: But I mean I'm sort of with John, this is the first one at least that I remember --

CHAIR STETKAR: This one I see a lot more emphasis on --

MEMBER SHACK: The volumetric.

MR. HOLIAN: Yes, we think that more than visual is what the staff is looking for when that's appropriate. So --

MEMBER ARMIJO: What do you mean by volumetric? Is it UT, radiography, would dye penetrant be acceptable, or what?

MR. PHAM: I think at this point we are not describing a specific technique for the applicant. Different applicants have come up with different proposals.

MR. TRAN: Yes, something that gets below the surface. Because as indicated --

MEMBER ARMIJO: So a dye penetrant wouldn't make the cut.

PARTICIPANT: Again based on operating experience review the staff in formal review separately, and this is what staff found out. They are have been more occurrences in socket weld failure affecting 55 operating units. Thirty two of the cases have led to shutdowns. And then the failure mode needs to be SEC or fatigue. And what is important, most of the failures are caused by cracks initiated

from the inside surface of the weld. You know as we - this is a contentious point. Is visual or surface examination adequate? We are saying no, because by the time you detect something, you detect a leakage, it's already failed. On the other hand we also looked at methodologies out there. We just talked about volumetric. It's mostly UT. In previous reviews we have seen one case that an applicant performed RT for other reasons, but took credit as a volumetric method. Somehow I think in Coopers case we just found out today they have performed destructive examinations, 12 they mentioned, 12 back in the '04-'05 timeframe, and now they can you know take credit. At least a look at the result, and we will consider that.

As far as UT, the staff found out recently a number of licensees have developed procedures qualified for the site specifically and qualified for some of the applications, if they are looking for SEC or fatigue, and this is what we found out. Although not qualified for seismic, they provide a go/no-go result. The reason if y0ou look at socket weld configuration you can only scan from one side, versus a butt weld you can scan from both sides. If you scan from one side, say you use a 45, 45 down, bounce back 45, if a flaw happened to be - if the orientation of

the flaw happened to be parallel to the UT beam, you won't catch it. But on the other hand we looked at one applicant they performed UT for years since '94, and we looked at their results, and we found out they detected many cases of cracks, and they even cut out five, and verified four.

So what they are saying is, we might have missed a few, but we certainly detect quite a lot. The rationale here from the staff: is it perfect? No. But certainly it detects lots of flaws versus if you leaky tubes you miss everything. So I just wanted to elaborate a little more.

MR. TRAN: Yes, so just to say that volumetric that we are looking for is something other than - something more than just a surface, because the surface we determined --

MEMBER SHACK: That's what volumetric means, doesn't it?

MR. TRAN: That's what volumetric means.

NAME UNKNOWN: And what we see here this morning from the applicant, that certainly moved to the right direction.

MEMBER ARMIJO: Well, I hope destructive examination isn't the volumetric that's acceptable. This UT even if it's not perfect would be acceptable.

MR. PHAM: Yes, and we communicated that to the licensees, applicants as well, that we are not prescribing one particular - we understand the significance of the costs of doing something like that.

MEMBER ARMIJO: I even have my doubts about how much confidence you can have in a destructive examination if you don't cut the plane where the crack is, you can miss it. So it's a very tough - you got to know where the crack is to make sure that when you do your metallography you can cut right through the defect or miss it entirely. So I think UT seems to have, even though it's not perfect, seems to be as good as you can get.

MR. TRAN: Yes, the staff I believe completely formulate our acceptance criteria yet, as far as I know, and some of that will be revisited as far as the go-up date is my understanding.

MR. PHAM: The term, qualified, as is used in the and as interpreted in the GALL right now tends to kind of - the connotation from industry's perspective I think is that it has to be something like a PDI-qualified process. That is not what we were intending, and we are taking efforts to update that in the GALL.

CHAIR STETKAR: Okay. Bo, from our perspective, though, for a take away for future license renewal applications that come before our site committee, it sounds like we should be expecting to hear from the staff more emphasis on some type of volumetric examination, for example, than we have seen perhaps in past applications, and that perhaps we should be a bit sensitive to that. Is that a fair statement?

MR. HOLIAN: Yes.

MR. TRAN: Okay, any other questions? Okay, we can move to the next slide. The staff reviewed applicant's operating experience and identified a concern about the cumulative effect of more than 2,000 pits in the torus.

CHAIR STETKAR: But it would be good to talk about buried piping and tanks.

MR. TRAN: Okay, let me go back here. There have been a number of recent industry events involving leakage from buried and underground piping, where the causes have included coating damage during backfill piping, failures of fiber or glass piping, failure of buried piping and around piping penetrations, and failure of piping in trenches. Cooper's program is a new program which aim at

managing the effect of aging in piping in direct contact with soil. The programs covers incorporation of industry experience later during the period of extended operations, so the staff felt like we needed additional information to make our review. And the staff issue a late request for additional information in April so that we could gather information. So the staff will provide a flow chart of this overnight as the information comes in as part of the final SER documentation.

MR. PHAM: That was included in the May 4th letter that we just received.

MR. TRAN: Right.

CHAIR STETKAR: I had a question, and it may be just misunderstanding, my misunderstanding of the wording. In the staff's audit report there is a discussion about buried piping and I will read the statement that confused me: It said plant personnel indicate that internal linings or coatings are used all buried piping, and that all above ground piping is not internally coated. Operating experience reviewed indicates a significant number of failures of unlined piping. The proposed aging management program appears to be inconsistent with the program recommended by the GALL report in that some of the piping in use at the

plant is not coated as recommended. Is the cited operating experience in that auditing report Cooper plant specific experience, or is that just a general reference to industry operating experience from other sites? Because there are other references, and I thought we heard this morning, that said that the general experience from the Cooper piping is pretty good.

MR. TRAN: We have the reviewer to answer this for you.

MR. ALEX: Dave Alex from the staff. There are two aspects of some of these corrosion incidents: corrosion from the inside, corrosion from the outside. Corrosion from the inside of the pipe is covered by a number of AMPs. The buried piping program is not one of those. The open cycle cooling water program would be one of those. I suspect that what you are reading from is the audit report from the open cycle cooling water.

CHAIR STETKAR: It's actually service water integrity.

MR. ALEX: Okay, which is the open cycle cooling water equivalent from Cooper. My suspicion is that based on my listening to what you read is that there was a slight mix up in the words. If memory

serves correctly - and I did not review that program this morning, I reviewed the buried piping program this morning - if my memory serves me correctly, there were sections of the open cycle cooling water piping that were not internally coated.

CHAIR STETKAR: Let me stop you there. I will let you finish that, but I would like to repunch the - I'd like to punch a lot of people - I'd like to ask the applicant to respond to that, because I thought we heard this morning that all of the service water piping was both lined and coated.

CONSULTANT BARTON: Right.

MR. ALEX: And I am operating off of memory at the moment because I did not review this this morning. It's my suspicion that there were certain sections that weren't internally coated, that they were above ground so that they could be accessed more readily than the below ground sections, and that that comment in the audit report mainly serves to point out that there were certain sections that weren't strictly consistent with the GALL report.

CHAIR STETKAR: I guess I would like to follow up on two things. I just want to make sure that the reference to significant numbers of failures of unlined piping that that is for reference to

generic industry operating experience, and not something that the staff identified as a plant specific concern at Cooper, or is it a plant specific concern at Cooper.

MR. ALEX: It is more industry than --

MR. HOLIAN: This is Brian Holian. We asked a similar question on that during our prep sessions, and it is industry operating experience. Dave is up here also covering for us for staff that is not here. Dave was a license renewal reviewer, but not on Cooper. Since he has since transposed over, that's a good person to meet. He's over in the Division of Component Integrity responding to the agency's groundwater initiative and they action plan for that. So he's probably got about 10 plants bouncing around in his mind as answer to generic question.

Did you have a second item?

CHAIR STETKAR: Well, the first thing helps me a lot, because I just want to make sure that there isn't lurking staff concern with a Cooper specific issue. The other one was just the clarification from the applicant regarding the lining in the coating of their - I'll used the term, buried piping.

MR. LINER: This is Phil Liner for the applicant. For our service water system our buried pipe has an external coating and an internal coating. The internal coating has a couple of stages in it, but it is coated on the inside. Our above-ground piping that is contained within our buildings service water is not internally coated. It is carbon steel material.

CHAIR STETKAR: Thank you.

CONSULTANT BARTON: Wasn't there an issue about some insulation, that the coating on some stainless steel piping that they were taking credit for?

CHAIR STETKAR: I don't remember that one.

CONSULTANT BARTON: Okay.

MR. TRAN: Okay, can we go to the next slide.

The staff identified an open item related to the management of aging effect of the torus. The staff reviewed the applicant operating experience, and identified a concern about the cumulative effect of more than 2,000 pits in the torus. The staff noted some of the pit corrosion have reached bare steel. Also the apparent galvanic corrosions reached new

higher and unpredictable pitting corrosion rates.

The staff will review the information provided for closure of this item in the final SER.

MEMBER ARMIJO: I have to ask you, did you agree with the applicant's data that is represented here on pit depth as a function of years of operation, basically it's their figure - well, there is no page number, but it's their figure showing the mean depth and then also the 95 percent I guess, 95 percent - it's a mean plus two sigma line.

MR. TRAN: Yeah, we have a reviewer here.

