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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

September 6, 2007

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

545th MEETING

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THURSDAY,

SEPTEMBER 6, 2007

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The meeting was convened in Room T-2B3 of Two White Flint North, 11545 Rockville Pike, Rockville, Maryland, at 8:30 a.m., Dr. William J. Shack, Chairman, presiding.

MEMBERS PRESENT:

WILLIAM J. SHACK	Chairman
MARIO V. BONACA	Vice Chairman
SAID ABDEL-KHALIK	ACRS Member-At-Large
GEORGE E. APOSTOLAKIS	ACRS Member
J. SAM ARMIJO	ACRS Member
MICHAEL CORRADINI	ACRS Member
JOHN STETKAR	ACRS Member
OTTO L. MAYNARD	ACRS Member
DANA A. POWERS	ACRS Member
GRAHAM B. WALLIS	ACRS Member

NRC STAFF PRESENT:

JAMES DAVIS

PERRY BUCKBERG

P.T. KUO

LOUISE LUND

GLENN MEYER

THERON BROWN

KIM GREEN

AMBROSE LOIS

MARTY STUTZKE

LYNN MROWCA

MARK RUBEN

HOSSEIN HAMZI

DAVID FISCHER

RONALDO JENKINS

DONNIE HARRISON

DON DUBE

HAROLD VANDERMOLEN

ABDUL SHEIKH

IRVINE GEIGER

PAUL LAIN

ALEX KLEIN

PETER BARBADORO

CHUCK MOULTON

HARRY BARRETT

NRC STAFF PRESENT: (cont.)
RAY GALLUCCI
SUNIL WEERAKKODY
MARK SALLY

ALSO PRESENT:
FRED MOGOLESKO
ALAN COX
BRYAN FORD
BRIAN SULLIVAN
STEVE BETHAY
KEVIN BRONSON
RAY PACE
FRANZ ULM
JIM RILEY

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

8:30 a.m.

CHAIRMAN SHACK: The meeting will now come to order. This is the first day of the 545th meeting of the Advisory Committee on Reactor Safeguards. During today's meeting the Committee will consider the following. Final review of the License Renewal Application for the Pilgrim Nuclear Power Station, revisions to Standard Review Plan Sections 19.0, Probabilistic Risk Assessment and Severe Accident Evaluation for new reactors and 19.2, Review of Risk Information used to support permanent plant-specific changes to the licensing basis general guidance.

Proposed recommendations for resolving generic safety issue 156.6.1, pipe break effects on systems and components inside containment, status of NRR activities in the fire protection area and preparation of ACRS reports. This meeting is being conducted in accordance with the provisions of the Federal Advisory Committee Act. Mr. Sam Duraiswamy is the designated Federal Official for the initial portion of the meeting.

We have received no written comments nor request for time to make oral statements from members of the public regarding today's sessions. A transcript of portions of the meeting is being kept and it is requested the speakers use one of the microphones, identify themselves and speak with sufficient clarity and volume so that they can be readily heard. I will now begin with some items of current interest.

A sad note, Commissioner Edward McGaffigan, the longest serving member of the NRC died on September 2nd, 2007. Commissioner McGaffigan was an extremely dedicated public servant. I understand that he was at a Commission meeting even last week. And that's, you know, extraordinary dedication. I had the privilege of hosting him on a visit at Argonne National Laboratory and the quickness of his mind and the breadth of his interest are truly astounding to me and he will be sorely missed.

On a pleasanter note, we have a new member of the ACRS who is joining us for the first time today, John Stetkar. And he'll be providing us with expertise in PRA and a broad breadth of experience and knowledge in actual working with operating plants. And so we think he's going to be a very helpful addition to the ACRS and we'd like to welcome him aboard. We have some new ACRS staff people. Mr. Girija Shukla joined the ACRS staff as a senior program manager on August 6^{th}, 2007. Mr. Shukla joined the NRC in 2000 and held a number of positions of increasing responsibility in NRR including technical assistance of the Director Division of Policy and Rulemaking. Prior to joining the NRC, Mr. Shukla had over 22 years of nuclear industry experience with a nuclear steam supply system vendor, an architect engineering company and several nuclear utility companies. Mr. Shukla received a Bachelor's Degree in Mechanical Engineering from the Institute of Technology, Banaras Hindu University, India and completed graduate level studies in nuclear engineering from the State University of New York, Buffalo, New York. Welcome aboard.

MR. SHUKLA: Thank you.

(Applause)

CHAIRMAN SHACK: Ms. Yoira Diz-Sanabria joined the ACNW ANM staff as a program manager on August 6^{th}, 2007. Ms. Diz-Sanabria joined the NRC in 2001 as a nuclear safety intern in NRR. She held a number of progressively more responsible positions including project manager. Ms. Diz-Sanabria received a Bachelors Degree in chemical engineering from the University of Puerto Rico and is currently pursuing a masters degree in chemical engineering from Johns

Hopkins University. Welcome aboard.

(Applause)

CHAIRMAN SHACK: Just a note of information for the members, the interview of a candidate scheduled during lunch time today has been postponed to October. So you're free to go your ways at lunch time today. On another note, this is Dr. Graham Wallis' last meeting as a member of the ACRS. Dr. Wallis has brought an immense amount of expertise to the committee in thermal hydraulics. He's given new meaning to the word "questioning attitude". We'll not likely see his equivalent as a linguist as an ACS chairman and member in my lifetime and he not only brought his own perspectives, but he's enlightened us many times on you know, the views of our work and the Commission's work in the eyes of Dartmouth sophomores, precocious and perspicacity is just too profound to believe and his Shakespearean colleagues who also had their own perspectives on the NRC and its work. And so we're going to miss Graham both for his technical qualities and his personal qualities and there was no one to remember more to join for dinner at the Pines than Graham.

MEMBER ARMIJO: Here, here.

CHAIRMAN SHACK: With that, it's time to

move on to our first topic of the day which is the final review of the license renewal application for the Pilgrim Nuclear Power Station and Otto will lad us through that.

MEMBER MAYNARD: Thank you, Mr. Chairman.

MR. BROWN: Hang on.

(Off the record comments.)

MEMBER MAYNARD: Thank you, Mr. Chairman. And as you can tell, we've had some people join us via telephone through the regional office and I think we have some members of the public, the press and also from the State of Massachusetts that's on the telecon.

Our subcommittee met to review the Pilgrim application April 4th and we had a good discussion on that. This is for the final review by the ACRS. There was a couple things that I want to make sure that we cover today. We have two hours for the staff and for the licensee presentations here. We want to make sure that we do cover the groundwater intrusion into the torus and it's something we identified last time to discuss with the full committee, also the fluence, the RAMA code and the benchmarking, make sure that we have a good discussion on that today.

Another thing that we really didn't discuss much last time but on the cumulative usage factor, I want to make sure we have a good understanding of what the final resolution is relative to that. Anything else is fair game.

Also those won't be the only three topics or questions that you'll get so before we start with the licensee, I'll turn it over to --

MS. LUND: Thank you. Hi, my name is Louise Lund and I'm the Branch Chief for License Renewal Branch A and I want to thank Dr. Shack for his kind words about Commissioner McGavigan. We share your sentiment and he will be missed very much. This morning we're going to continue with our Pilgrim License Renewal presentation. Today we have with us Perry Buckberg who is the Project Manager and we also have Glen Meyer, who is the Team Leader for the Inspection Team. We also have Dr. Jim Davis, who is also the Audit Team Leader and besides myself, Dr. Kuo is here, the Division Director for License Renewal.

And as Dr. Maynard was mentioning, we still -- we had two open items when we saw you last for the subcommittee meeting and those two items that we're going to be discussing are about the groundwater and also the fluence issue as well and we are currently preparing a supplement to address the metal fatigue issue which is the other issue that you mentioned.

So without further ado, I will turn it over to Steve Bethay from the Applicant.

MR. BRONSON: Thank you very much, Louise. Good morning. I'm Kevin Bronson. I'm the Site Vice President for the station. Thank you to the committee for giving us the opportunity to meet with you today. We're happy to be here as we near the end of the license renewal process for Pilgrim Station. The interaction between the entity team and the NRC staff has been very professional and productive throughout the process. We appreciate the diligence and the technical competence of the NRC staff as they validated that Pilgrim Station has met the requirements of the license renewal process.

Our organization is fully prepared to implement all the commitments that have come out of the license renewal process and those commitments have been placed in our commitment tracking system and have clear ownership established. I'd like to introduce the team now. On my right is Steve Bethay. Steve is our Director of Nuclear Safety Assurance. On Steve's right is Brian Sullivan. He's our Director of Engineering. On Brian's right is Bryan Ford. He's our Fleet Licensing Manager. On Bryan's right is Alan

Cox. Alan is the Fleet Licensing Manager for license renewal. On Alan's right is Fred Mogolesko. Fred is the Pilgrim Station Senior Project Manager for license renewal.

We also have a host of others here for support, including John McCann, our Director of Licensing for the Fleet. And with that, I'd like to turn it over to Steve for the presentation.

MR. BETHAY: Okay, good morning and thank you for having us this morning. If you can go to the next slide, please. The quick agenda that I'll cover today is similar to what many of you heard at the subcommittee meeting for those items that we dwelt on back in April, I'll go through quickly, pending whatever additional discussion you gentlemen would like to have. We'll talk about the description of the plant, a brief summary of our licensing history and highlights, talk about our project.

I'll mention the draft open items or the draft SER open items that came up and then our resolution of those. On the cumulative fatigue usage factor, I did not include any slides on that issue in here but I am prepared to discuss it so I propose just remind me if we don't do it in the middle, at the very end, I can certainly discuss the resolution of that item.

Now, company description, we are located in Massachusetts, right on the shores of beautiful Cape Cod Bay about 40 miles south of Boston, 1600 wooded acres on the south shore. We are a BWR-3 with a Mark 1 containment, General Electric design. Bechtel was our architect/engineer. We're currently licensed at 2028 megawatts thermal and we produce about 690 megawatts electric. We are an open cycle condenser cooling, once through system back to Cape Cod Bay. We're owned and operated by Entergy Corporation of New Orleans, Louisiana and we currently have a staff of around 650 employees including our security force which is an in-house security force.

Our current plant status, back in the spring, actually just as we went to the subcommittee meeting, entered our refueling outage number 16. We completed that in early May. They're currently operating at 100 percent steady state power. All of our NRC performance indicators are green and all inspection findings are green and we're in column 1 of the regulatory oversight process. Our next refueling outage is currently scheduled for April/May 2009 time frame.

Just quickly to update you and refresh

your memory on the licensing history and highlights of the station, we did obtain a full power license in September of 1972, a commercial operation in December of that year. The plant was owned and operated by the Boston Edison Company up until July of 1999 at which time Entergy bought the Pilgrim Station in the first commercial sale, open market sale of a nuclear plant.

We're proud of the successful transition that occurred on July 13th of 1999. Entergy has been the owner and operator of Pilgrim since that time. In 2003 we did the small feedwater flow uncertainty. Power uprate we refer to as Appendix K power uprate. We submitted our license renewal application in January of last year in anticipation of the current operating license expiration date of June 8th, 2012.

I'm not going to read these slides to you. I'll let you skim those but I just want to use next couple of slides as a reminder that you know, we've been preparing the plant for continued operation almost since it started up. You know, over the years we've made a number of modifications to improve the containment structure. We've replaced IGSCC susceptible piping. Pilgrim was one of the first plants in the mid to late '80s to really embark on a safety enhancement program. We were one of the first plants to do the items listed such as a Director station blackout diesel generator. We continued those efforts into the '90s. We were an early plant to introduce hydrogen water chemistry. We did the ECCS suction strainer replacement in the mid-'90s and noteworthy in this past spring we implemented noble metal chemical addition for IGSCC mitigation this spring.

It's noteworthy also that our spent fuel pool capacity is adequate through the current operating license period. But we will have to go to a dry cask storage-type facility if the license is renewed for an additional 20 years. We've started that project through our capital funding authorization process and we'll start engineering work on a dry cask storage facility next year.

Our license renewal project --

MEMBER MAYNARD: When do you run out of capacity in your spent fuel?

MR. BETHAY: We will have full core off-load through the current operating license and then after that for refueling outage in 2013, we would have to have them.

Our license renewal application was prepared by a multi-disciplined Entergy team, both what we call corporate, most of them are actually based out of Arkansas, that have done the Entergy license renewal applications for the fleet, heavy involvement from the site in that as well. We did extensive training to the engineering, licensing and QA staffs very early in this process so that we had full buy-in from all parties involved and a full understanding of the license renewal process and rules and regulations that go with it.

Noteworthy, the Pilgrim and our companion plant, Vermont Yankee were the first applications submitted following the issuance of Rev 1 of the Standard Review Plan and the GALL. So we believe that we have fully incorporated all of the aspects of Rev 1 of those documents. We did incorporate lessons learned from other applications. I'll just go ahead and note that one of the issues that we went back and addressed, I know you're familiar with the scoping issues that had come up in the Vermont Yankee application, when that issue was identified at VY, we went back and reviewed our application very carefully and we're confident we didn't have the same issues that our brothers at Vermont encountered.

We did early on in the process, very early in the process, found some instances where our scoping boundaries needed some adjustment or revision. Those were addressed very early in the process and I'm quite confident that the implementation issues that VY saw are not applicable to Pilgrim and we would continue to factor in those lessons learned as they're identified at one of our plants or any other plant.

Our application did undergo a peer review by 10 utilities. We received a couple of hundred comments from the peer review before we submitted the application. All of those comments were addressed. Our application went through a very rigorous in-house review from our on-site safety review committee, our off-site safety review committee, our quality assurance department, as well as the discipline technical reviews within the engineering organization.

MEMBER APOSTOLAKIS: What is your core damage frequency now?

MR. BETHAY: The exact number, Fred?

MR. MOGOLESKO: Approximately 10^{-6} if you include seismicity.

MEMBER APOSTOLAKIS: Yeah, everything, the total. The total is 10^{-6}?

MR. MOGOLESKO: Approximately.

MEMBER APOSTOLAKIS: Including earthquakes and fires?

MR. MOGOLESKO: The fire is not necessarily subsumed into that number because we didn't do a PRA model. We used the five methodology which is --

MEMBER APOSTOLAKIS: Extreme.

MR. MOGOLESKO: Yeah, but we've enhanced the model that you, yourself, participated in multiple years ago with refinements through the 2003 years, are being reported in Appendix E.

MR. FORD: Yeah, we updated it around 2003.

VICE CHAIR BONACA: So is it Level 1?

MEMBER APOSTOLAKIS: CDF, yeah, but you have LERF customers.

MR. MOGOLESKO: Yes, sir.

MEMBER APOSTOLAKIS: Now, that's kind of low, isn't it, John, 10^{-6}?

VICE CHAIR BONACA: But only internal events, no, for --

MEMBER STETKAR: It's on the low end.

MEMBER APOSTOLAKIS: Yeah, it's on the low end.

MEMBER STETKAR: For that generation of boilers, but it depends on what they have in the plant.

MEMBER APOSTOLAKIS: Right, and how they did it.

MEMBER STETKAR: Do you shutdown also?

MR. MOGOLESKO: Yes, we do have a shutdown.

MEMBER STETKAR: You do?

MR. MOGOLESKO: Yes. I mean, the final CDF that I didn't mention, these are reflection of enhancements that went in under our safety enhancement program under Bob Denero's five initiatives in the late '80s and subsequent enhancements that we've made from the IP and the IPEEE.

VICE CHAIR BONACA: What is included in this for the number. What's included? Is it a Level 1 PRA? Does it include shutdown, you said.

MR. MOGOLESKO: No, it doesn't include the shutdown but we have done a shutdown PRA.

VICE CHAIR BONACA: Okay, but, you know, you talk about different pieces and then you're giving us a number and I'm trying to understand really what is included in the scope.

MEMBER APOSTOLAKIS: What is the number for the shutdown PRA? That's another question that's relevant.

VICE CHAIR BONACA: I'd like to know

what's inside the 10^{-6}.

MEMBER APOSTOLAKIS: I guess 10^{-6} is at power, that's my guess.

MEMBER STETKAR: It's probably at power mostly internal events in terms of reasonably quantitative.

MEMBER APOSTOLAKIS: He said it includes seismic and a bounding analysis for fire. So it's really everything.

MR. FORD: No, the number he gave out did not include a fire PRA.

MEMBER APOSTOLAKIS: Well, that has been screened out.

MR. FORD: Well, we did the five methodologies, so there's not -- in the number he gave there's not a fire PRA.

MEMBER APOSTOLAKIS: No, but if you screen it out, the number is there, right?

VICE CHAIR BONACA: Is it included, for example, internal flooding, high wind and tornadoes?

MR. MOGOLESKO: Yes, sir.

VICE CHAIR BONACA: So you have some external events.

MR. MOGOLESKO: Yes.

VICE CHAIR BONACA: And some --

MR. MOGOLESKO: Flooding, precipitation, probable maximum.

VICE CHAIR BONACA: So it's -- okay.

MEMBER STETKAR: External events?

MR. MOGOLESKO: Yes.

MEMBER STETKAR: Hurricanes?

MR. MOGOLESKO: Yes, the greatest majority of those screened out. The screening criteria was $1E^{-6}$, the site flooding, the PMP.

MEMBER STETKAR: $1E^{-6}$ is a difficult screening criteria and if your total is $1E^{-6}$.

MEMBER MAYNARD: Steve, you might want to go ahead and move forward.

MR. BETHAY: Okay, thank you. The license renewal project to get back on track with this, the commitments in our process have been refined as needed over the process and our interactions with the staff. A number of the commitments have been refined to address various issues. We've captured all of those in our commitment tracking process and all of those commitment -- the implementation of those not only are monitored through our commitment process, but we have a senior management process where actually weekly we review the status of all NRC commitments, so they'll remain in the forefront as we go through these.

We've got 14 programs that will be in place without significant enhancement, 16 programs that require some degree of revision and enhancement and 10 new programs that will be implemented as part of the license renewal. And with that I'd like to go to the open items which I think is the meat of what I understand you wanted to talk about.

In the draft SER there were four open items, one dealing with the security diesel generator, fire barrier penetration seals, containment and service inspection and that includes the water on the torus room floor that we'll talk about and reactor vessel fluence. The final SER came out in late June with all of those open issues resolved.

The first two are fairly simple and straightforward. The first one had to do with the scope of whether or not the security diesel components were within the scope of license renewal. That was referred to the region as a confirmatory item. Additional work was performed by the region and we understand that that was resolved satisfactorily.

On the fire barrier penetration seals, we had an unfortunate wording in our application which implied that we had inaccessible fire barrier seals that would be obviously, very difficult to inspect.

The correct wording should have been we don't have any inaccessible fire barrier seals and all fire barrier seals are within the scope of the program.

With that I'll move to --

MEMBER POWERS: How many fire barriers or penetration seals do you actually have to inspect?

MR. BETHAY: The absolute number?

MEMBER POWERS: Yes.

MR. BYRD: Can somebody help me with that? I don't know the total off the top of my head. Can we look that up and get that to you at a break? I don't know the total right off the top of my head.

MR. FORD: It's several hundred but I don't remember the number.

MR. COX: This is Alan Cox. We have other sites where the number is around 1400.

MEMBER POWERS: 1400 is the number that's often encountered.

MR. BETHAY: Sorry, I didn't have that one on the top of my head.

MEMBER POWERS: I'll hold that against you.

(Laughter)

MR. BETHAY: Thank you.

MEMBER POWERS: It's a number I keep on

the top of my head, having no hair up there.

(Laughter)

MR. BETHAY: The containment inspection in-service program was the open item that we'll spend the most time on here. The open item was characterized as the potential for corrosion of the inaccessible areas of the steel containment shell, base mat and sand pocket region, basically stemming from the issues at Oyster Creek. We had -- this is basically a review of the same thing. I'm not going to go into nearly the detail that we did at the subcommittee meeting, so if I'm doing too much, too little, please move me along.

Our drywell shell condition and monitoring, we have a defense in-depth design that minimizes the potential for undetected water intrusion into the gap between the containment liner and the concrete. We have a number of diverse methods of preventing water as well as the identification of any water that could get into the air gap. Historically, we've had no refueling bellows leakage and we've had no water intrusion into the air gap. The UT measurements and inspections over the years have shown no drywell shell degradation and we have committee to perform confirmatory inspections in the future to verify that that's still the case.

If you'd look at the next slide, you can see it, I just want to point out the difference in monitoring capability that we have. The top left portion where you see the number 1 indicates a three-inch line that comes off of the bellows assembly that's intended to detect any gross leakage from the refueling cavity into the liner area. That flow switch has a set point of six gallons per minute. It does alarm in the control room. That's intended to detect gross leakage that may come from a refueling bellow's failure.

We also have noted by number 2 on the top right of the screen four drains that come off of the refueling cavity bellows area that attach to three quarter inch tell-tale drains that empty out visibly on the 74 foot of our reactor building. Those tell-tale drains are surveilled routinely by operators. Any leakage would also be detected through those and be visible literally on the floor or flowing into a floor drain on the 74-foot elevation. Should those fail or be overcome, down at the bottom you'll see number 3 on the left-hand side of the screen. You can see that we have an above sand pocket drain. That taps into the area of the drywell shell just above the sand pocket region and drains out into a catch container, a bucket, down in the torus room where any leakage that may have passed the first two detection systems would be collected there and those buckets are also looked at to be sure that they remain dry and any leakage would be investigated.

Beyond that, Item Number 4 is a two-inch sand cushion drain. There are four of those around the periphery of the containment structure. They would also drain water from the sand pocket region. Our inspections over the years have shown those buckets to remain dry. There's no indication of water having leaked down in that area. About 19 -- in the late '80s boroscopic inspection ports were drilled into those lines so that we could inspect the lines to make sure that they were clear. They were verified to be unobstructed. We also took that opportunity to do a limited visual inspection of the drywell liner in those four locations, also verified to be in good shape.

Now, from this point, I can go through each of those in detail or not.

MEMBER MAYNARD: I just have a couple of quick questions.

MR. BETHAY: Yes, sir.

MEMBER MAYNARD: Item 4, the number 4 there, does that provide you any indication? It would be a path for it to drain off but do you have any way to tell if any got to there?

MR. BETHAY: Just visually. You can actually see it. If you go to -- the small area where the red line indicates coming down, that's a very tight space but you can actually stand in there and the green line that indicates a below sand pocket drain is right over your head. So if there are any leakage, it would be evident either obviously, dripping or in the collection containers below.

MEMBER MAYNARD: And Item 1, the flow switch, is that the one that was found inoperable and you made commitments to --

MR. BETHAY: It's been fixed, yes, sir. That's the one, yes, sir.

MEMBER WALLIS: Could you remind us about what's in the air gap between the steel and the concrete? Is there -- is there some material in there or not?

MR. BETHAY: There were foam structures placed in between the concrete and the steel during construction that were -- as the concrete was placed coming up the sides, those large blankets I'll call it, of foam material were removed. There were foreign material barriers put in rings of a foam material at various elevations as the containment was built. It's unclear that all of those were removed during original construction so we believe that in the upper cylindrical portion of the drywell, there likely is a ring of foam call it.

MEMBER WALLIS: The concern would be if water are leaked into there but didn't make it down --

MR. BETHAY: Right.

MEMBER WALLIS: -- but then acted to corrode the shell.

MR. BETHAY: Right, we recognize that potential and we do have the ultrasonic inspection program that surveils that location in a six-foot vertical strip.

MEMBER WALLIS: Did you measure the humidity in the gap or anything like that?

MR. BETHAY: No, sir, but we do UT's to verify the condition of the shell at that location were we suspect there's a -- there was a foreign material barrier that was probably left in place. So a question to the committee, do you want me to go through these next four slides in detail or move along?

MEMBER MAYNARD: I think we can move along. We've covered these in detail in the subcommittee.

MR. BETHAY: Okay, very good. In that case, let's get to Slide 20. To our past inspections, as I mentioned, we have done UT's in the past. We did 12 locations at the nine-foot two elevations, which is the floor elevation inside the drywell. We also chipped out the concrete a depth of an inch in four locations so an inch into the sand pocket region, we did confirmatory ultrasonic exams there and as I mentioned, the locations in the upper elevation where we believe the backing ring or FME barrier is probably still there.

We also -- and all of those results were acceptable. We verified that the upper sand cushion drains were unobstructed and dry and throughout all of our inspections we've seen no indication of corrosion or degradation of the steel liner.

MEMBER POWERS: Can I just ask a question about wording?

MR. BETHAY: I'm sorry?

MEMBER POWERS: Ask a question about wording.

MR. BETHAY: Yes, sir.

MEMBER POWERS: You said the results were acceptable and yet your slide says, "All inspections identified no corrosion".

MR. BETHAY: We've seen no evidence of degradation.

MEMBER POWERS: Steel has no corrosion.