MEMBER ARMIJO: Because the question I have is, on the page - their chart 35, they say the maximum torus pit depth was 92 mils, which is much larger than the two sigma maximum on this chart. So - and it's the deepest pit that is going to cause some grief. So how does that all come together and how does the staff interpret that?

MR. TRAN: We have the reviewer here.

MEMBER BONACA: We have the staff here, but I would say right now is, the information we've been in discussion with the applicant. We have recently received the information and we really haven't had the time to digest that. I can definitely say we can neither agree nor disagree.

(Simultaneous voices)

MR. SHEIK: I agree, we received this information a few days ago and we haven't looked at it in detail.

MR. PHAM: But one thing I could say in discussion with the applicant allow the information regarding the history, and the mean numbers and stuff like that did at least give us the cover - we are getting the information that we had been looking for basically. That was the essence of our concern was the cumulative effects of the pitting.

MEMBER ARMIJO: But is there some maximum pit depth that you would say hey, this torus is in trouble? I mean it seems like they have quite a bit of margin in total wall thickness, but is there some criteria that the staff is using?

MR. TRAN: Well, we do believe that the margin rate could be very uncertain, unpredictable. So we have to look at it very closely to see whether we could agree. We didn't have the time to provide it to you this morning.

MEMBER ARMIJO: Okay.

When this comes to full committee, will it be?

CHAIR STETKAR: We will talk about that.

MEMBER SIEBER: Well, I guess in my view there is a sort of a fallacy in measuring pit depth after a certain length of time and saying the average per year degradation is this much, because it's coated in the first place, and for the first number of years there are no pits, and so the rate that you would calculate over the lifetime is not representative of the rate that is going on now, and the data that they have shows that.

CONSULTANT BARTON: The rate should be increasing because of the coating being --

MEMBER SIEBER: The coating is in the area of exposure.

MEMBER ARMIJO: Right, but typically the pitting mechanism is kind of self limiting. It doesn't just run away and drill a hole through a steel wall.

MEMBER SIEBER: That is true. That is true, because the corrosion parts limit access. And I think there were only two instances I saw where they were below what one would call min wall, and if you look at the analysis of another plant where we spent a lot of time looking at this from an integrity and a collapse standpoint the vulnerability is pretty far away from this particular plant.

MR. PHAM: Yes, like Greg indicated, as far as current operation perspective, we don't have an issue with that right now. It's just for the future, and just the unpredictability of the corrosion rate is what we are concerned about. We will elaborate on that as part of the final SER.

MEMBER SIEBER: And I agree we need to have some opinion on that.

MR. TRAN: This slide covers typical items of interest for licensees. We show this slide at the time the application is submitted. And the latest Cooper sampling data in 2006 indicate that the low grade environment for concrete is non-existent.

CHAIR STETKAR: I noticed this information is provided from the 2006 sample. Is there any historical information regarding groundwater aggressiveness from 36 years worth of operating experience, or 15 or 20 years, to show that indeed these particular samples are representatives? Or could this just be after a very very heavy rain?

MR. TRAN: Yes, this is just a data point that we have in the application review. But we also noted that there was a commitment to sample groundwater at least once every five years. So this is a baseline at this point that we are looking at.

As far as any more information that we might have reviewed other than 2006 I have to review that to our staff.

CHAIR STETKAR: If I can ask the applicant did you have any other groundwater chemistry samples prior to 2006?

MR. AHRABLI: This is Rewza Ahrabli speaking for the applicant. We have data, original data, on the SAR. The water was nonaggressive. The pH level was above 5.5 of course, and the chloride very very low, I don't remember exactly what, but it was way below like 50 ppm, which is versus - for chloride is 500 ppm, and the sulfide like versus the 1,500 ppm threshold. So what - the SAR data we wanted to confirm that nothing had changed, so that's why we conducted the 2006, actually as a result of the license renewal. License renewal data shows up very low, so it hasn't changed much.

CHAIR STETKAR: Thank you.

MEMBER SIEBER: Did you collect the ground water from the well?

MEMBER ARMIJO: If that is the case you probably have tons of data from your sampling well.

PARTICIPANT: Bob Bialky speaking for the applicant, we would collect those samples from our

groundwater monitoring wells. We have several wells in the vicinity of the site structures that we can gather that from.

MR. TRAN: Okay, Section 4.2 of the SER covered reactor vessel neutron embrittlement analysis. This is another typical item of interest for license renewal. There were two reviews performed to evaluate neutron embrittlement as documented in the SER. The staff concluded that the active neutron embrittlement analysis meets the review criteria in the standard review plan. And as shown on the slide the calculated value shown meets our acceptance criteria.

The staff identified one componentry item for the metal fatigue analysis. The applicant agreed to address the views of 1995 NUREG --

MEMBER ABDEL-KHALIK: If you go back to a previous slide.

MR. TRAN: Sure.

MEMBER ABDEL-KHALIK: I think they indicated earlier today that they intend to submit an extended upgrade of the 20 percent, and that is planned for 2016. How would that impact this conclusion?

MR. TRAN: The fluence calculations will need to be relooked at. Do we have - Ganesh?

MR. THOMAS: Ken Thomas speaking for the applicant. As part of the integrated surveillance program whenever we make a change that could affect the accumulated fluence we have to reevaluate that, and we will be doing that for the 24-month cycles, and we will have to do that for power uprate as well. And we will look at that again.

MR. TRAN: We also have a reviewer here if you would want to make any comments?

MR. HOLIAN: It is part of the separate license amendment process.

MR. TRAN: Any questions?

Okay, all right, this is the slide that we just covered addressing the confirmatory item of the metal fatigue analysis. So basically we asked the applicant to come back to provide us a submittal.

MR. PHAM: This was the late breaking item as part of our peer review we noticed that applicant was used a value referencing an older version of a NUREG. The staff asked a question, the newer version, the new NUREG 6909 has more calculations of more realistic as opposed to a static concept. So we just asked confirmation from the applicant if they could provide us whether their calculations are still conservative or they are going

to need a new calculation. My understanding is they haven't made the calculations yet, but they have updated the commitment to do that.

CHAIR STETKAR: We have a little bit of extra time here, and I wanted to make sure that you got through what I thought would be a more detailed discussion about a couple of topics. Two areas in the fatigue monitoring program, applicant shows projected cumulative usage factors for the feedwater nozzles in the RHR return piping out over the 60-year life that are substantially above one. There were several questions about how those were calculated, and without going into fine structure detail about how they were calculated, they seem to project a potential failure of concern. I think my first question is, is there an area of concern for the feedwater nozzles even out into the beginning of the period of the extended operation, in other words, 2014, the environmentally corrected usage factor.

MR. YEE: This is On Yee from the staff. The applicants have a commitment to refine the analysis to include environmental effects or repair or replace the components that you are talking about, the feedwater nozzle, the RHR, and there is one other one.

CHAIR STETKAR: The other one was only

slightly --

MR. YEE: But for those three components they have a commitment to refine the analysis including environmental effects or to repair or replace the component. Two years prior to the PEO.

CONSULTANT BARTON: I thought there two out of three that were supposed to be greater than one. I should have written them down, but that's what I thought I remembered.

CHAIR STETKAR: One is a reactor vessel nozzle, the feedwater nozzle, RHR return line and core spray nozzle is the third one. In the core spray nozzle the 60-year projected was 1.5. So it was above one, but not substantially.

MEMBER SHACK: Not 10.7.

CHAIR STETKAR: Not 10.7 for example.

MR. HOLIAN: This is Brian Holian, Division of License Renewal. You know it's a good concern. It's a concern of the staff too. We have the 7103 inspection from the region still coming. The staff from headquarters will assist them even on -- we select certain topics, and this will clearly be one of them as we review and sample these calculations.

CHAIR STETKAR: Are you - I know there were quite a bit of discussions in the SER, a number

of questions and apparently a number of follow up discussions with the applicant regarding their estimates of the number of thermal cycles out over the 60-year period, and how those were derived from historical operating experience and extrapolated out.

Is the staff fairly confident that the estimates in terms of cycles that have been used in the projections are reasonable or on the conservative side of being reasonable?

MR. YEE: This is On Yee from the staff. The trends that they provided show based on operating experience and based on what operating practice that the transients have decreased in numbers. But regardless, using their fatigue monitoring program to track the number of actual cycles and take corrective actions before they reached the action limit.

CHAIR STETKAR: Okay.

MR. PHAM: The line of questioning was just to clarify where the data was coming from.

CHAIR STETKAR: And there seemed to be some questions about how they were counting cycles, and whether there were - I wasn't quite sure whether they were double counting cycles in some categories, or whether they were missing cycles because of where they were moving events around.

MR. PHAM: I think that the staff's line of questioning was addressing the same concerns.

MR. TRAN: We looked at what they provided as justification or explanation.

All right, our next slide is the conclusions slide. In conclusion the staff determined that pending closure of the open item and confirmatory items, the requirements of 10 CFR 54.29(a) have been met for the license renewal of Cooper Nuclear Station. Basically we were documenting all the late breaking information that we received from the applicant as part of our development and issuing of the final SER. As you will see.

MR. PHAM: Like I said, where we are right now I think we have received information for all the open items, and confirmatory items. So we don't have anything hanging out there.

CHAIR STETKAR: There could be follow up, additional follow up from the letters you just received recently.

MR. PHAM: Yes.

MR. TRAN: There might be, asking for some clarification. Any other questions?