MR. BETHAY: We've seen no indication of corrosion based on the UT results.

MEMBER WALLIS: It looked shiny?

MEMBER POWERS: That would be remarkable.

MEMBER WALLIS: It would be remarkable.

MR. BETHAY: You can't see it so, from the UT results we've seen no indication.

MEMBER WALLIS: From the UT results, it's not from the visual.

MR. BETHAY: That's right, these are all UT results.

MR. SULLIVAN: And the UT results all show nominal wall thickness or greater?

MEMBER POWERS: Thank you.

MR. BETHAY: In the future, moving on to Slide 21, Ed, we have committed as part of the license renewal process that we would re-perform the 12 locations at just above the sand pocket region inside the containment, once prior to the period of extended operation and then once within the first 10 years. Also, we've committed to remove the grout at four locations, once before the extended operation and once within the first 10 years and will continue to do the upper elevations as part of our IWE code compliance program.

MEMBER POWERS: Why just above the sand pocket?

MR. BETHAY: I'm sorry, sir?

MR. PLUMMER: Why did you select just above the sand pocket?

MR. BETHAY: That's the most likely place where it would be wet and stay wet for a period of time based on the mid-'80s issues that stem from Oyster Creek and their findings of moisture traps, so to speak, in the sand pocket region and that's why those areas were selected.

MR. FORD: We have a steel plate right at the top of the sand cushion and so this would be seeing whether or not there was corrosion for water building up on top of the steel plate.

MR. BETHAY: So I'm very confident that our containment is in good condition today and we've got a program to verify that in the future. Moving onto Slide 22, which I think is the meat of what you gentlemen want to discuss today is the issue of water on the torus floor. If you'll flip to Slide 23, as you'll recall from our ACRS subcommittee presentation, we've had an issue with water puddling on the floor of the torus room over the years. This is not a new phenomenon. The water has been on the floor for a number of years. We discussed that at length at the subcommittee meeting. We do have some additional information. We have fulfilled the commitments that we made at that time. And I just want to take a little step back and refresh your memory of what we're talking about.

Slide 23 is a plan view of the torus and the torus compartment. The torus is divided into bays, 16 bays that are the segments of the torus what are welded together. You can see on here the column lines are noted one through 16, as you move around the torus. The dotted lines that you see represent the construction joints of the base mat and the concrete pedestal. That's important later in our discussion. The areas of historical wetness are Bay 10 which is top dead center on your picture and Bay 6 which is hard right on the picture.

We occasionally, you know, see water in other areas. Normally, that's due to condensation.

I was down in the torus room about two weeks ago. It was very hot, humid day. The torus, obviously, is full of cold water and the condensation was significant. There was a good bit of condensation on the sallow torus. So we see condensation in the summertime. What I want to focus on today is the sources of water that are not condensation, that typically show up in the wintertime more easily visible. So Slide 24.

Bay 8 is a bay that's typically dry. These pictures were taken back in February when the humidity was fairly low. So the condensation contributor is small in this case. So Bay 8, typically dry. I'll point out in the middle of the screen there, you can see two of the torus tie-down bolts. Those are the rock bolt anchors that we discussed back in April. And you can see the support structure.

Just for a perspective here, the reactor pedestal is to the left in this picture and the building wall is to the right in this picture, so we're sort of looking under the torus back towards the reactor pedestal and that also will become important in a minute. Slide 10 or the next slide shows Bay 10. This is one of the bays that is typically wet and is actually the one that's, you know, almost always wet when there's no condensation. You can see the rust as indicated on some of the base plates of the anchor bolts. Just as a reminder, the yellow tinted area on the right picture was an effort to try to determine whether or not we had water coming up around the anchor bolts and trying to determine if that was the source of the water on the floor. That tinting structure has been removed. It's not there any more and I can explain some of the results of our inspections and why that was the case.

MEMBER MAYNARD: That was put there to keep the water out.

MR. BETHAY: Yes, sir, the theory at the time, which we'll talk a little more about, is now a suspect theory, was that groundwater was seeping up around the grout of the anchor bolts and seeping out onto the floor. We built this containment structure, this is just a little dam with a tent over it. We dried it out very good. The water reappeared. So the hypothesis was, the water is coming up around the bolts and as we talked before, we -- you know, we know that the water vapor under the plant is degraded and the groundwater coming in and I'll get back to that point in just a second.

Slide 26, the aspects that we've evaluated of the water on the floor was obviously, what's the source of the water, where's it coming from, the integrity of the anchor bolts in the steel structures, is there any adverse effect due to this water. The structural adequacy of the reactor building given that obviously there's a seepage path for water to come in. And then inspection and monitoring of the water, the concrete and the torus hold-down bolts.

We also had an independent assessment performed by Dr. Franz Ulm, who is with us today from MIT to you know, help us with whether our theory has made any sense in a true engineering sense. So Franz is here to help with questions as necessary. Slide 27, we had determined conclusively that the source of the water is groundwater seepage under hydraulic pressure. The groundwater table or groundwater table around the plant is fairly high from the nominal water table to the bottom of the base mat is 21, 22, 23 feet. So it's under a pretty heavy static head.

We believe that the path is through the vertical joints and zones most likely weakened by the actual construction process and the setting of the concrete. We believe that to be a normal occurrence and we can go back and look at some of these construction joints and how this can be. The low seepage rate is counteracted by evaporation. It's not a quantity that has to be pumped out or vacuumed up. It's kind of an equilibrium condition. What comes in evaporates and then a little more seeps in.

It is a non-aggressive benign water chemistry. The integrity of the anchor bolts, as you'll recall back in April, we committed to you that we would make every effort to inspect the bolts and the interface between the bolts and the concrete and the grout and that we would inspect the condition of the grout surrounding those bolts. We did that. We removed one bolt in Bay 8, which as I showed you, is a dry bay. We removed the nut and the jacking plate, if you recall we had a long discussion about that.

Removed the nut, lifted the jacking plate and found that the interface of the concrete, the grout and the bolt was almost pristine, no indication of any degradation whatsoever at the interface between the bolt and the grout. The grout was sound, intact and really in very good condition at that point.

MEMBER ARMIJO: How much degradation would cause you any problem, assuming if you had any damage to the bolts, you know, how serious would that be?

MR. BETHAY: Ray, can you -- where is Ray

Pace, our Design -- Civil Design Manager?

MR. PACE: Ray Pace, Pilgrim Station. There's a design factor of safety of 2 on the anchor bolts, so there is sufficient margin there for any kind of minor degradation that one might incur due to corrosion.

MR. BETHAY: We also inspected four bolts in Bay 10 because they had obviously been wet. Those were a little tougher to get off. We were able to remove the nuts and plates in four locations that were typically wet. That included removal of the jacking plate or the base plate that was down there. And we also found the same results, we found the grout in very good condition. We didn't see any evidence of a clear water flow path. It did appear solid and structurally sound. We saw no degradation or significant rusting of the bolts or the interface where it had been in the water.

So we dried that out as best as possible without, you know, getting it squeaky dry, but we didn't see that as a clear source of water either. We didn't see that as the flow path that we had suspected.

MEMBER MAYNARD: Just briefly go back over the purpose of these bolts again.

MR. BETHAY: Yes, sir, the bolts, they're three foot long Williams rock bolts that are intended to hold the torus down from chugging and uplifting loads in a blow-down event.

MEMBER CORRADINI: And so they're into the concrete.

MR. BETHAY: That's correct.

MEMBER CORRADINI: Okay, and so the wall I see them on which is the bracket, that wall then is attached to the torus higher up. Is that correct?

MR. BETHAY: That's correct. That wall is actually a beam. It's a support beam that is welded to the torus and it's bolted to the floor. There are eight bolts on -- eight bolts on each side and if you go back to the plan view which was --

MEMBER CORRADINI: So when I see a wall, that's just really an extension of the torus down to the floor.

MR. BETHAY: That's correct.

MEMBER CORRADINI: Okay, thank you.

MR. BETHAY: That's correct.

MEMBER ARMIJO: Those bolts are really studs.

MR. BETHAY: They're rock bolts, yeah. They have a wedge on the bottom. You drill a three-inch hole, drop the bolt in. It's jacked up to expand the wedge at the bottom and then a nut on the top, too, to post-tension.

Our inspection showed that the bolts are in good shape. The concrete and the grout are in good shape and that path was not the clear path. I can't say that it's definitely not a leakage path but I also can't say that it definitively is the leakage path. Past sampling, I'm on page 29, Ed, past sampling of the water is demonstrated it's non-aggressive chemistry. We've seen no structural distress. You walk around the walls, you don't see spalling or big cracks in the wall. There are normal hairline cracks that you see in any concrete structure but nothing that would indicate that the whole structure is in any structural distress.

We determined that the groundwater is not aggressive to the concrete or to the base mat. You can see the results of the chemistry that we've -- water chemistry analysis that we've performed were well within the bounds of what one might consider to be an aggressive environment for the concrete and the anchor bolts. We've re-analyzed it and again, determined this water to be groundwater. We know it's not any process water in the plant. We know it's not sea water coming in.

We believe that it's groundwater coming into the plant because the waterproof membrane underneath the base mat is deteriorated and through the normal fissures and construction joints and seepage paths through such a large concrete structure it finds a way onto the floor.

MEMBER MAYNARD: The criterion you used to say it's non-aggressive is that based on the GALL definition?

MR. BETHAY: Yes, sir, that's based on the GALL definition. So future commitments on page 30, obviously, we need to determine what additional actions based on inspection of the bolts and the water analysis and I'll talk to that a little more in just a second, will continue to do that until we definitively find and come up with a repair plan for the source of the groundwater. We'll continue --

CHAIRMAN SHACK: Just hold on. Did you actually measure the pH of that seepage water?

MR. BETHAY: Yes, sir.

CHAIRMAN SHACK: What is it?

MR. BETHAY: Do you remember the number, Fred? You have that number.

MR. MOGOLESKO: The pH of the seepage

water has ranged and a function of time between 8.7 and 9.5.

MEMBER ARMIJO: You just collected a sample from the floor?

MR. BETHAY: Yeah, we just scoop up a little bit.

MEMBER CORRADINI: Since we're on this, so did you do any monitoring of what you would get from groundwater outside the plant to show that it's similar?

MR. BETHAY: That comparison was done.

MR. MOGOLESKO: It is calibrated with the concrete so --

MEMBER POWERS: So it would be different.

MEMBER CORRADINI: It would be different after it's aged through the concrete.

MEMBER POWERS: It's much higher pH than the groundwater.

MR. MOGOLESKO: We do do the external groundwater measurements three or four times since the license renewal project began.

MEMBER CORRADINI: You'd think the pH would be different, but do you think all the other residual chemicals would be different, too, from them?

MEMBER MAYNARD: You would pick up some.

MEMBER POWERS: You would pick up some from these but I mean, anything that's in concrete won't be there.

CHAIRMAN SHACK: But the mild alkalinity is good for the steel.

MEMBER MAYNARD: What you're saying is what you found is consistent with groundwater that had seeped through a concrete structure.

MR. BETHAY: That's correct. That's correct.

So we'll continue to monitor that water. Before we move onto the assessment because I think what Dr. Ulm's assessment showed is consistent with what we found, we did -- after we looked under the bolts, and I don't have any additional pictures of this, but I wanted to share with you our inspection results. After we lifted the bolts and removed the jacking plates and we found that that path was not clearly the source of the water, we continued to look and actually I and Gary Dyckman, who is with us today, went back into the hidden recesses and nooks and crannies of the foundation pedestal and we actually found in the area, if you can flip back to page 23 in your book, in the area of column line 11, where you see the red dots at the 11:00 o'clock view, you see the little red dots. We found on the reactor pedestal about two feet up, evidence of tiny pits, tiny cracks, that clearly had water seeping out and you could actually see the water seeping, a very slow, very small rate, but you could see the water seeping out, running down the column line and onto the floor by where Bay 10 shows to be wet. So with that in mind, if you'll flip to page 25 --

MEMBER WALLIS: Could you reassure us why you know that that water did not come from the reactor?

MR. BETHAY: Well, we've done the radiological analysis.

MEMBER WALLIS: Radiological analysis.

MR. BETHAY: We know it's not reactor water. And if you look at page 25, the right-hand picture, the area that I just described is, if you'll follow from the tent back to the left, up under the torus, there's a buttress where that beam ties back into the pedestal and I'm going to confuse you a little bit but if you'll indulge me and flip between page 15 and page 20 or the page 23 and page 15, the elevation view of the containment and the plan view.

MEMBER ARMIJO: How do you get into the space between the torus and the pedestal?

MR. BETHAY: You lie on your stomach and you slide under like this. It's a very, very tight fit.

MEMBER WALLIS: How young do you have to be to do that?

MR. BETHAY: 50, you can do it at 50. It's a very tight fit and I think that's been part of the difficulty in determining this path. You know, the early belief was the water was coming around the bolts. The bolts were a hole that was drilled into the concrete. The water seems to be around the bolts so that was the hypothesis. When you lie on your stomach and shimmy back into these very tight spaces, you can find physical evidence that -- and you can see water seeping out -- seeping is the right word, I think. It's a very -- weeping. It's a very small amount. It's steady but it's a very small amount of water.

MEMBER CORRADINI: Is that the same way you get in to see the red and the green line?

MR. BETHAY: Yeah, it's the same.

MEMBER CORRADINI: So it's the same operating procedure.

MR. BETHAY: It's the same procedure. Same way you get there.

MEMBER CORRADINI: And so what elevation are you seeing this weeping?

MR. BETHAY: If you'll -- at the bottom of this picture, you'll see the words that say "four-inch upper sand drain", if you'll follow that arrow to where it points to the red line, among the elevation view. And this was not intentional but where the right-hand tip of that arrow that's pointing to the red line, is where we see the seepage.

MEMBER CORRADINI: So you're about 15 feet below the water level.

MR. BETHAY: That's correct, 15 to 20 feet below water. It's under fairly steady hydraulic head.

MEMBER CORRADINI: But it's coming through cracks up to that point and weeping out into the space.

MR. BETHAY: Right and consistent with Mr. Ulm's analysis, just below that you can see the vertical construction joint and you can see that the pedestal actually overlaps that a little bit. So this is quite consistent with Dr. Ulm's hypothesis that water is seeping under hydraulic pressure along construction joints that would be expected, up and then through minor, minor cracks and small imperfections and concrete, the path of least resistence --

MEMBER WALLIS: That's also about where you might expect the weight of all the reactor and all that stuff up there to come down on the base mat, isn't it?

MR. BETHAY: I think that would be true. I think that the location of the construction joints is probably a greater contributor to this. So I'm quite encouraged, actually, that the hypothesis that we gave you guys back in April that you know, the base mat barrier is degraded and we're seeing seepage underground water hydraulic pressure through construction joints and minor to be expected discontinuities in the concrete just from the normal construction. Where we actually see the water is consistent with that.

MEMBER WALLIS: It has to seep a long way.

MR. BETHAY: It's actually not that far. It's -- from the centerline of the torus back to that wall is probably 10 feet, 15 feet, and now if you look at the photographs again, on page 24 or 25, the floor is actually slightly concave if you look at the construction details. So it makes sense based on what we've observed now, that the water is coming from the pedestal under hydraulic pressure, very near a construction joint, running down this beam onto the floor over the bolts where it's slightly concave and that's consistent with the picture that you see.

MEMBER WALLIS: We're on that coming a long way. It has to go through it would be 12 feet of concrete to get there.

MR. BETHAY: Oh, yes, yes, and that's --

MEMBER WALLIS: So it's very unlikely that that hole is going to get any bigger.

MR. BETHAY: That's correct. That's correct. And again, the observation is that it's a very, very small amount of water coming in but it's steady. So over time, you end up with a puddle. So corrective actions for that is we --

MEMBER ARMIJO: What's very small?

MR. BARDIN: Very small amount?

MEMBER ARMIJO: Right.

MR. BETHAY: I couldn't -- I'm not even sure I could quantify it. The point source that I observed was maybe the size of the end of a pin.

MEMBER WALLIS: Dripping or dribbling down the wall?

MR. BETHAY: It's just dribbling down the wall, but it's a steady -- it's not like --

MEMBER WALLIS: Like what comes out of the tap on a maple tree, something like that.

MR. BETHAY: Not quite that fast. I didn't try to quantify it. I didn't try to quantify the flow rate but it's --

CHAIRMAN SHACK: But it's too fast to just sit there and evaporate and build up deposits.

MR. BETHAY: It's too fast to evaporate on the wall but it's too slow to attach a flow rate to it. You know, I liken it to my home. I have a crack in my basement wall and, you know, when it rains hard and the crack gets wet, and --

MEMBER WALLIS: So it's maybe a couple of gallons a day or something like that, is it?

MR. BETHAY: Yeah, probably something in that range. I mean, maybe Franz, do you have an opinion on that based on what you've seen?

DR. ULM: Franz Ulm. I asked to investigate this here. So the combined of the amount of water which can likely get into there is the amount of water that gets through a four meter cylinder in time. So that's -- if you take all the discontinuities, all the cracks together and put them together, that's about the amount of water which you get there. And that amounts to a few gallons per day and the full pressure, of course, in some it's a little bit less because the humidity is higher and you have the evaporation going on.

MR. BETHAY: So our challenge now is how do we fix this.

MEMBER WALLIS: Well, it would be interesting to see if it seals itself.

MEMBER MAYNARD: It hasn't done it in all of these years.

MR. BETHAY: It hasn't done it.

MEMBER MAYNARD: I think we need to move to what assurance do we have that his not causing any structural integrity damage?

MR. BETHAY: Okay, very good. So let's get back on track and we'll go to page 31 and this is actually our assurance that we're not causing any damage. We asked Dr. Ulm to help us with that evaluation. That assessment was that that groundwater migration is highly localized. It doesn't compromise the overall structural performance of the base mat or the reactor pedestal. There's no effect in the bulk integrity of the slab or the overall compressive and bending loads that we see in the foundation.

The non-aggressiveness of the water to the concrete has been verified and the local calcium leaching that we see doesn't effect the overall structural performance of the slab. Kind of the highlights of Dr. Ulm's assessment. And in the sake of time, I won't ask him to address that but move on unless there are other questions here.

VICE CHAIR BONACA: Well, on page 30, you have future commitments.

MR. BETHAY: Yeah, future commitments on page 30 that we will determine as I mentioned, what corrective actions need to be taken as a result of the findings that we've seen. We'll continue to monitor the groundwater. We'll continue to monitor the chemistry, prior to the period of extended operation and once every five years. Obviously, if we completely stop the seepage, then that commitment might be altered. And they will continue to inspect the structure in accordance with our structure's monitoring program every five years. So those are --

MEMBER WALLIS: Well, you've got a very low pressure driving this.

MR. BETHAY: Yes, sir, it's --

MEMBER WALLIS: You could almost seal it up from the inside.

MR. BETHAY: Well, we discussed a couple of repair options but we haven't decided which one would be the most effective. So that's still -- it's part of our corrective action program.

MEMBER POWERS: Is this a place to leak?

(All talking at one time.)

MEMBER MAYNARD: I think it's a noble effort to try and stop it. The main thing you need to do is to have a program in place to assure that it's not causing any structural damage.

MR. BETHAY: That's right and that's the structural monitoring program that we have in place to do that.

MEMBER MAYNARD: We need to be moving onto the next subject. I don't want to take all the staff's time.

MR. BETHAY: Okay, I'll go as quickly as possible. The next open item had to do with neutron fluence calculations. Our current PT curves are valid through 2011 refueling outage. We do have a commitment to submit calculations that are conformant or compliant to Reg Guide 1.190 by June 2010. We have evaluated all of our time limiting aging analysis that -- to determine the limiting fluence. We've determined based on that review that our limiting fluence values currently would not be exceeded after 54 effective full-power years but we don't have an analysis that's consistent with the reg guide methodology.

So we've accepted a license condition on page 34 that says on or before June 8th, that we will submit to the NRC correctly benchmarked neutron fluence calculations that are consistent with the reg guide and that will confirm that the neutron fluence for the shell wells, the inner surface, will not reach the limiting value by the end of the period of extended operation. So that's the license condition that we'll have to fully resolve this prior to 2012.

MEMBER MAYNARD: Do you have a plan on how you're going to do it?

MR. BETHAY: Yes, sir, and the plan right now is a parallel path. We'll be using benchmarking data from another BWR-3 that EPRI is doing to benchmark the code for a BWR-3. We're also in parallel pass we're preparing to precisely identify the location of the remaining capsule and our vessel and remove that capsule for its own dosimetry analysis in our next refueling outage which would allow us to perform the calculations based on that dosimetry prior to this commitment date. So both of those activities are the success path we believe most likely and we're pursuing both of those in parallel.

MEMBER MAYNARD: Those benchmarking

requirements for RAMA, does it have to be plant specific or design specific.

MR. BETHAY: It has to be reactor type.

MEMBER MAYNARD: Reactor type specific. I'll ask the staff that same question.

MR. BETHAY: Yeah, the staff may have some additional comments on that.

MEMBER ARMIJO: Aren't these values essentially extrapolations assuming the core designs will remain pretty much the same. Your reshuffling of the fuel will remain essentially the same strategy?

MR. BETHAY: Yeah, yes, sir.

MEMBER ARMIJO: So if there are changes in core designs or your reload, reshuffling, these numbers would not be --

MR. BETHAY: And we would have to re-perform our pressure temperature curves if that were the case.

MEMBER MAYNARD: Yeah, that would be analyzed and I think that would required to be submitted for approval to the NRC.

MR. BETHAY: That's correct. That's in the tech/specs. It's all -- this analysis leads to the generation of our pressure/temperature curves and that's, you know, part of our operating license, so it's a today operating issue as well as a license renewal issue. Before I get to the summary, if there are no other questions on the fluence calcs, I don't want to leave the fatigue usage factor unaddressed and I don't have any slides on that. The question that came up recently was have we correctly married fatigue -- cumulative fatigue usage factor with environmentally assisted fatigue? We had treated those as separate items, an interaction with the staff over the last month or so, we've revised our commitment for fatigue monitoring program and we've subsumed the environmentally assisted fatigue elements into the elements of the fatigue monitoring program. So the fatigue monitoring program that we have in place addresses those aspects as well and the new program is completely consistent with GALL with no exceptions. So I believe we've identified the correct resolution of how to insure that all aspects of fatigue are properly captured in the fatigue monitoring program.

MEMBER MAYNARD: You just said it but your revised commitment makes you totally consistent with GALL, so with no exceptions.

MR. BETHAY: Yes, sir, that's correct.

CHAIRMAN SHACK: This is Commitment 31.

MR. BETHAY: That's correct.

CHAIRMAN SHACK: Do you have any components currently with a use factor greater than one?

MR. BETHAY: No, we don't.

MEMBER ARMIJO: Even with the --

MR. BETHAY: Even with the environmental UC, we don't have any components that are above one, but obviously we'll continue to monitor that as part of the fatigue monitoring program.

CHAIRMAN SHACK: Is that because you've been doing fatigue monitoring and you're using realistic cycle counts in your analysis rather than some design basis?

MR. BETHAY: Yeah, let me ask Ray. Ray's in charge of that so Ray Pace, our Design Engineering Supervisor.

MR. PACE: Ray Pace, Pilgrim Station. What we have right now is we have a fatigue usage that's less than one on all components. It does not include the environmental portion at this point in time. That is something that we'll start working on next year and we hope to have done by 2010. So we're currently monitoring cycles because all our usage factors are less than one and as long as we don't exceed our cycle counts on any specific transient or event, our usage will remain less than one on all of our components and we don't -- we project that ahead and we don't foresee any problems through the current license period.

MR. BETHAY: Thank you, Ray. And with that, I'll wrap it up and not to use the staff's time.

MEMBER POWERS: Could I ask you, if we could look at Slide 15 just to make it easy, if you could talk to me and subsequently show me in your report where you address the bellows on the downcomers.

MR. BETHAY: The bellows -- actually, the bellows on the downcomer is -- you're talking about the refueling bellows?

MEMBER POWERS: No, the downcomers coming into the suppression pool.

MR. BETHAY: Yeah.

MEMBER POWERS: They have a bellows attachment on it.

MR. BETHAY: Correct.

MEMBER POWERS: Tell me what the status is on those, and show me where they're addressed in --

MR. BETHAY: Where they're physically located on the picture, you can see the --

MEMBER POWERS: Yeah, I know where they're located.

MR. BETHAY: Okay. I'm sorry, can I show you?

MEMBER POWERS: Do I see corrosion on them?

MR. BETHAY: I'm sorry, I don't understand. Go ahead.

MR. COX: They are covered in the pool application, I believe they're in the structural section. Yeah, they're in the structural section and these identify some aging effects that are covered by the IWE program.

MEMBER POWERS: Okay.

MR. COX: We do inspections of those.