CHAIR STETKAR: Thank you very much. And again, I personally was very pleased with the staff's

review of this. I thought it was quite thorough. I was really happy with how you dug into the plant specific operating experience, and it seemed to have been a very thorough job in that area.

I think what we will do now is, I would like to go around the table and see if any of the members have any additional questions either for the staff or the applicant, things that have come up. And then if there are no other questions, we'll have just a general close out, I want to ask the members a couple of other questions.

John, since you are a consultant, you get to ask the first questions.

CONSULTANT BARTON: Oh, good. I noticed that - the license expires in 2014. I looked at where the applicant is in all its programs, its aging management program, developments, one time inspections that need to be done before the current license expires, I don't see that they are well along with the amount of short time they have got left to complete all this. And I wonder, you have been looking at that, and that has been a concern, because I haven't seen that in any of your presentations. But that is something that I would be concerned about. There are an awful lot of programs that are still being worked

on and aren't even completed, and some may have to be done before that 2014, and I just wonder, worry about that a little bit.

MR. TRAN: We looked at that as part of the inspection directive, and there will be another inspection, 7003, to just look at the overall assessment with respect to that. Greg, do you want to say anything about that?

MR. PHAM: If I may, I think we clearly communicated that to the applicant, during the inspection and audit, as well. So Art might to be able to respond to that as well. But from our perspective we are taking it through the process. The assumption is that they are going --

CONSULTANT BARTON: They have to. So you are really looking at that and ensure yourself that that is going to happen before you hand them another license.

MR. PHAM: I think it is going to be a function also of how the applicant responds to getting themselves in gear for this.

MR. ZAREMBA: And this is Art Zaremba speaking on behalf of Cooper Station, we also recognize that the time frame that is left to fully implement all the programs and commitments, we have as

you heard our presentation today started on many of those. We have two basically, two refueling outages between now and the start of the PPL to get any of our refuel outage type work activities complete, and we have started planning those work items, the work scope, and we have dedicated resources, which got a schedule for many of the online program commitments, inspections, and activities to support that. So we are confident, and we will meet our commitments, prior to PEO, that need to be done in support of aging management programs.

MEMBER ARMIJO: If you had to repair or replace a feedwater nozzle because of fatigue, do you really have enough time or have you prepared for that contingency, if you can't analyze --

MR. ZAREMBA: Right now our priority has been to spend the engineering resources to get the analysis --

MEMBER ARMIJO: I would hope so.

MR. ZAREMBA: And it's not that we haven't started that at all. In fact we will be well ahead of that two-year commitment that you saw on updated analysis of things like that engineering area work. We are pretty much almost done with that now. That still doesn't leave us much time, you are

correct, if the outcome of that - but we are pretty confident we won't have to go there.

CONSULTANT BARTON: The only other comment I have, I want to congratulate the staff. I think they did a real good job of reviewing the application.

CHAIR STETKAR: Jack, any questions?

MEMBER SIEBER: No, I don't have any additional questions.

CHAIR STETKAR: We'll go back around. There are a couple of other things I want to ask the members. But I just want to make sure there weren't any other technical issues or questions that anyone had.

MEMBER RAY: No, I don't have anything.

CHAIR STETKAR: Sam.

MEMBER ARMIJO: No, no questions.

CHAIR STETKAR: Said.

MEMBER ABDEL-KHALIK: I think this thickener was just made by the applicant, the applicant is confident that they will not have to replace the feedwater nozzles. What is the basis of that confidence given the numbers that have been presented so far?

MR. THOMAS: Ken Thomas speaking for the

applicant. We have received the calculation from our vendor, and the preliminary results indicate that all those areas are going to be less than one. So that is why we have confidence, but we are still doing our final review and calculations.

MEMBER ABDEL-KHALIK: Okay.

CHAIR STETKAR: Okay, anything else?

Bill?

MEMBER SHACK: No.

CHAIR STETKAR: Mario?

MEMBER BONACA: No questions.

CHAIR STETKAR: Okay, good, I think the only thing else that I'd ask the subcommittee is, given the current status of the SER, and the fact that the staff is still reviewing items that have just come in over the past couple of weeks, given what we have heard today, I'd like to see if you feel that there might be a need for another subcommittee meeting, or whether you feel that the presentations to the full committee of the final SER after all the open items were closed would be sufficient. So the basic question is do you think we would need another subcommittee meeting to hear how the open items are closed out. Jack?

MEMBER SIEBER: Well, obviously it

depends on what the final resolution of the open items is.

CHAIR STETKAR: I'm just trying to figure in terms of scheduling.

MEMBER SIEBER: But where I think they are going to go, I don't see the need for an additional subcommittee meeting.

CHAIR STETKAR: Harold?

MEMBER RAY: I agree.

CHAIR STETKAR: Stan? Said? Good. That helps a little bit in terms of our scheduling internally and working with the staff to see where we might be headed on this. Anything else from anyone?

MEMBER BONACA: One thing, we don't plan to have a letter from the - an interim letter?

CHAIR STETKAR: At the current point I don't see what any interim letter could say. I think that from what we have heard today any of the potentially significant open items the staff is working on them, and I don't see anything that is an issue that would merit an interim letter from us.

MEMBER SIEBER: The only time you would need an interim letter is if we disagree with the staff resolution.

CHAIR STETKAR: Right, which is one of

the reasons why I asked about should we have another subcommittee meeting. I didn't' sense that there was --

MEMBER SIEBER: And I don't see that.

CHAIR STETKAR: I don't see a rift developing where we are either on one side or on the other side or in the middle some place.

MEMBER BONACA: I thought - I just asked the question, but I believe with only a letter, I think that there as a good application, and I think it was even a better SER, the SER was - one observation I would like to make in general was that I went and looked at the operating experience of the applicant. It was skimpy to say the least. For example on the buried pipe and tanks, there was barely a couple of paragraphs saying that these are in the program. Well, that is not operating experience. So I wish there was more there, and if you look at the SER, the communication back and forth, there is a lot of information which is important, because it's a big issue with the whole industry right now.

The other thing I would like to mention, you know, small bore piping is a significant change for the way we have looked at it in the past licensing rules. One time inspection has always been the issue.

We are now moving to a programmatic process, and I agree with that. I just wondered about the other plans we have looked at in the past.

CHAIR STETKAR: As I said earlier I think this application and this review seems to be sending a message to future applicants coming in, and it's something that I think we as a subcommittee, just to make sure that things are being done in a balanced manner.

MR. HOLIAN: This is Brian Holian, Director, if I might add to that. The question on previous plants, it is not lost on us on how we go back and do that. We do that through information notices, we do that on Part 50. I've told the industry I will come out and inspect you. Our 71.03s to verify that your Part 50 corrective action program is still learning from operating experience. Your license renewal aging management program, the 10 elements, are to continue to be informed by operating experience as you get into the extended period. So I do have a list of technical issues like this, Boral and the spent fuel pool we've noted that on a new plants. We've sent out license renewal ISGs on that interim staff guidance, to follow up on licensee's corrective action programs on these pieces. So that

was one item I wanted to kind of assure the ACRS and they come up in our quarterly NEI meetings also in looking back.

The other piece on operating experience in applications, I don't know if I have a great handle historically on how much has been in there. But the note has been put out to them not only on applications from here on out, but especially if you are looking even in the future still that that is such a key component to have there. I do grant though that when we go the audits and the inspections, they do have quite a bit of material there in binders, and for our inspectors and auditors to go through. And we try to pick up some of that in the audit report. I still think we are not as comprehensive as we have been. But over the last couple of years, I think you have seen them in the SERs and you have commented, we have been trying to put it in there. But I agree, to get it in the application is a better push also.

MEMBER BONACA: Yes, I just wanted to make the observation because in particular because of the buried piping there is a lot of information in the SER or the inspection, but if you look at the starting point, which was the application itself, there is again, a parallel.

MR. HOLIAN: Yes, agreed totally. Right now we have for the 13 plants you will see RAIs going out on buried piping to all plants. So Coopers is one to beef up that operating experience, site specific, and what are you doing evaluating the industry experience. We have one that is in house now that has buried pipe, significant corrosion on an aux feedwater buried pipe system. So that type of experience we want to make sure the industry is seeing it, and they are, it's getting Commission-level attention as you are aware.

CHAIR STETKAR: Okay? If nothing else, again I'd like to thank the staff. I'd like to thank the applicant. All very very good presentations, certainly well supported. And with that we will adjourn.

(Whereupon at 11:44 a.m. the proceeding in the above-entitled matter was adjourned.)