MEMBER POWERS: I looked and I didn't immediately find it. So if somebody could just tell me where in the break or something like that, I'd appreciate that. But they're covered in your program and you're handling them. Good.

MEMBER MAYNARD: If there's no other questions for the Applicant, we'll ask the staff to come up. I'll just ask the licensee to stick around.

MR. BETHAY: We'll stick around. Thank you very much.

(Off the record comments.)

MEMBER MAYNARD: For those on the telephone, we're going through a change here to get the slides up for the staff's presentation.

(Off the record comments.)

MS. LUND: Are we all set up, Perry?

MR. BUCKBERG: We're waiting for the brief to be loaded. And I apologize if I delivered it too late yesterday.

MEMBER MAYNARD: All right, I think we have the slides loaded, so Perry, if you'll lead us through the staff's presentation.

MR. BUCKBERG: Good morning. My name is Perry Buckberg. I'm the Project Manager for the staff review for the program license renewal application. Joining me today from Region 1 is Inspection Team Leader Glenn Meyer to my right. Dr. Jim Davis is the Audit Team Leader and in the audience is the technical reviewers. We'll be presenting the results of the staff's review. I'll start by providing some general information regarding the review of the application and then discuss the resolution of the open item related to scoping and screening results, mechanical systems.

Glenn Meyer will then discuss the results of the license renewal inspections. I'll continue and present the open items related to the aging management review and the time limited aging analysis. That's the neutron fluence issue. Displayed is some general information regarding the plant and it's license renewal, you've heard before. The SER was issued just over two months ago. The four open items discussed during the April subcommittee meeting have now been closed by the staff. The SER includes a standard three license conditions for all approved plants and one Pilgrim specific condition related to neutron fluence that we'll discuss later in my brief.

The audits took place in the spring of 2006 and the regional inspections followed last fall. During the scoping and screening methodology audit, the audit team determined there were no emissions of systems or structures within the scope of license renewal. During the mechanical systems review, open item 2.3.3.6 was identified. The applicant included the security diesel system in the scope of license renewal. There was insufficient information in the application to verify exactly what is in the scope. The issue was referred to the regional inspector who verified the applicant's claim on March 9th of 2007, a few days prior to the subcommittee meeting.

We went through the formality, of course, of closing it in the final SER but it was closed at that point basically.

MEMBER MAYNARD: Was the problem that drawings weren't available or that they just had not provided them as part of the application?

MR. BUCKBERG: They hadn't provided them. Let me make sure. They hadn't provided them as part of the application.

MS. GREEN: I'm Kim Green, Nuclear Staff. They had not provided the drawings as part of the application I think for security reasons.

MEMBER MAYNARD: Okay.

MR. BUCKBERG: In conclusion, the staff determined that the applicant's scoping methodology meets the requirements of 10 CFR 54.4. That's it for scoping.

MEMBER MAYNARD: And the applicant discussed scoping. You heard the discussion there and other than a few issues in the beginning, I believe we do not have the Vermont Yankee type of issues. I'd just like to have the staff --

MR. BUCKBERG: Yeah, we had some discussion on that . We verified that that was the case. Pilgrim's approach was different. Pilgrim went through the regional inspection cleaner than Vermont Yankee. Vermont Yankee did have some confirmatory items as part of their draft SER, their SER with open items so to speak and these issues just didn't present themselves for Pilgrim. Scoping and screening was very clear due to the methods that were used and they went right through the process.

Glenn Meyer will present the license renewal inspection portion of today's brief.

MR. MEYER: Good morning. It's nice to see many of you again today after yesterday's Fitzpatrick subcommittee. Next slide. The regional inspection did look at scoping and screening. We reviewed the a(2) part which is the non-safety systems, structures and components. We particularly look at the spacial interaction and also structural interaction. At Pilgrim, there was an issue on structural interaction. They had misinterpreted the drawing symbols as to being a seismic boundary when in fact they weren't, and so there were some re-evaluations that they needed to do.

They agreed to do that and I came back a few months later to confirm that the work had been done properly. So overall, we felt that the scoping and screening was acceptable. As a footnote on the

Vermont Yankee problem, when I raised the issue about the turbine building at Vermont Yankee, one of the first things they did was call Pilgrim and they were rather surprised to hear that, "Oh, yes, Pilgrim had included the turbine building". So the same issue didn't exist at Pilgrim.

Next slide. In addition to scoping, we also look at the aging management programs. We reviewed approximately two-thirds of the programs, looking at the procedures, talking to the people involved, looking at the records for existing programs to get a sense of, you know, what assurance there is that the programs are going to be effective.

Next slide. We did identify a handful of areas that they needed to change the aging management programs and they did agree to do that. And the changes were noted in a license renewal application amendment. Basically, the two issues of the inspection were the structural interaction part that I eluded to and also concerns about the drywell shell monitoring in that Pilgrim has covered the many reasons why they believe that the drywell shell monitoring proposed in the application, which basically did not involve -- did not have ultrasonic inspection of the shell in the period of extended operation, other than some existing plans in the upper part of the shell, we didn't believe were sufficient to address the monitoring.

We couldn't show that their arguments were wrong but they were certainly not completely convincing and they did subsequently agree to do that monitoring that they'd agreed to which we believe is appropriate. Next slide.

VICE CHAIR BONACA: Just a question I had yesterday, you mentioned that you're sharing your experience with the other regions.

MR. MEYER: Yes, as I mentioned, next week I'll be going to Wolf Creek to participate in the Region 4 inspection there and in the scoping area, since there's a split between headquarters, that they do the safety-related part and also the regulatory requirements, fire protection, station blackout and things like that, and we do the non-safety related part. It makes sense to work together and so for example, on Indian Point, I'll be joining the headquarters people when they do their scoping so that we can share our, you know, expertise a little better.

VICE CHAIR BONACA: Thank you.

MR. MEYER: As to current performance of Pilgrim, they're currently in the licensee response column, column 1, the lowest level of oversight, based on having all green performance indicators and findings that are also green. The most recent mid-cycle assessment did not identify any cross-cutting issues. And next slide.

So as I indicated the performance indicators are green. Next, and the findings are minimal and of a low safety significance. And that completes my presentation, if there would be any questions.

MEMBER ARMIJO: I have a question. You said you reviewed 26 of the aging management programs that the licensee presented, identified 40 programs. Who reviewed the balance of those programs?

MR. MEYER: Audit -- the aging management program and aging management review audits look at all the programs. Since we do the field part for, you know, operating experience reviews, the records of -- one of the areas we particularly probe is the previously identified problems, things that would have been put in their corrective action program to get a sense of are they identifying problems related to aging? Are they addressing they appropriately? Do they have, you know, proper programs and procedures to do that?

So ours is a sampling where we do address roughly two-thirds but we're not -- the program doesn't insist that we look at all of the programs.

MS. LUND: Can I make a comment, too? This is Louise Lund. That the next inspection that is done prior to the period of extended operation, the priority is looking at any program that, of course, has been you know, enhanced or any program that has not been inspected before that time. So there has actually been some discussions in meetings where we've discussed the 71.0.0.0 inspection procedure and what that will contain.

MEMBER MAYNARD: Yeah, a number of these programs are programs that were already in place and have been inspected under other programs I would assume.

MR. MEYER: Right, yeah.

MR. CHAN: Ken Chan, I'd like to put some additional comments in this area. The approach we apply to every plant is the same. The audit team audit 100 percent of the AMPs, okay, make sure that the enhancement they put in there is sufficient to bring this AMP to be consistent with GALL. But how do we verify the applicant does that does not require to be on a hundred percent basis. So that's the inspection teams are doing, to verify -- 26 out of 40 is a big percentage, to verify they are doing the right things.

MEMBER ARMIJO: I just wanted to know why, you know, why there was just 26 and --

MR. CHAN: We reviewed -- at the site we reviewed the implementation procedure on selected basis, like one or two per person.

MR. MEYER: We actually had a fairly large team of inspectors that you know, that enable us to do the two-thirds. You wouldn't necessarily do quite that many.

MEMBER MAYNARD: I would also assume that you have flexibility depending on what you find, it can be expanded or whatever.

MR. MEYER: Uh-huh, the inspection process also we take advantage of the expertise that we have on the team. I mean, I think I mentioned yesterday, we have one inspector that's very knowledgeable in the in-services inspection area and he has inspected the drywell and torus at Pilgrim and then followed that at Vermont Yankee and followed that at Fitzpatrick and also he will be speaking at -- testifying at the hearing for Oyster Creek. So depending on expertise, that also influences the programs.

MEMBER ARMIJO: Now, since your latest inspection was done in December of '06, you obviously, did not have a chance to verify the source of the groundwater seepage that the applicant was talking about.

MR. MEYER: True. I will say our drywell expert goes in and did raise issues about the groundwater and how they could demonstrate that it was groundwater and not associated with any leakage from the drywell. So that's what basically got the ball rolling. We did look at all that. It was headquarters that basically followed up on the structural aspects and effects on the concrete and the structure.

MEMBER ARMIJO: Are there any plans to verify what the applicant has just told us about the source and the slow leakage rate at the end of the current cycle in April or May of '09?

MR. MEYER: Our commitments inspection goes in prior to the period of extended operation and we do look at the commitments they've made. I would expect this might be something we would look at. We do have resident inspectors that periodically review various parts of the plant. And so the torus room would be one thing that they would pursue. I don't sense that, you know, going in and verifying the flow rate is something that's crucial but I think we'll probably take a look.

MEMBER MAYNARD: I was going to ask, I'm assuming that when the licensee, when the applicant went in and did some of their recent inspections that some of the regional inspectors or the resident inspector was probably following parts of that at least.

MR. CHAN: To supplement the response in this area, the audit team, we have a structural engineer with the team, and the structural engineer can make a request to go into the torus area, to walk down, and for the plan we discussed yesterday, he told me that he did but I did not sure whether he did it for this plant but it doesn't meet, he would request to arrange a tour in the torus area. So it could be double coverage in connection with the inspection team.

MR. KUO: This is P.T. Kuo. Just perhaps, I can provide some clarification as to what function is being performed and by whom. There is certainly and overlap between the headquarter's staff technical review and the regional staff, the inspection kind of activities. But primarily the headquarter's staff will perform technical review, that adequacy of certain programs that's being performed by the headquarter's staff. And then the regional staff is going out to make sure that all the supporting evidence that the headquarters staff relied on is true, is correct and the implementation of this programs that were proposed by the applicant, are in correct form and adequately implemented. So these are the divisions of responsibility between the headquarters and the regional staff. There are certain overlaps but these are the main functions between the two groups of the staff.

And in terms of a license renewal inspection, during our review we have inspection procedures 71002 that governs that what the regional staff is going to look at and then as far as their commitments are concerned, during the review when we -- and they made a number of commitments. Before the plant goes into the extended year period of operation, there's another inspection that the region's staff are going to do. And that is governed by the inspection procedure 71003. And that procedure has been -- was issued before but it is now going under revision, try to clarify even more between what the procedures are going to take. And this involves the effort between the regional staff and headquarters staff.

And the draft has been issued and we are planning to have a workshop, a meeting sort of, with industry and any public citizen that are interested in and so that -- you know, before we can finalize the inspection procedure 71003.

MEMBER MAYNARD: At some point in the staff's presentation, we're talking about the overall scoping and the aging management program -- I would like to have a specific discussion by the staff for the groundwater intrusion as to --

MR. BUCKBERG: That's coming.

MEMBER MAYNARD: -- why does the staff feel that it's acceptable. So as long as that's coming, that's fine.

MR. BUCKBERG: I'm Perry Buckberg, and I'll continue with open items relating to aging management review and time limit aging analysis. First, open item 3.0.3.2.10 that was discussed earlier by the applicant, addressed the method the applicant would use to inspect inaccessible seals. The applicant has since stated and documented that all seals are accessible and are included in the inspection program.

The second AMR open item dealt with the

staff's request that the applicant address the three observations listed that resulted from the regional inspection. This is what we've been discussing. The applicant did address the staff's concern regarding the possibility of water leaking onto the drywell shell by addressing the failed switches. They provided UT data and committed to obtain additional UT data and identify during that process, the groundwater was the source.

The findings became an open item. Based on the staff's unresolved concern that the torus structure could be effected by the water intrusion, the groundwater intrusion. The applicant has since delivered to the staff the base mat evaluation and has made commitments to evaluate groundwater in torus, bolts and grout. Recently inspected bolts and grout revealed on degradation. The staff concluded that the water intrusion has not been detrimental to the torus structure and that the torus water intrusion will be adequately monitored. The staff felt concerns documented and this open item resolved. Any questions on that issue?