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United States Nuclear Regulatory Commission

Protecting People and the Environment

Advisory Committee on Reactor Safeguards (ACRS)
License Renewal Subcommittee
Cooper Nuclear Station (CNS)

Safety Evaluation Report (SER)

May 5, 2010

Tam Tran, Project Manager
Office of Nuclear Reactor Regulation

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Presentation Outline

- Overview of CNS license renewal review
- License renewal Audit and Inspection
- SER Section 2: Scoping and Screening review results
- SER Section 3: Aging Management review results
- SER Section 4: Time-Limited Aging Analyses (TLAAs)

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Overview (LRA)

- License Renewal Application (LRA) submitted in September 2008
  - CNS located in Nemaha county, Nebraska
  - GE BWR Mark I Design
  - 2419 megawatt thermal, 830 megawatt electric
  - Facility Operating License No. DPR-46 expires January 18, 2014

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Overview (SER)

- Safety Evaluation Report (SER) with Open Items issued on April 6, 2010
  - 4 Open Items (OIs):

    OI 2.3.4.2-1 - scoping of condensate storage tank

    OI 3.0.3.1-1 - management of small bore piping socket welds

    OI 3.0.3.1-2 - management of buried piping and tanks

    OI 3.0.3.2-1 - management of pitting corrosion in the torus
  - 1 Confirmatory Item (CI):

    CI 4.3.3.2-1 - use of NUREG/CR 6335 vs. 6909 for metal fatigue analyses of alloy 600 component

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Audits and Inspection

- Aging Management Program (AMP) Audit

  April 20 – 24, 2009
- Scoping and Screening Methodology Audit

  May 4 – 8, 2009
- Region IV Inspection (Scoping and Screening & AMP)

  July 27 – 31, 2009 & August 10 – 14, 2009

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Cooper Nuclear Station License Renewal Inspection

Greg Pick

Region IV Inspection Team Leader

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Regional Inspection

- Regions IV, III & I for 2 weeks
- Scoping & Screen
- Aging Management Programs

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Inspection Results

- Scoping of nonsafety-related systems
- Aging Management Programs
- Torus

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BWR 4 Mark I Containment

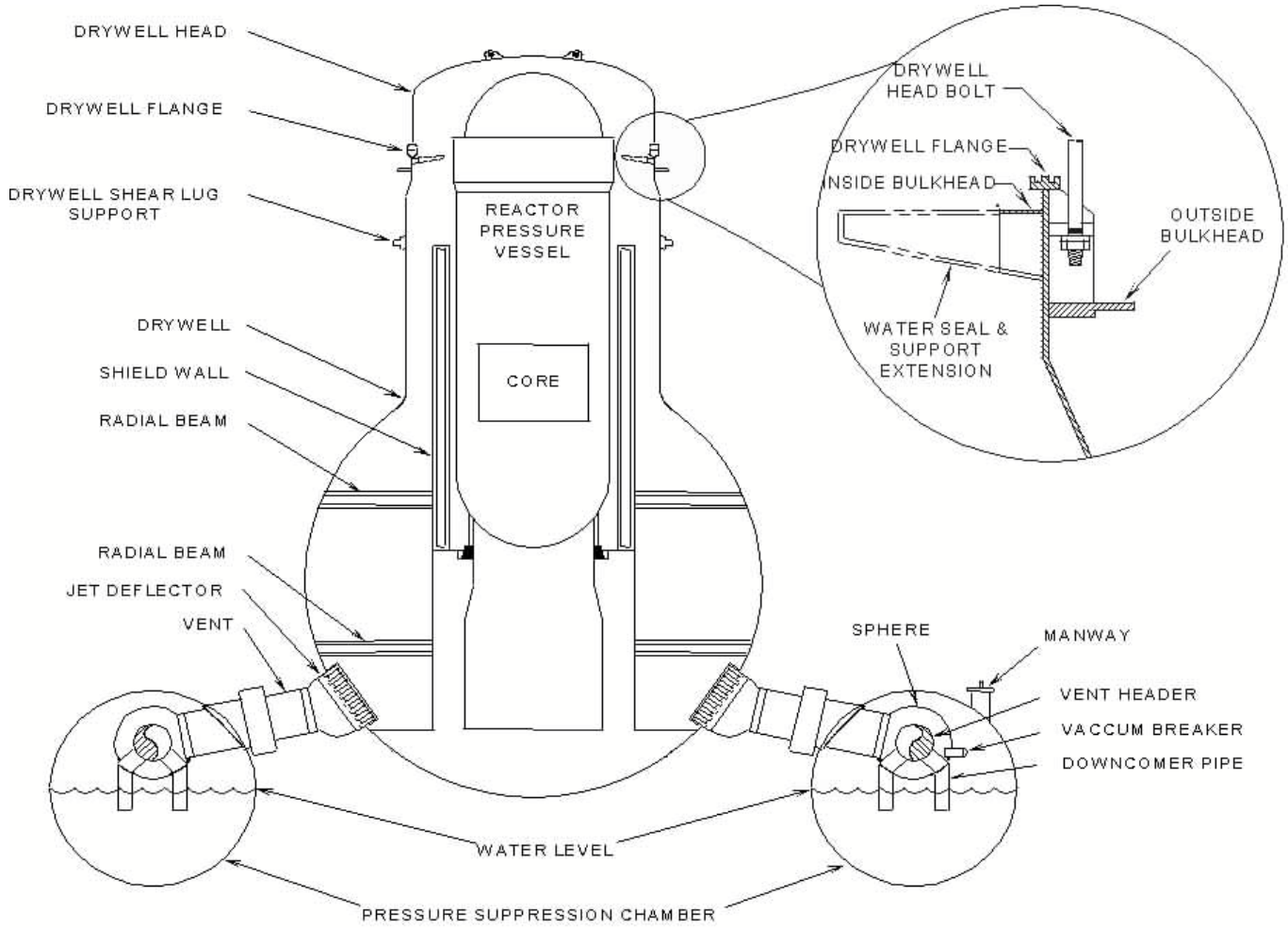

Figure 4.1-1 Primary Containment System

1106

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Bay 3 Pit Group

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Bay 9 Grid

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Downcomer Interior

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Ring Girder

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Current Performance

- Licensee Response Column
- Findings – Green
- Performance Indicators - Green

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Inspection Conclusions

Overall

- Scoping of non-safety SSCs and application of the AMPs to those SSCs were acceptable
- Reasonable assurance exists that aging effects will be managed and intended functions maintained

Torus

- Currently meets the ASME code for structural integrity; however, concerns exist related to maintaining design control to ensure containment integrity
- URI and open item will address these concerns

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SER Section 2: Structures and Components Subject to Aging Management Review

Section 2.1 Scoping and Screening Methodology

- Staff concludes that the applicant's methodology is consistent with the requirements of 10 CFR 54.4 and 54.21

Section 2.2 Plant-Level Scoping Results

- Staff concludes that the applicant has appropriately identified the systems and structures in accordance with 10 CFR 54.4

Section 2.3 Scoping and Screening Results: Mechanical System

- OI 2.3.4.2-1 - scoping of condensate storage tank

Section 2.4 & 2.5 Scoping and Screening Results: Structures and EI&C System

- Staff concludes that the applicant has appropriately identified the structures and EI&C components in accordance with 10 CFR 54.4(a), and those subject to an AMR in accordance with 10 CFR 54.21(a)(1)

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Section 2.3.4.2 Steam and Power Conversion Systems In-Scope for 10 CFR 54.4(a)(2)

OI 2.3.4.2-1:

- LRA did not include Condensate Storage Tank (CST) 1A and flow path within scope for license renewal
- Staff's position is that CST 1A should be in scope, in accordance with 10 CFR 54.4(a)(2), because it is a viable and allowable source of coolant for Emergency Core Cooling System (ECCS) operation during shutdown

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SER Section 3: Aging Management Review Results

Section 3.0.3 40 Aging Management Programs (AMPs) evaluated in the SER, consistent with GALL report

	Plant specific	Consistent with GALL	With exception	With enhancement	With exception & enhancement
Existing (29)	3	6	6	9	5
New (11)	1	9	1	NA	NA

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Section 3.0.3.1.11 One-Time Inspection, Small Bore Piping Program

OI 3.0.3.1-1:

- CNS proposed to use visual (VT-2) examination in accordance with ASME Code Section XI for socket welds
- Given previous operating experience (OE) of socket weld failures at CNS, staff determined that periodic volumetric examinations would be consistent with GALL AMP XI.M35

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Section 3.0.3.1.2 Buried Piping and Tanks Inspection Program

OI 3.0.3.1.2-1:

- Staff requested late RAI B.1.3-3 on April 13, 2010, regarding buried and underground piping at CNS
- Given recent industry OE related to leaks from buried and underground piping, staff is interested in efforts to incorporate such OE into aging management program at CNS

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Section 3.0.3.2.6 Containment Inservice Inspection Program

OI 3.0.3.2-1:

- Staff questioned CNS's management of pitting corrosion in the torus for long term consideration (period of extended operation or PEO) and preventive measures (e.g., recoating)
- Staff has concerns about the cumulative effect of over 2000 pits that may affect containment integrity during PEO

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Section 3.5 Aging Management of In-Scope Inaccessible Concrete (below grade)

Commitment: sample groundwater at least once every 5 years during the period of extended operation

	Acceptance Criteria	CNS (2006)	
		min	max
pH	>5.5	7.0	8.0
Chlorides	<500 ppm	17 ppm	24 ppm
Sulfates	<1500 ppm	33 ppm	82 ppm

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SER Section 4: Time-Limited Aging Analyses

Section 4.2 Reactor Vessel Neutron Embrittlement Analyses

Upper Shelf Energy (USE) Decrease

Reactor vessel limiting material	**Fluence**	**Unirradiated USE**	**Predicted USE Decrease (RG 1.99, Rev. 2)**	**54 EFPY Projected USE**	**EOL USE Acceptance Criteria**
Lower Shell axial weld, ID 2-233-B	9.96 x10^{17} n/cm^2	69 ft-lb	24 %	52 ft-lb	**> 50 ft-lb**

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Section 4.3 Metal Fatigue Analyses