Moving on to licensing renewal application Section 4, time limited aging analysis. The six listed TLAAs to not be accepted as originally evaluated to the unacceptable fluence calculation. The applicant's calculations were deemed not acceptable by the staff because the only available dosimetry sample was not acceptable as a benchmark. This became open Item 4.2.

MEMBER CORRADINI: Just for my own information, it was not considered acceptable because it is in the wrong physical location, it was the wrong type of sample? Why was it not acceptable?

MR. LOIS: This is Ambrose Lois, systems. The original capsule that was removed at the end of cycle 4. It was analyzed by Southwest Research Institute. That was about more than 10 years ago. The results were non-conclusive in the sense that the measured value did not agree with the calculated valued. The applicant submitted that in connection with their (indiscernible) if I remember correctly. And we told them that we did not -- this was not acceptable. We had problems both with the measurement as well as the calculated methodology used by Southwest Research Institute.

Subsequently the licensee did not remove another capsule. They did not have to per Appendix H of 10 CFR.

MEMBER CORRADINI: They did not or --

MR. LOIS: They did not have to, did not have to. When the license extension submittal came around, they resubmitted the original analysis for that capsule, Number 4, Cycle 4, along with two analyses performed by GE and Tanzwell Enterprises which were the author of another new code which was recently approved of RAMA. Both of those analyses drew the same conclusion, namely they will not agree with analysis with measurement. So we told the licensee that this was not an acceptable way of doing that. That's how this thing came about.

MR. BUCKBERG: Thanks, Ambrose.

MR. LOIS: Thank you.

MR. BUCKBERG: To resolve the open ended 4.2, the applicant identified the limiting TLAA and the corresponding allowable neutron fluence. The applicant will, in accordance with the license condition and commitments, complete an updated neutron fluence evaluation and submit it for staff review and approval prior to entering the period of extended operation. The staff will confirm that all neutron fluence criteria associated with the identified TLAAs have been met based on this updated applicant neutron fluence calculation. That's the course of action.

We imposed license condition 4.2.6 which in summary includes that on or before June 8th of 2010 the applicant will submit correctly benchmarked neutron fluence calculations that will confirm neutron fluence at the actual weld will not reach the limiting value by the end of the period of extended operation and that's the value of 3.37 times 10^{18}.

MEMBER MAYNARD: As I recall from the subcommittee meeting, the staff had agreed that even using the most conservative numbers, there wasn't any real safety concern but we needed to complete the benchmarking and do it to get an analysis of record that meets the requirements and that once that's done, it would be compared back to the results to make sure the conclusions were right to start with.

MR. BUCKBERG: Right, it seems that based on what we know about the plant's operation and past submittals of neutron fluence information, they're not close now. There's not a safety issue but what has to be done before license renewal is going to stand and that's why we came to this conclusion.

MR. LOIS: May I add to that, that the two paths of result in this issue that was described with the licensee was recent. We agreed to that and both have the potential of resolving this issue, i.e. the analysis with the new capsule that they are removing or accurately measuring the location of one of the existing capsules and the removing it and measuring their own capsule. Either one will resolve this issue.

MR. KUO: And what -- the statement you just made is correct.

MR. BUCKBERG: What Ambrose is referring to deals with commitment 47, the applicant committed to and has since provided an acceptable action plan to improve the benchmarking data. The CUF issue, in response to the most recent RAI, in an August 28th letter, the applicant removed the fatigue monitoring program exception regarding environmentally assisted fatigue and the result is a fatigue monitoring program that's now consistent with GALL and currently the staff is -- the staff's response is in the supplemental SER which is being drafted and produced as we speak.

MR. CHAN: Ken Chan. In this area, I'd like to provide some additional comments or clarification to one of the questions being answered by the applicant early, like 20 minutes ago. Everyone know that the Pilgrim is one of the old vintage BWR defined in the 6260. 6260 select those locations, six or seven, for further evaluation for EAF for

Environmental Assistance Fatigue. Among those six or seven locations, some are equipment nozzles, equipment components. Some of them are piping components. What the applicant responded earlier to say all the COF us less than one or that -- I would interpret that as for those equipment components, they have COFs calculated.

So you must provide FEN. You get the FEN adjusted fatigue. That part of the answer is right. For the piping components, there are two or three of the piping components, since the piping is designed to B31.1 code, B31.1 does not require you explicitly address fatigue but implicitly, using allowable stress correction factor of F, up to 7,000 is 1.0. Less -- more than 7,000 that allowable stress goes down.

So that was the way calculated for the original design of the Pilgrim. In the application, they mentioned that since this piping is designed to B31.1 that no fatigue COF is required so therefore, they took the 6260 value and say this is our value and so that's less than one. That's, the staff say, is not acceptable. The 6260 are the -- okay, NUREG CR 6260, that is just a sample calculation for the interpress (phonetic) vendors, GE, Westinghouse, CE. The each take an old vintage plan and new vintage plan. The interpress vendors provide you the data for that plant and you calculate.

The purpose is to select locations of most critical ones, it's not to provide, "Hey, this is the COF value". So take that COF value to represent hey, this is pure one, that's totally unacceptable. So through discussion the applicant and us now finally applicant agree and say, we are going to manage this by aging management, and consider before 2010, they're going to provide re-analysis results to justify that those locations which you don't have COF, will have COF and the COF, after amplified by FEN will be less than one. So the total issue will be closed.

So now, this fatigue monitoring program is handling the EF portion of the TOAA, that's what the mean. So it's based on anticipation that when this analysis is done, it's going to be less than one, it will be acceptable. So that's the clarification I'd like to put on here and that's that we are updating, revising, no supplement the SER which is happening.

MR. BUCKBERG: Thanks, Dr. Chan. On the basis of its review of the LRA the staff determined that the requirements of 10 CFR 54.29(a) have been met. That concludes the staff's presentation. Any questions?

MEMBER MAYNARD: Does anyone have any

questions for the staff? What I'd like to do is just quickly go around the room and see if we have any burning questions or comments before we conclude the meeting here, and Sam, I'll start with you. John, I'll come back to you at the end here, but Sam?

MEMBER ARMIJO: No, I don't have any problem but I think all the issues have been addressed, the open items have been closed in very professional way. I think the staff and the licensee have done a very good job. I don't have anything to say any more.

MEMBER MAYNARD: Okay, Dana?

MEMBER POWERS: I still need to look at Table 3.1.2-1. We'll get back to you about that.

MEMBER MAYNARD: All right, very good. Graham?

MEMBER WALLIS: I agree with Sam.

MEMBER MAYNARD: Mario?

VICE CHAIR BONACA: No further comments.

MEMBER MAYNARD: Sam?

MEMBER ARMIJO: I had one question that I didn't have a chance to ask which is related to the uncertainty in the location of the samples on the calculated values of the fluence.

MR. LOIS: Historically, since I've seen

hundreds of those capsules, historically the location of the capsule is the most critical element for uncertainty and for the calculation. If you don't know it precisely, you really cannot come up with a viable solution to that. There is a need that the fluence in the area of the capsule it changes exponentially.

MEMBER ARMIJO: How well do we know the location of the capsules in this plant?

MR. LOIS: Well, the last meeting we had with the licensee, I asked the same question, namely, "Why don't you remove another capsule to resolve this issue"? The license stated and this is a quotation, "We don't know where they are". I presume what that meant is we don't know it within a fraction of an inch, rather than don't know where they are.

Presumably, they have a plan now to locate the -- to measure the actual location of those capsules not with respect to the downcomer or the water path, rather with respect to the edge or the core. Now, that's not (indiscernible) but I presume they have a way of doing that.

MS. LUND: This is Louise Lund. I also want to add in some discussions that Matt Mitchell, another Branch Chief in DCI and I had with management at Pilgrim is, is they understand the need to have very precise measurements and that's why apparently they didn't get it done last outage but that's why the next outage is where they're going to have a contractor come in and actually make very precise measurements because they understand how necessary it is to get it right and as far as having the correct measurements and Ambrose has talked to them as well. So we've had a number of discussions with them about exactly that topic.

MEMBER MAYNARD: Does the applicant want to make any comments about the location?

MR. PACE: This is Ray Pace, Pilgrim Station. Yes, we do understand that measurement is the big concern. If we pull a capsule or when we pull a capsule next outage, we have been talking with our NSSS vendor about getting a precise measurement from the center of the core to the capsule. It is not easy to do. The vendor has come up with a few methods and we'll be pursuing that over the next few months.

The measurement has to be very accurate. We're looking for something that's on the range of an inch and half discrepancy that would cause the bias problem that we've had to date.

MEMBER MAYNARD: Mike?

MEMBER CORRADINI: No.

MEMBER MAYNARD: George, any comments or questions?

MEMBER APOSTOLAKIS: (No audible response)

MEMBER MAYNARD: Okay, John?

MEMBER STETKAR: Nothing further.

MEMBER MAYNARD: Okay.

MS. LUND: Dr. Maynard?

MEMBER MAYNARD: Yes?

MS. LUND: I just wanted to say too, that the context of -- this is Louise Lund -- the supplemental report is to reflect the fact that they have made that -- the fatigue monitoring program consistent with GALL. Basically, it's taking away the exceptions. So that's really the context of why we're doing a supplement because there is a change to that program and that's what you can expect to see.

MR. BUCKBERG: We'll issue the supplemental SER. When it's issued, we'll deliver it to you as soon as possible. The text, there's 11 or 12 pages of text that just includes those sections that are effected. It's not a reissue, so it's not very lengthy, but it's taken some time to get it right.

MEMBER MAYNARD: Now, Dana, did you get

the information?

MEMBER POWERS: I did. I got pointed to the location. I just need now to go look at it.

MEMBER MAYNARD: Yeah, okay, very good.

MEMBER POWERS: I mean, they assure me everything is fine. I have trust but we will verify. We will probably solicit photographs.

MEMBER MAYNARD: Well, I have no further questions. I would like to compliment both the staff and the applicant's presentations are well-prepared. They answers the questions that we had and we'll have to deliberate on this and see where we come out but I do appreciate the input from everyone. So with that, I'll turn it back over to you, Mr. Chairman.

CHAIRMAN SHACK: Ahead of schedule. I think we'll break now until 10:45 since we don't want to get ahead of the schedule here as part of the formal meeting, so we have some time.

(A brief recess was taken at 10:11 a.m.)

(On the record at 10:47 a.m.)

CHAIRMAN SHACK: We can come back into session. Our next topic is Revisions to the Standard Review Plan Sections 19.0 and 19.2 and George will be leading us through that.

Dr. APOSTOLAKIS: Thank you, Bill. Yeah,

SRP Section 19, the full title is Probabilistic Risk Assessment and Severe Accident Evaluation for New Reactors and SRP Section 19.2 is Review of Risk Information used to Support Permanent Changes to a Plant's Licensing Basis. I understand both of these chapters have already been published.

MR. STUTZKE: That's correct.

MEMBER APOSTOLAKIS: Last August I believe or somewhere there. And this is really a briefing to inform the ACRS what the content is and maybe get some comments back from us. It's not clear whether we will write a letter or not. We have to decide that later. The SRP Section 19.0 is a companion to the Regulatory Guide 1.206 which contains the guidance and the content of COL applications and that guide we reviewed back in December of '06.

My understanding is that there is still an issue between the industry and the staff regarding these two chapters and I have here part of the transcript from a meeting on August 22nd of this year between the Commission and the industry where Mr. David Christian, Senior Vice President and Chief Nuclear Officer of Dominion, said that, "The new guidance on PRAs for new plants requires the use of large release frequencies as opposed to larger early release frequencies.

The NRC guidance and all existing PRA applications for operating plants use large early release frequency and the process for reaching a common understanding on that took a number of years and we think that might also be the case for large release frequency." So they are concerned that there is no common understanding of what the large release frequency is and they have this past experience that it took awhile to understand that large early release. So maybe we can discuss that a little bit.

Also, my favorite topic in this area is how much of the PRA am I going to see or do I have to fly someplace where there is no running water to read the PRA.

MEMBER CORRADINI: But the plant is safe there.

MEMBER APOSTOLAKIS: Without any water. So, without any further ado, I'll turn it over to Marty or somebody else?

MS. MROWCA: Somebody else.

MEMBER APOSTOLAKIS: Somebody else, Lynn?

MS. MROWCA: Mrowca.

MEMBER APOSTOLAKIS: Mrowca.