CI 4.3.3.2-1

- Staff requested confirmation regarding use of 1995 NUREG/CR as opposed to 2007 NUREG/CR, for calculating the environmental correction factor for nickel alloy components:
  - NUREG/CR-6335 “Fatigue Strain-Life Behavior of Carbon and Low-Alloy Steels, Austenitic Stainless Steels, and Alloy 600 in LWR Environments” (1995)
  - NUREG/CR-6909 “Effect of LWR Coolant Environments on the Fatigue Life of Reactor Materials” (2007)
- Staff’s position is that either the 2007 NUREG/CR should be used for nickel alloy components, or demonstrate that the use of the 1995 NUREG/CR is conservative

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Conclusion

On the basis of its review, the staff determines that, pending resolution of the open and confirmatory items, the requirements of 10 CFR 54.29(a) have been met for the license renewal of Cooper Nuclear Station

Cooper Nuclear Station

Cooper Nuclear Station
Personnel in Attendance

Art Zaremba	Director, Nuclear Safety Assurance
Dan Buman	Director, Engineering
Dave Bremer	Project Manager, License Renewal
Todd Hottovy	Manager, Engineering Support
Roman Estrada	Manager, Design Engineering
Brian O'Grady	Site Vice President and Chief Nuclear Officer
Ron Asche	NPPD President and Chief Executive Officer

Technical Staff and Project Support Personnel

Agenda

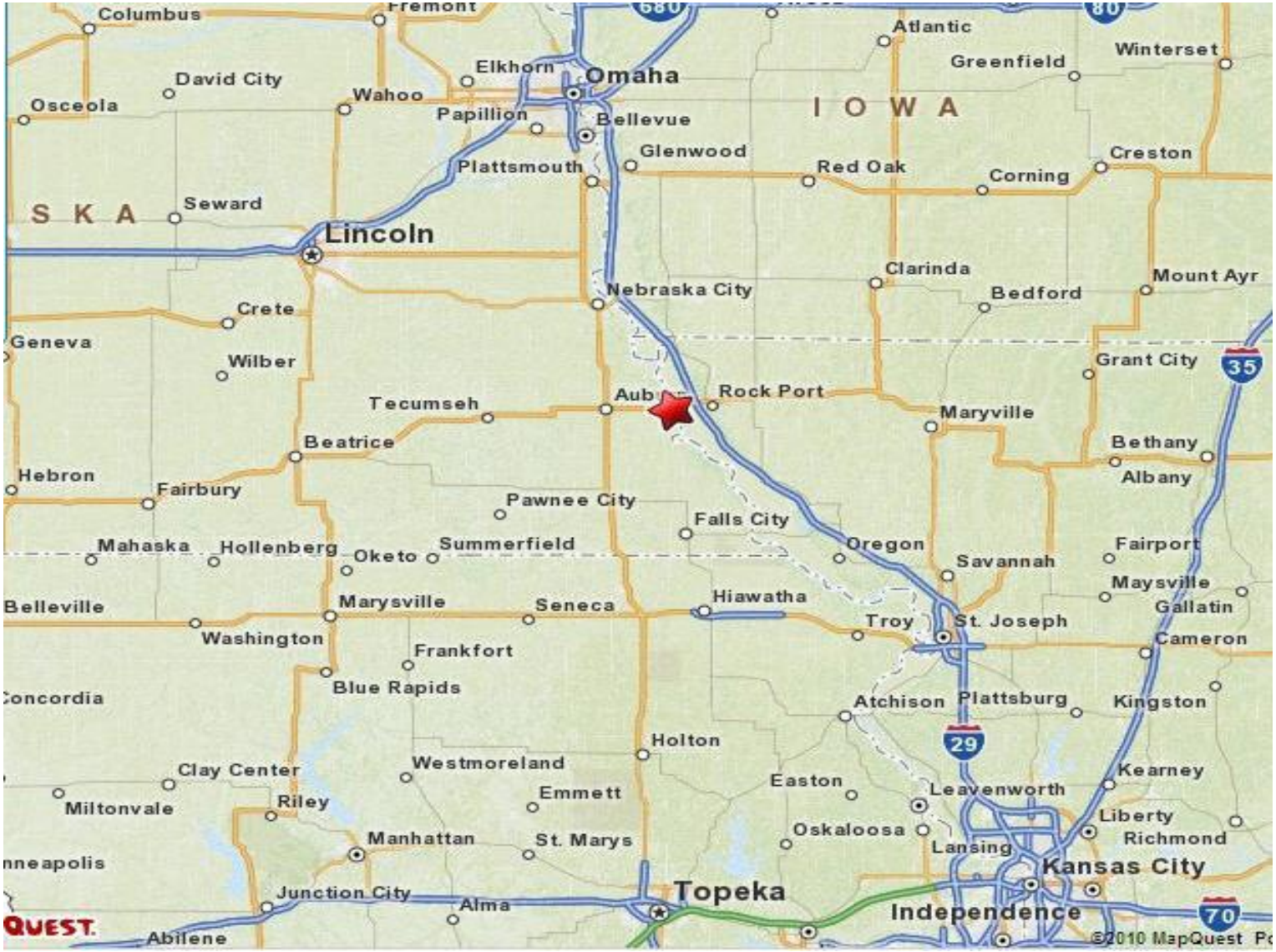
- Background
  - Site Description
  - Current Status
- Operating History/Experience
  - Licensing History
  - Major Improvements
- LRA Scoping
- Application of GALL (AMR/AMP/TLAA)
- Commitment Process
  - Implementation
- Technical Items of Interest
  - SER Open Items
- Concluding Remarks

Background

Site Description

- General Electric (NSSS), Burns & Roe (A/E)
- Westinghouse turbine and generator
- BWR-4, Mark-I Containment
- 2419 MW thermal power, 830 MWe
- Once-through cooling from Missouri River
- Staff complement: approximately 725

Background


Columbus
Fremont
Elkhorn
Omaha
Atlantic
Winterset
Greenfield
David City
Wahoo
Osceola
Papillion
Bellevue
I O W A
Glenwood
Creston
Plattsmouth
Red Oak
Corning
Seward
Lincoln
Clarinda
Mount Ayr
Nebraska City
Bedford
Crete
Geneva
Wilber
Grant City
35
Tecumseh
Rock Port
Maryville
Beatrice
Bethany
Albany
Hebron
Fairbury
Pawnee City
Falls City
Mahaska
Hollenberg
Oketo
Summerfield
Oregon
Fairport
Savannah
Maysville
Belleville
Marysville
Seneca
Hiawatha
Gallatin
Troy
St. Joseph
Washington
Cameron
Frankfort
Blue Rapids
Concordia
Atchison
Plattsburg
Kingston
29
Holton
Westmoreland
Clay Center
Easton
Kearney
Emmett
Leavenworth
Miltonvale
Riley
Liberty
Oskaloosa
Manhattan
St. Marys
Richmond
Lansing
Kansas City
Junction City
Topeka
Alma
Independence
70
Abilene
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Background

Current Status

- Start up on November 5, 2009 from RFO25 to begin Operating Cycle 26
- Current plant status
- Next refuel outage March 2011

Operating History/Experience

Plant History

• Construction permit	June 1968
• Operating license	January 18, 1974
• Commercial operation	July 1974
• Improved Technical Specifications	July 1998
• Measurement Uncertainty Recapture Power Uprate 1.6% (38 MWt)	June 2008
• Operating License expires	January 18, 2014

Operating History/Experience

Major Improvements

- Containment Piping Replacement
- ECCS Suction Strainer Replacement
- Noble Metals Application and Optimum Water Chemistry
- Service Water Pipe Replacement
- Intake Structure Improvement
- Feedwater Heater Replacement
- Low Pressure Turbine Replacement
- Main Generator Stator and Rotor Replacement
- Digital Control Upgrades
- Large Motor and Pump Replacements

License Renewal Application (LRA) Scoping

Scoping per 10 CFR 54.4(a)

- Scoping followed guidance of NEI 95-10 “Industry Guideline for Implementing the Requirements of 10 CFR Part 54 –The License Renewal Rule” Rev 6
- System scoping based on intended safety functions
- Conservative approach applied to electrical systems and EIC
- (a)(2) Scoping evaluated for both direct and indirect effects on safety-related components
- Spatial mapping of safety-related systems in proximity of nonsafety-related systems
- One Safety Evaluation Report (SER) open item regarding Condensate Storage Tank 1A
- In-scope system components identified and screened

Application of GALL (AMR/AMP/TLAA)

Aging Management Review (AMR)

- AMR conducted per guideline based on NEI 95-10 and industry guidance documents
- AMR reports and operating experience review developed concurrently
  - 25 Mechanical
  - 4 Structural
  - 1 Electrical
- AMR results achieved good consistency with the Generic Aging Lessons Learned (GALL) report

Application of GALL (AMR/AMP/TLAA)

Aging Management Programs (AMP)

- 40 AMPs
  - 29 existing programs are credited for license renewal
  - 11 new programs
- GALL Consistency
  - 24 programs are consistent or will be enhanced to be consistent with GALL
  - 12 programs with one or more exceptions to GALL
  - 4 plant-specific programs

Application of GALL (AMR/AMP/TLAA)

Time-Limited Aging Analyses (TLAA)

- Reactor vessel neutron embrittlement
- Metal fatigue
- Environmental qualification of electrical equipment
- Metal containment and penetrations fatigue
- Core plate plugs

Commitment Process

- License renewal commitments
  - 35 license renewal commitments
- License renewal implementation is in progress
- Participate in Nuclear Energy Institute - License Renewal Implementation Working Group
- Integrating license renewal programs with industry initiatives
  - Buried Piping Initiative
  - Inaccessible Electrical Cable Initiative

Technical Items of Interest

SER Open Items

- OI 2.3.4.2-1 Steam and Power Conversion Systems In-Scope for 10 CFR 54.4(a)(2)
- OI 3.0.3.1-1 One-Time Inspection, Small Bore Piping Program
- OI 3.0.3.1.2-1 Buried Piping and Tanks Inspection
- OI 3.0.3.2-1 Containment Inservice Inspection Program

Open Item 2.3.4.2-1

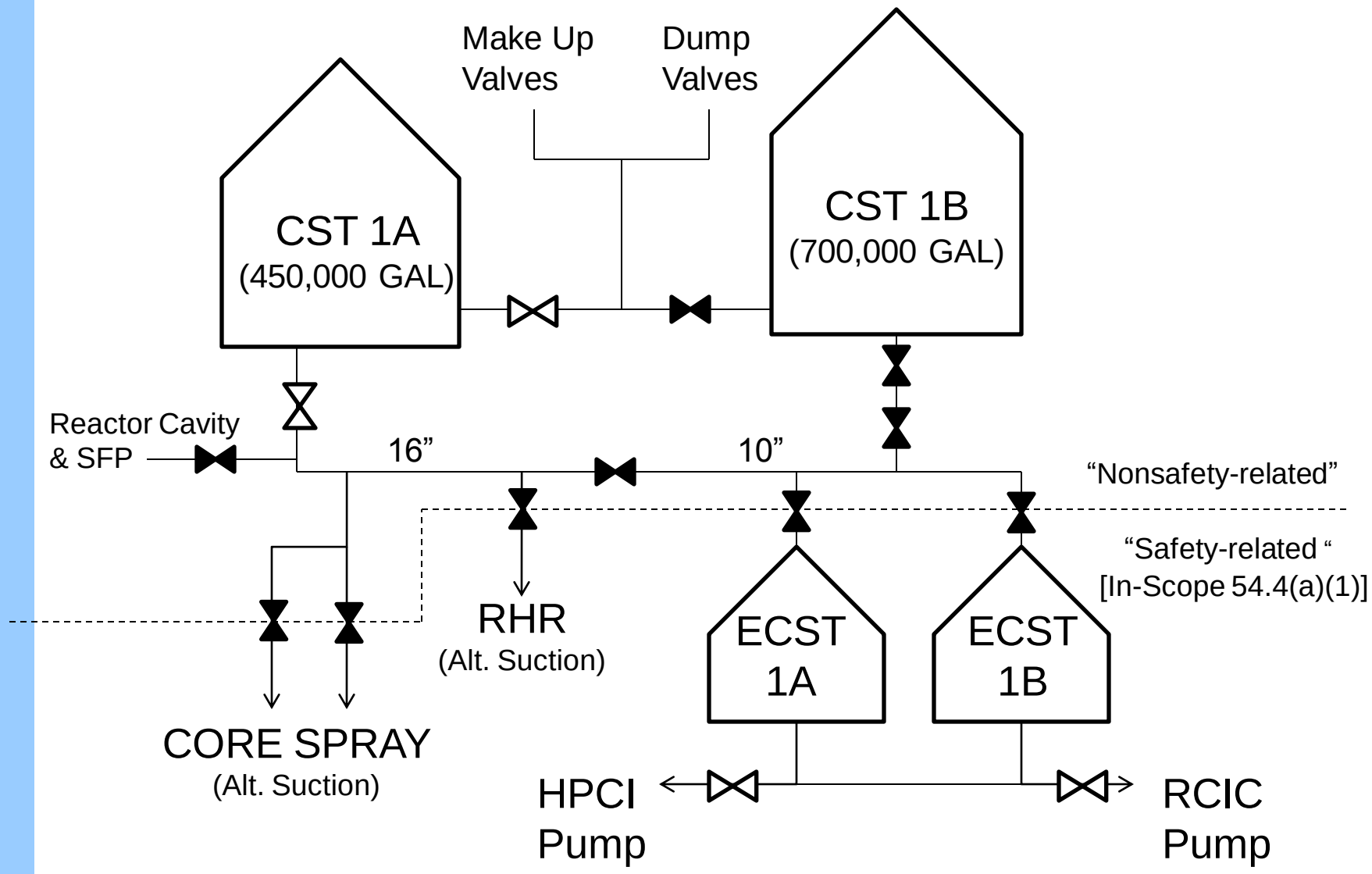
Steam and Power Conversion Systems In-Scope for 10 CFR 54.4(a)(2)

- Background
  - Condensate storage tank (CST) 1A and flow path not included within initial scoping for license renewal

    NOTE: Safety-related emergency condensate storage tanks (ECST 1A & 1B) were always included under 10 CFR 54.4(a)(1)

- Resolution
  - Station has included CST 1A and associated piping within the scope of license renewal and subject to aging management review

Condensate Storage and Transfer System



Open Item 3.0.3.1-1

One-Time Inspection, Small Bore Piping Program

- Background
  - LRA included the GALL one-time inspection of small bore socket welds versus a periodic inspection AMP and did not provide for socket weld volumetric exams
  - Based on industry socket weld operating experience, the staff maintained volumetric exams were appropriate
  - In light of CNS experience with socket weld cracking, the staff maintained a periodic inspection AMP was appropriate

- Resolution
  - CNS credited destructive examination of 12 socket welds and will perform periodic volumetric exams of a sample of socket welded connections during the PEO

Open Item 3.0.3.1-1

One-Time Inspection, Small Bore Piping Program

- Plant History
  - Three Class 1 and one Class 2 small bore piping socket welds found cracked
  - RHR-MOV-27A caused significant flow induced vibrations
  - Design deficiency resulted in modifications to valve trim and additional supports
  - Follow-up vibration monitoring confirmed resolution
  - Twelve additional welds examined (6 - Div A & 6 - Div B)
    - No additional cracks or other aging mechanisms

Open Item 3.0.3.1-1

One-Time Inspection, Small Bore Piping Program

- Summary:
  - Examine three Class 1 small bore piping socket weld connections during March 2011 outage using a volumetric technique
  - Station will include periodic examination of at least three Class 1 socket welds in each 10-yr ISI interval during the period of extended operation

Open Item 3.0.3.1.2-1

Buried Piping and Tanks Inspection

- Background
  - NRC Staff had requested information regarding changes to the Buried Piping and Tanks Inspection Program that CNS is developing in response to recent industry events involving leakage from buried or underground piping

Time Frame	LRA (GALL) AMP	Enhanced AMP
Prior to PEO	At least one inspection	At least six inspections prior to PEO
First 10 years of PEO	At least one inspection	Periodic inspections based on risk ranking of systems within the scope of license renewal
Remainder of PEO	None	

Open Item 3.0.3.1.2-1

Buried Piping and Tanks Inspection

- CNS is developing a Buried Piping and Tanks (BP&T) Inspection Program that is based on industry initiative
  - Industry Buried Piping Integrity Initiative
    - NEI 09-14 Rev. 0, “Guideline for the Management of Buried Piping Integrity” (January 2010)
- Based on OE, the CNS BP&T Program includes both buried and underground piping
- CNS BP&T Program will include ranking process with highest focus on safety-related and radioactive process fluids

Open Item 3.0.3.1.2-1

Buried Piping and Tanks Inspection

- Industry Program Elements and Milestones
  - Procedures and Oversight - June 30, 2010
  - Risk Ranking - December 31, 2010
  - Inspection Plan - June 30, 2011
  - Plan Implementation - start by June 30, 2012
  - Asset Management Plan - December 31, 2013
- Completed Inspections
  - Service water buried piping
  - Buried diesel generator fuel oil piping & tanks
  - Results indicated piping and tanks were in good condition