MS. MROWCA: Yes. I wanted to start this

off. I'm one of the PRA Branch Chiefs in the Office of New Reactors and before Marty starts, I just wanted to say that Marty put in a lot of time on this along with Donnie Harrison at the beginning of the year and in fact, Marty will soon receive an employee of the month award in the Office of New Reactors for his work on this subject.

Also, Marty has been recognized and is actually now in the Office of Research. He got a promotion to Senior Level Service. So he's doing this as one of his transitional activities. So --

MEMBER APOSTOLAKIS: I thought he was doing it because he loved the ACRS.

MR. STUTZKE: That too, that too, George.

MEMBER APOSTOLAKIS: That's it?

MR. STUTZKE: Well, when I talked to Dave, Dave said this was my last hurrah. I hope it's not the last one.

MEMBER APOSTOLAKIS: We should give you a hard time then.

MR. STUTZKE: You will anyway.

(Off the record comments)

MEMBER APOSTOLAKIS: Anything else, Lynn?

MS. MROWCA: Did you want -- before we start into the presentation, Mark Ruben has some comments on LERF and LRF. We do address it later, if you want to table that or do you want his comments now?

MEMBER APOSTOLAKIS: Is it part of your presentation, Marty?

MR. STUTZKE: A brief part.

MEMBER APOSTOLAKIS: We'll wait. Is that okay, Mark or are you dying to speak?

MR. RUBEN: Never.

MEMBER APOSTOLAKIS: You are projected on four screens. Isn't that something?

MR. STUTZKE: You're doing this just to disorient me again. For the record, I'm Marty Stutzke. I'm the Senior Technical Advisor for PRA Technologies for Operating Events and PRA in the Division of Risk Assessment and Special Projects in the Office of Regulatory Research. I work for Pat Baronowski (phonetic) now.

MEMBER APOSTOLAKIS: Okay.

MR. STUTZKE: So I'm certain that I will have plenty of opportunities to see the committee again.

MEMBER APOSTOLAKIS: That would be a pleasure, Marty, that would be pleasure.

MR. STUTZKE: So as a brief outline here, I'll give you a little background on the evolution of this Standard Review Plan chapter, briefly touch on the applicable regulations, a time line how the staff envisions the design or combined license applications will be processed, there's some renumbering which can be confusing to users of the new guidance. We'll talk about PRA scope, level of detail, the PRA documentation, briefly on the revisions to SRP Section 19.2, and then the ongoing clarifications since we've published these documents.

So back in September of last year, DG-1145 which was the draft version of Reg Guide 1.206 was issued for comment. The PRA information at that time that had been developed by NRR, at the time NRO didn't exist. Roughly in October then NRO was established. Towards the end of October, in fact, on Halloween, the staff issued a SECY paper of 6.02.20 that were revisions to the proposed rulemaking on Part 52.

In particular, those revisions deleted the requirement to submit the PRA. We'll talk about that. And December 12^{th}, as George had mentioned, you guys reviewed it and issued a letter that recommended that the PRA should be submitted. Come along February of this year the two PRA branches were actually established and NRO. We took over the work roughly in

April.

MEMBER APOSTOLAKIS: Two PRA branches.

MR. STUTZKE: Right.

MEMBER APOSTOLAKIS: I'm sure they have different missions.

MR. STUTZKE: One is devoted towards PWRs and the other is BWRs. About the time that --

MEMBER APOSTOLAKIS: What will happen to the PBMR?

MR. STUTZKE: Right now the PBMR is under Lynn's branch. I think I've successfully offloaded that one. That remains to be seen.

MEMBER APOSTOLAKIS: All right.

CHAIRMAN SHACK: You won't get to work on a technology-neutral framework.

MR. STUTZKE: That remains to be seen.

MEMBER APOSTOLAKIS: Keep going, keep going.

MR. STUTZKE: I count my blessings every evening. So at about the time that I had transferred over to NRO in April the Commission issued the SRM on the SECY paper that agreed with the staff's position that we don't need to submit the PRO. So at that time we had to start making numerous revisions to DG-1145, culminating in the end of June. We issued the reg guide and the SRP sections. Just so you know, the revised Part 52 was issued last week, August 28th.

Okay, briefly, the applicable regulations, in 10 CFR 52.47(a)(27) it states that, "The final safety analysis report of a design certification must contain", and I quote, "a description of the design specific PRA and its results". See similar language under 52.49(a)(46) which applies to combined licenses. This additional regulatory basis here depending on whether you're talking about a design approval or a certification or one of the manufacturers, the language is roughly the same.

Let's look at the second bullet, 52.79(d)(1), says, "If the COL applications references a standard design certification, that PRA must use the PRA submitted for the design cert and it must be updated to account for site specific design information and any design changes and departures". Now, the Commission added one more thing. For holders of a combined license, not applicants, but now --

MEMBER APOSTOLAKIS: Excuse me, COL is combined license, construction license or construction and operation license?

MR. STUTZKE: Combined license.

MEMBER APOSTOLAKIS: That's the official

interpretation?

MR. STUTZKE: That's the official interpretation.

MEMBER APOSTOLAKIS: Okay, thank you.

MR. STUTZKE: When I got into the business they used to say COL stood for combined operating license, but the correct language is combined license.

MEMBER APOSTOLAKIS: Okay, that's good.

MR. STUTZKE: But we still use the COL acronym.

MEMBER APOSTOLAKIS: Good.

MR. STUTZKE: But there are the requirements now for living PRA.

VICE CHAIR BONACA: Including license renewal.

MR. STUTZKE: Including license renewal. Okay, and I point you to 10 CFR 50.71, that generally talks about updates of the FSAR. So subparagraph (h)(1) says, "No later than the date of initial fuel loading. Each holder of the combined license shall develop a Level 1, Level 2 PRA and it must cover the initiating events and modes, operating modes for which NRC endorsed consensus standards on PRA exists one year prior to the scheduled date of the fuel load."

Subparagraph (h)(2) says, "The holder of the combined license shall maintain and upgrade the PRA". The statement of considerations for that says, "The definition of PRA maintenance and upgrade is in accordance with the ASME PRA standard, precisely defined and PRA upgrades must occur every four years until the permanent cessations of operations. And finally, (h)(3) says, "Each holder of a combined license no later than the date it submits the application for license renewal must upgrade the PRA to cover all modes and all initiating events".

MEMBER APOSTOLAKIS: The PRA must be upgraded every four years? What if there is a major change in the plant?

MR. STUTZKE: Well, it would be updated in accordance with the ASME standard, which is normally every two years. In addition, you need to realize there are other requirements for updating the FSAR in 50.71, okay, and that's every two years.

MEMBER APOSTOLAKIS: So what's the purpose of the four years?

MALE PARTICIPANT: It's no more than.

MR. STUTZKE: It's operational data.

MEMBER APOSTOLAKIS: It says every four years. It doesn't say at least or at most. But you're saying there are other regulations that will force --

MR. STUTZKE: Require a more frequent updating. That's part of a normal FSAR update process.

MEMBER WALLIS: What's the definition of a living PRA as opposed to one that says half a life. If it's not operated and something significant happens then --

MEMBER APOSTOLAKIS: Every two years, updating every two years makes it living, right?

MEMBER WALLIS: But if there's a significant change in the plant, you've got to upgrade the --

MEMBER APOSTOLAKIS: Or if there is a change.

MR. STUTZKE: Right, we'll talk about it a little bit later but basically the --

MR. HAMZI: Marty, can I just make a comment. This is Hossein Hamzi. I think maybe Marty forgot to mention that there's an upgrade and update. There's a difference between the two. Upgrade is if you want to expand the scope. For instance if you did not have external events and at some point you want to add those because you have more information and the Commission has directed us to do the upgrade every four years. Now the update is consistent with the ASME guidelines and that's what you're talking about. That if you have data, more data, more operational experience, then that is consistent with ASME guidelines. Is that right, Marty?

MR. STUTZKE: That's right. It's in the next view graph.

MEMBER APOSTOLAKIS: When a license is granted, they're supposed to have a complete PRA?

MR. HAMZI: Correct.

CHAIRMAN SHACK: Only if you have consensus standards.

MEMBER APOSTOLAKIS: See, that's another question. No, it didn't say that, only. That's a question --

CHAIRMAN SHACK: Those loads for which a consensus standards exist one year prior to scheduled date.

MEMBER APOSTOLAKIS: Where is that, where is that?

CHAIRMAN SHACK: (h)(1).

MR. STUTZKE: I'll try to clarify that.

MEMBER APOSTOLAKIS: But it doesn't mean only those.

CHAIRMAN SHACK: Well, it must cover.

MEMBER APOSTOLAKIS: It must cover. There may be others. The thing is --

MR. STUTZKE: I interpret (h)(2) to mean that if you come up with consensus standards for seismic, shutdown, fire, you then upgrade to include those.

CHAIRMAN SHACK: That's correct.

MEMBER APOSTOLAKIS: That's considered an upgrade.

MR. HAMZI: Correct. There is a difference between upgrade and update and I believe Marty is going to cover in more detail in the upcoming slides.

MEMBER APOSTOLAKIS: But it doesn't really sound too good to say that for a plant that may be around for 60 years, the PRA will be upgraded 60 divided by four, what 15 times. I mean, that's really pretty bad. Updated is okay, but not upgraded 15 times. I was hoping that we would have a fairly complete PRA --

MR. STUTZKE: Let me try to explain a little bit. The ASME standard defines the terms "maintenance" and "upgrade". Maintenance refers to updating the PRA to handle plant modifications. So if they add a new system or new pump, new operational data, that is maintenance of a PRA. Upgrading a PRA refers to improving the methodologies. So if they adopt for example, a human reliability method or a software platform.

MEMBER CORRADINI: So it could be a change in scope or a change in method.

MR. STUTZKE: Right. That's an upgrade.

MEMBER APOSTOLAKIS: So update, according to what I just heard from you and Mark and Hossein, update means you collect additional data so you update your distributions, you know, that kind of thing. Upgrade means I go into the methods.

MR. STUTZKE: That's correct.

MEMBER APOSTOLAKIS: You know, I was using something before but now I will use the best available model like ATHEANA.

MR. STUTZKE: Let me try to explain this a little bit better. I drew up this time line here.

MEMBER APOSTOLAKIS: I'm glad the other new member is not here. (Laughter)

MEMBER STETKAR: Which at times is a good thing.

MR. STUTZKE: Okay, roughly, if you look at how the plant is built and constructed. There's five distinct time phases; the preparation of the application, the staff's review of the application including the hearings. At that time the combined license is actually issued and utilities would start the actual construction.

MEMBER APOSTOLAKIS: So that's another thing. Unless the COL is approved, they cannot start doing anything on the site? That's a side comment.

MR. STUTZKE: Some limited work off the site.

MEMBER CORRADINI: It's their own nickel, their own liability.

MEMBER APOSTOLAKIS: But they can start digging dirt and --

MR. STUTZKE: Some things. I'm not an expert but it's like --

MEMBER APOSTOLAKIS: No, I was just curious.

MR. STUTZKE: They can't excavate the foundation.

MEMBER APOSTOLAKIS: They cannot what?

MR. STUTZKE: Excavate a foundation.

MEMBER APOSTOLAKIS: Why not?

CHAIRMAN SHACK: Because the law says they can't.

MEMBER APOSTOLAKIS: It's not approved,

it's their own money.

MR. STUTZKE: Anyway --

MEMBER APOSTOLAKIS: You guys have lived with regulations for too long. If I want to dig a hole, why can't I do that, without any nuclear materials? By anyway, keep going.

MR. STUTZKE: Okay, the middle part of the figure points out something that seems to be a source fo confusion. It was certainly confusing to us while we were developing it. And that is up until the time the COL was issued, you are an applicant. So your comments on PRA upgrade, update, maintenance, don't apply because you don't hold the license. Okay, Part 50 applies to holders of the COL not applicants of the COL.

Part 52 doesn't speak at all about these standards. It just says a description of the PRA and its results. Okay, once you actually have that license in your hand, you become a holder and then you're subject to Part 50 requirements. So the way that this works is I've given you some examples, we'll call them Standard A and Standard B. Standard A would be developed at some time and the NRC would endorse it more than one year prior to the initial fueling load and at that point in time that standard would be expected to comply with them.

On the other hand, we have a Standard B here where we don't get around to endorsing it within that one-year time window and you would not be expected to comply with that. The reality of the situation is like this --

MEMBER CORRADINI: Can I just make sure I understood your example? So your point is, let's say off or non-power -- a non-power standard for PRA wouldn't be organized and approved within that year time window, that would be equivalent of B; whereas internal events would be A.

MR. STUTZKE: But realize four years later then we would upgrade or shutdown PRA requirements.