Open Item 3.0.3.1.2-1

Buried Piping and Tanks Inspection

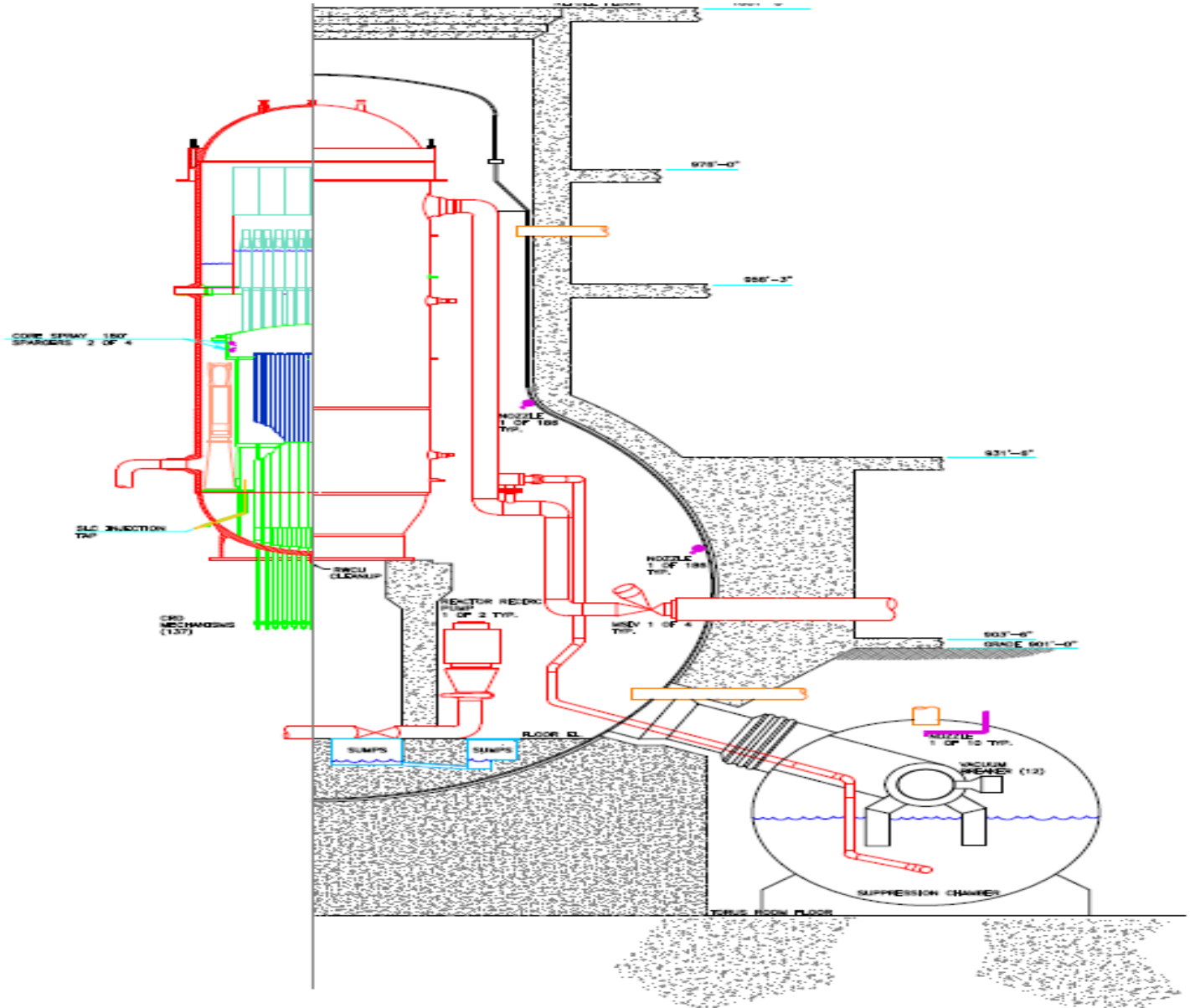
- Cathodic protection assessment completed and system upgrades beginning in 2010
- CNS is inspecting additional piping prior to the end of 2010
- Proposed Resolution
  - Develop and implement BP&T Program per industry initiative that includes both buried and underground piping
  - Prior to PEO, inspect high risk buried tanks and at least one segment of high risk buried/underground piping for each safety-related system that is in scope for license renewal. This will include service water, diesel fuel oil, high pressure coolant injection, and standby gas treatment piping.
  - Regardless of ranking, inspect piping associated with fire protection and condensate systems which are in scope

Open Item 3.0.3.2-1

Containment Inservice Inspection Program

Applicant has not demonstrated that the effects of the torus degradation will be adequately managed so the intended function will be maintained for the period of extended operation in accordance with 10 CFR 54.21(a)(3)

Torus Location



Inspection Program

Current Inspection Program Background

- Inspections developed in accordance with ASME Code, Section XI, Subsection IWE (GALL XI.S1)
- ASME Code based inspections started in 2001 (Mid-cycle outage prior to RE20) and were set up to be performed on 2 cycle frequency (every 3 years) based on observed pitting corrosion in the submerged section of the torus
- Next inspection scheduled for March 2011 (RE26)

Bay 9 Observation Area

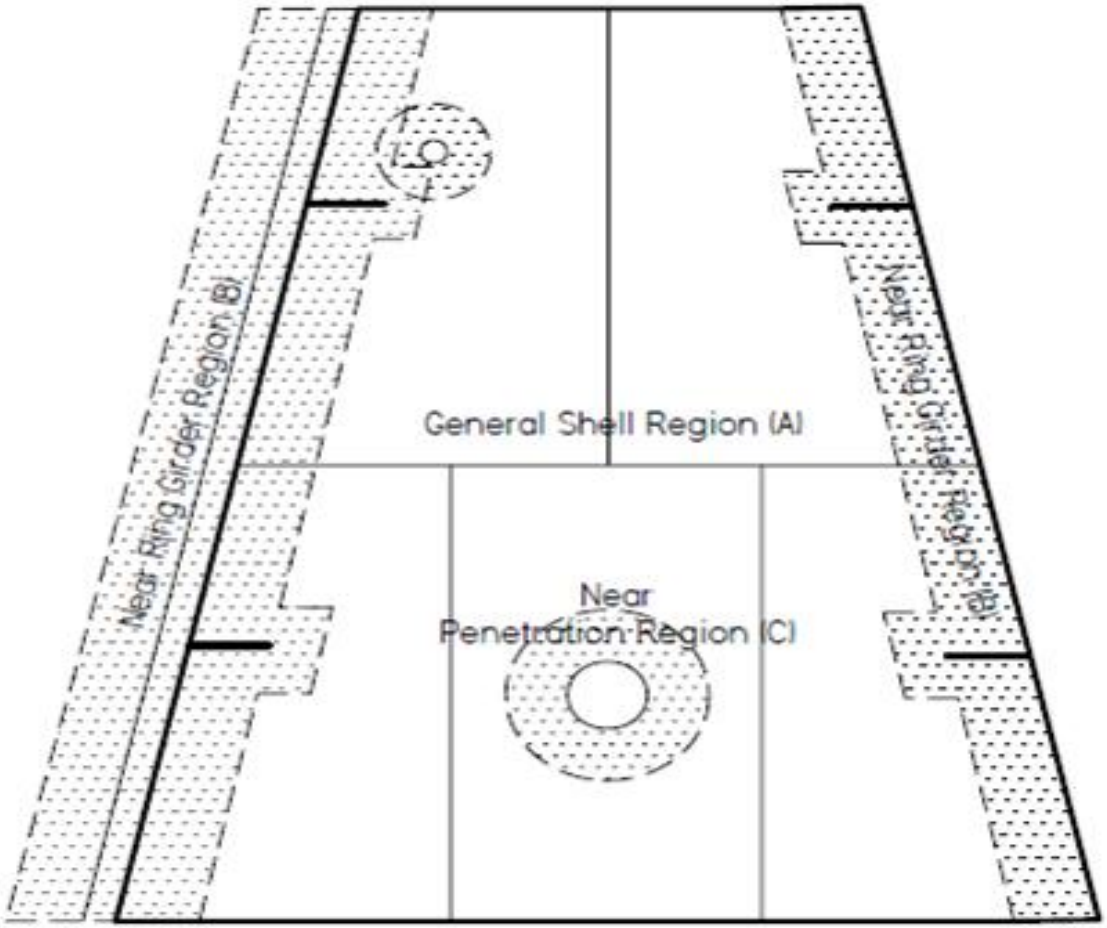
Torus Pit


15:06:10
04/20/08
S MORNEAU
LEVEL II
COOPER STATION
BAY 3 INSPECTION

Torus Pit Repair

Torus Pit Repair

Inspection Zones



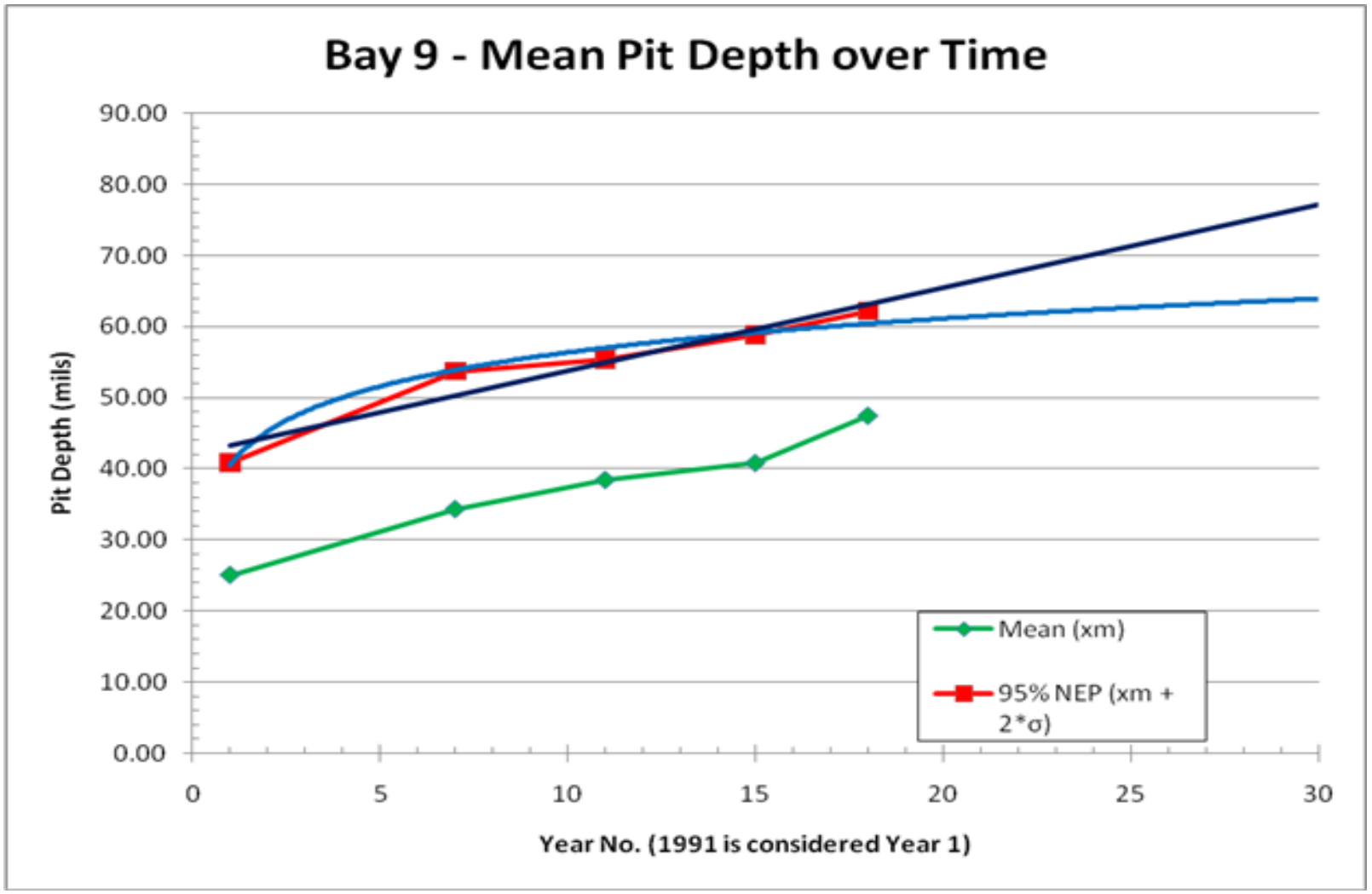
Inspection Criteria

Region Classification	Pit Type	Pit Depth	Coating Repair Required (yes/no)
Near Penetration	Shallow	0 to <30 mil	Yes
	Deep	≥ 30 mil	Yes
Near Ring Girder	Noted	< 50 mil	No
	Shallow	≥ 50 mil < 90 mil	Yes
	Deep	≥ 90 mil	Yes
General Shell	Noted	< 90 mil	No
	Shallow	≥ 90 mil < 150 mil	Yes
	Deep	≥ 150 mil	Yes

Torus Recoating History

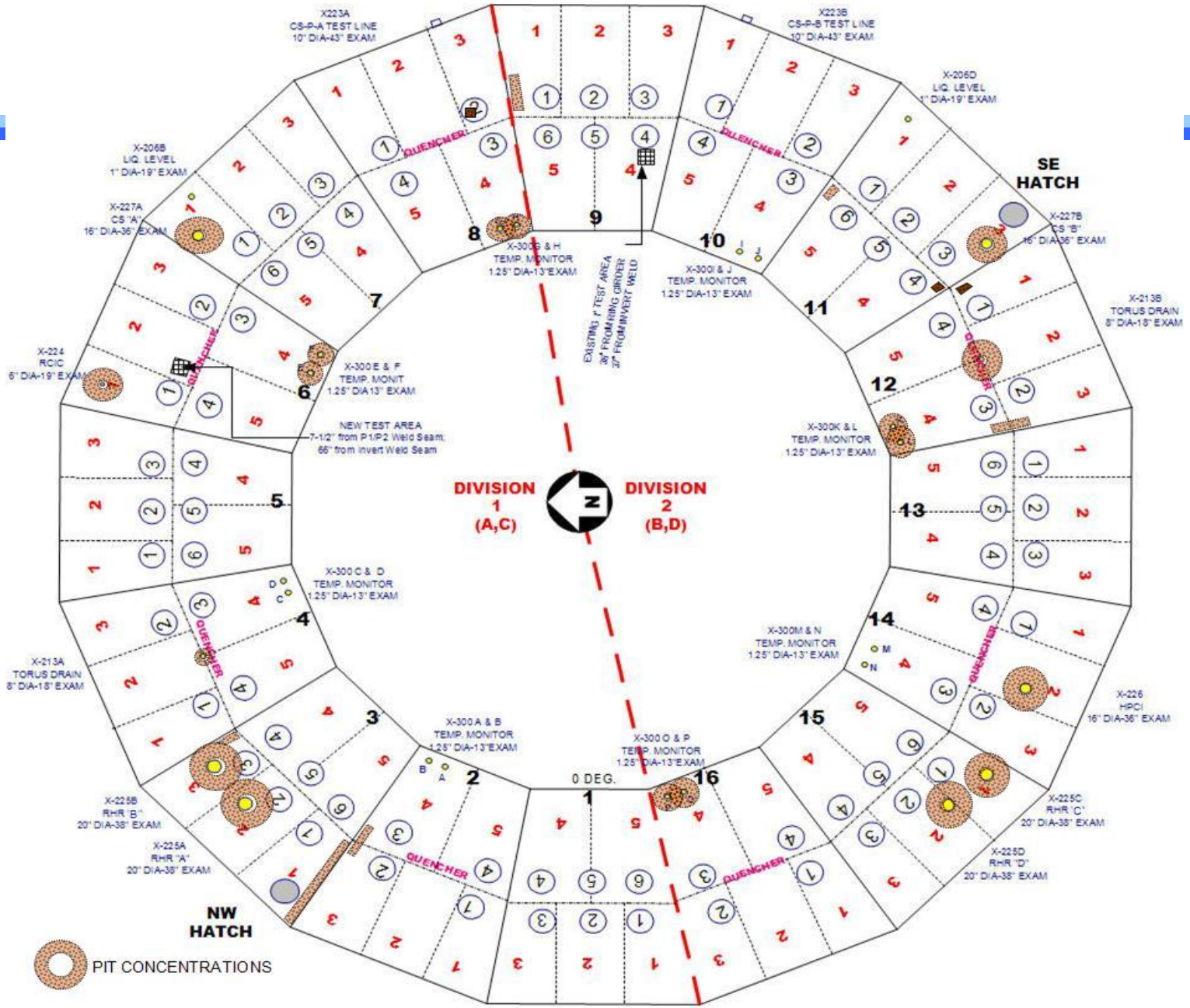
	1991	1993	1997	2001	2005	2008	Total
Number of pits recoated	151	105	1454	883	607	600	3800
Total Coated Area (ft^2)	1.6	1.1	40.0	77.5	12.7	12.1	145.0
Percentage of Wetted Surface Area	0.01%	0.01%	0.31%	0.60%	0.10%	0.09%	1.13%
Coverage Area Inspected	4 bays only	100% wetted area					

Torus Pitting Depth Rate



Torus Health

- Inspections since the implementation of the ASME XI inspection program have identified 2,090 pits that were recoated since 2001
  - Maximum torus pit depth was 92 mil
  - These pits were evaluated as acceptable in accordance with ASME IWE-3511.3


X223A
CS-P-A TEST LINE
10" DIA-43" EXAM
X223B
CS-P-B TEST LINE
10" DIA-43" EXAM
X-206D
LIQ. LEVEL
1" DIA-19" EXAM
SE
HATCH
X-206B
LIQ. LEVEL
1" DIA-19" EXAM
X-227A
CS "A"
16" DIA-36" EXAM
X-227B
CS "B"
16" DIA-36" EXAM
X-213B
TORUS DRAIN
8" DIA-18" EXAM
X-224
RCIC
6" DIA-19" EXAM
X-213A
TORUS DRAIN
8" DIA-18" EXAM
X-226
HPCI
16" DIA-36" EXAM
X-225B
RHR "B"
20" DIA-38" EXAM
X-225C
RHR "C"
20" DIA-38" EXAM
X-225A
RHR "A"
20" DIA-38" EXAM
X-225D
RHR "D"
20" DIA-38" EXAM
NW
HATCH
QUENCHER
X-300G & H
TEMP. MONITOR
1.25" DIA-13" EXAM
X-300I & J
TEMP. MONITOR
1.25" DIA-13" EXAM
X-300E & F
TEMP. MONIT
1.25" DIA13" EXAM
X-300K & L
TEMP. MONITOR
1.25" DIA-13" EXAM
X-300C & D
TEMP. MONITOR
1.25" DIA-13" EXAM
X-300M & N
TEMP. MONITOR
1.25" DIA-13" EXAM
X-300A & B
TEMP. MONITOR
1.25" DIA-13" EXAM
X-300O & P
TEMP. MONITOR
1.25" DIA-13" EXAM
EXISTING 7' TEST AREA
36" FROM RING GIRDER
37" FROM INVERT WELD
NEW TEST AREA
7-1/2" from P1/P2 Weld Seam;
66" from Invert Weld Seam
DIVISION
1
(A,C)
DIVISION
2
(B,D)
N
0 DEG.
PIT CONCENTRATIONS

Deep Pit Results

	2001		2005		2008	
	Near Penetration	Near Ring Girder	Near Penetration	Near Ring Girder	Near Penetration	Near Ring Girder
Total Deep Pits	77	3	1	0	25	1
Min Pit Depth	0.030”	0.052”	N/A	N/A	0.030”	N/A
Max Pit Depth	0.052”	0.062”	0.032”	N/A	0.059”	0.092”
Average Pit Depth	0.038”	0.057”	N/A	N/A	0.043”	N/A

Summary

- Torus health is acceptable per CNS Program in accordance with ASME XI inspection process, which has been effective in managing the effects of aging of the torus shell and its structural integrity
- Analysis supports torus design margin through 2020
- CNS will increase inspection and sludge removal of wetted portion of torus to every refueling outage until recoat
- CNS to perform a recoating of the wetted portion of torus within three years after entering the PEO

Closing Remarks