MEMBER CORRADINI: Sure, right, right.

MR. STUTZKE: But the reality of the situation is like this, I've discussed it with Mary Druin and realized that AMSE and ANS are developing what's called a combined PRA standard, so they've merged in the full power internal events standard with the external events and with the fire PRA standard. Okay, and that standard, combined standard, is due to be issued in December of '07. It's going up for balloting, final balloting, in the next couple of weeks.

MEMBER APOSTOLAKIS: Excuse me, that's power?

MR. STUTZKE: Full power, Level 1, Level 2, internal and external events.

MEMBER APOSTOLAKIS: Okay, so shutdown is completed outside.

MR. STUTZKE: Shutdown is later. And the staff will review those and endorse them in a Revision 2 to Reg Guide 1.200 and that's --

MEMBER APOSTOLAKIS: They will come here, too, or you hope.

MR. STUTZKE: They will come here. But that endorsement and the issuance of Reg Guide 1.200 is due in December of 2008.

MEMBER APOSTOLAKIS: So we should expect to see it some time in the spring?

MR. STUTZKE: That's correct. But my point is this, is even if we got a combined application today, the staff's review is planned for about 30 months. Then there's some 12 to 14 months of hearings, probably much longer than that and all time standards are being developed and endorsed. Then the utility actually has to build the plant, okay, so we're talking years. And my belief is all the standards will be issued and endorsed before the first plant actually loads its fuel.

MEMBER APOSTOLAKIS: Which is when?

MEMBER CORRADINI: Well, so let me -- can I ask him to retract that question because I like this time line, so I -- in my mind, I put three years on prepare, three years on review, three to five on construction, a year on start-up and then hopefully a whole long time in commercial. Is that approximately?

MR. STUTZKE: That's my understanding.

MEMBER APOSTOLAKIS: Okay, so what's the key element of this slide? That one year prior to initial fuel loading there had to be a living PRA?

MR. STUTZKE: That's correct.

MEMBER APOSTOLAKIS: And that comes back to what Shack mentioned. You know, that -- which is kind of ambiguous. "Must cover those initiating events and most for which NRC successor standards exist". One year prior so two years before the loading. But that doesn't -- the regulation does not limit the PRA to those. It says if you're going to do internal events, hey, we have a standard, you'd better follow it. But if you're going to do a crazy new event, then do the best you can and we'll review it. That's really what this means. That's the way I understand it.

And then if later somebody develops a standard, you go back and upgrade or whatever you need to do. So the point of having the PRA one year prior to the initial fuel loading is --

MS. MROWCA: Excuse me, at fuel load.

MEMBER APOSTOLAKIS: At fuel load, so what does the year prior means?

MR. STUTZKE: That's the window that determines which standards would apply and which don't apply.

MEMBER APOSTOLAKIS: Oh, the standards, okay, yeah. What is the purpose of that?

MR. STUTZKE: It's a grace period.

MEMBER CORRADINI: You know, you can't keep ratcheting up right up to the legalized minute.

MR. STUTZKE: Right.

MEMBER APOSTOLAKIS: Why do you want a living PRA at the beginning, I mean, just to have a model of the plant and you plan to use it --

MR. STUTZKE: That's when the risk begins. That's when the fuel is actually present in the core.

MEMBER CORRADINI: Well, from a timing standpoint with the earliest application, unless I missed my math, we're talking 2012, 2013.

MR. STUTZKE: That's correct. And all the standards will be well in place.

MEMBER CORRADINI: Well, in place, that's correct.

MEMBER APOSTOLAKIS: Will it have all the standards we require for a PRA? Is that the statement?

CHAIRMAN SHACK: At least the first cut, yeah. But under Part 52, they'd have to have a full scope PRA anyway. They just don't have to meet the standards under Part 52.

MR. STUTZKE: That's correct.

CHAIRMAN SHACK: So even if the standards weren't in place, you'd still have external events. You'd have fire. You'd have all this, it just wouldn't meet the standards.

MEMBER APOSTOLAKIS: So this is Part 50.71 that asks them to do the standards.

MR. STUTZKE: Yeah.

VICE CHAIR BONACA: And that would be living PRA ahead of time would allow you to evaluate all the ascension programs.

MEMBER APOSTOLAKIS: All the which programs?

CHAIRMAN SHACK: Ascension, power ascension.

VICE CHAIR BONACA: Power ascension.

MR. STUTZKE: I have some more view graphs a little bit later will try to clarify. Briefly the sections, the SRP sections have been renumbered. What we used to call -- well, this new Section 19.0 which talks about combined licenses is a brand new section of the SRP and it supports or it's the counterpart for the Reg Guide 1.206. There's two pieces in it, Section C.1.19 that talks about applications that are not based on a design cert. Section C.3.1 talks about applications that are based on a design certification and this Chapter 19 that talks about how you should incorporate that design certification PRA, adapt it to make it plant specific. The old Chapter 19.1 has been relabeled as Section 19.1 and it talks about technical adequacy. It's linked to Reg Guide 1.200. What we used to call SRP Chapter 19 is now SRP Section 19.2 and it's linked to Reg Guide 1.174.

Okay, the scope of the PRA for the application as specified in our regulatory guidance says Level 1 and Level 2 PRAs all initiating events, internals, externals, all operating modes, full power, shutdown, low power, and the lack of standards doesn't reduce the scope. Staff has always had this position since we've come out with risk informed regulation, all initiators, all modes. We're not deviating from that. So to answer George's question before is that the idea of the consensus standard is that if it's one way to demonstrate technical adequacy and if an applicant follows that, it reduces the amount of review that we need to do. But if they don't follow it, they do some crazy thing, then we'll review it.

MEMBER APOSTOLAKIS: But unfortunately, they may still request changes following the deterministic regulations, right? This is all optional.

MR. RUBEN: It's not optional.

MR. STUTZKE: It's not?

MR. RUBEN: No, this is part of Regulation Part 52 that there be a PRA that reflects the as built plant that's going to operated at fuel load. This is not optional. They can pursue deterministic approach for plant changes.

MEMBER APOSTOLAKIS: Yes.

MR. RUBEN: Right.

MEMBER APOSTOLAKIS: That's what I'm saying. They can still do that.

MR. RUBEN: Right, but there are some policy guidance from the Commission on risk metrics that must be met and that is an overarching set of criteria.

MEMBER APOSTOLAKIS: The dual regulatory system is extended into the future in the sense that if I -- I want to build a reactor. You want me to have a PRA, I'll do a PRA, but I'm going to have it in the desk and if you want to look at it, come, but I will never use it. I can still operate, right?

MR. RUBEN: Yes.

CHAIRMAN SHACK: If you keep updating and maintaining it.

MEMBER APOSTOLAKIS: Yeah, because you asked me to and I keep some guys gainfully employed, that's great, but I will never use it.

MR. STUTZKE: But I wouldn't infer that for a combined license that every license amendment is a risk informed license amendment.

MEMBER APOSTOLAKIS: No, it's not.

MR. HAMZI: Marty, let me just add one more clarification, George. There are rule requirements that says you have to complete a PRA at the design certification phase and one at the COL phase.

MEMBER APOSTOLAKIS: Right.

MR. HAMZI: And then there are regulatory requirements as to how often to update your PRA and how often to upgrade it.

MEMBER APOSTOLAKIS: Yeah.

MR. HAMZI: Now, but it doesn't tell you you have to use it for some of the regulatory applications. If you do decide to use them for regulatory applications, then there are, as Mark said, already things in place that they have to follow. Now, as part of the COL application, they can come back and say, "We would like to use our PRAs for the following applications". They can identify, "For instance, I would like to use 50.69. I want to use it for this and that, and then based on those, they have to make sure that the scope and quality of the PRA satisfies those -- satisfies the requirements for those specific applications.

MEMBER APOSTOLAKIS: But my point is that they can also decide not to use it at all.

MR. HAMZI: That's their choice. However, they have to maintain it and operate it.

MEMBER APOSTOLAKIS: No, I understand the rest. My problem is that we're perpetuating this dual -- so-called dual system. That has been settled. The Commission has decided, so le's go on, huh?

MR. RUBEN: I would just also point out that the Commission, though, has established policy requirements based on risk metrics for the Part 52 licensed plants which does --

MEMBER APOSTOLAKIS: Like?

MR. RUBEN: A CDF guideline of 10^{-4}, a containment performance guideline of 10 percent weighted failure per sequence and a light reeler's frequency of 10^{-6} or less. This is from the Commission Advance Reactor Guidance from the 1990s and still applies.

MEMBER APOSTOLAKIS: I can meet those. I have to meet those. All right.

MR. STUTZKE: Okay, so again, the level of detail that we expect the PRA it must reflect the as to be built and as to be operated plant. So one cannot simply just copy the design certification PRA or incorporate it by reference. There needs to be some demonstration that that PRAS has been reviewed and it's been found adequate to make it site specific.

That being so, it may be possible for applicants to rely on bounding analysis so they can do one study that would apply to multiple applications, for example, AP-1000. We are concerned that bounding analyses might mask or distort the important information.

MEMBER CORRADINI: Can you -- you said,

for example, I guess I don't understand the for example. Do you mean that the design cert is bounding enough that a lot of questions or --

MR. STUTZKE: You would demonstrate that you met those risk metrics markered on the --

MEMBER CORRADINI: Right.

MEMBER APOSTOLAKIS: But don't they have to demonstrate also that the bounding analysis is indeed bounding?

MR. STUTZKE: That's the difficult part.

MEMBER APOSTOLAKIS: Sometimes we just -- everybody says it's bounding and you look at admittedly some assumptions are pretty conservative, but there are others that are not that conservative. So and we don't seem to be bothered by it. The document has been published, right?

MS. MROWCA: This is Lynn Mrowca. I just want to say that along with Westinghouse Design Control Document Rev 16 now that's in the house, we also have about 132 or more technical reports and one of them addresses external events.

MEMBER APOSTOLAKIS: Hundred and thirty two what?

MS. MROWCA: Hundred and thirty-two technical reports that rev the designs control document up to Rev 16. That's what we have right now, but one of those reports has to do with external events and the bounding analysis and that's currently under review and we have some requests for additional information that asks similar questions to what you're asking.

MEMBER APOSTOLAKIS: Are these reports ever going to come before us?

MS. MROWCA: That I don't know. That I don't know.

MEMBER APOSTOLAKIS: I would like to see those. I mean, some of those must be very important.

MS. MROWCA: We'll have to pass that onto Projects.

MEMBER APOSTOLAKIS: Well, I think you should coordinate it with the ACRS staff and maybe we can select some that are relevant because I'm sure a lot of them are just routine. Okay.

MR. STUTZKE: With respect to PRA technical adequacies, Reg Guide 1.200 is one acceptable approach to demonstrating adequacies and we would note that all of the NRC endorsed consensus standards require peer reviews. So we are relying on this approach on the use of peer reviews in lieu of a more detailed staff review.

MEMBER APOSTOLAKIS: But you are not precluded from doing that.

MR. STUTZKE: We are not precluded from that.

MEMBER APOSTOLAKIS: Yeah.

MR. STUTZKE: In addition, the standard states that users may need to add or revise requirements to address advances LWRs. In other words, there may not be enough supporting requirements and users of the standards are supposed to revise them like that. Of course, the idea is that meeting the standards should expedite our review and our planning, our scheduling is based on this idea.

This is kind of a fundamental reason why the staff has decided that applicants don't need to submit the PRA in its entirety.

MEMBER CORRADINI: If they meet the standard, if they use --

MR. STUTZKE: That's right.

MEMBER APOSTOLAKIS: But let me -- I mean, there are two questions here. One is do you have any guidance for the staff how to conclude that the PR review that the licensee has conducted is acceptable? In other words, the licensee comes and says, "We use the NEI document, we found a group of peers. They reviewed it. They made comments, here they are, we're going to check". Now you guys will say, "That sounds good to me". Or there will be something more.

MR. STUTZKE: No, we'll add some teeth with it through an RAI process or even an onsite audit.

MEMBER APOSTOLAKIS: So you might select some issues and --

MR. STUTZKE: Absolutely, we'll send a team of people down and have at it.

MEMBER APOSTOLAKIS: The other thing that really worries me -- well, first let me ask -- start with a question. How many of these advanced plans use digital I&C in an integrated fashion in the plant?

MALE PARTICIPANT: All of them.

MEMBER APOSTOLAKIS: All of them. So they actuate safety functions, control. Now, as you know, the state of the art of bringing IS&C -- digital I&C to the PRA is in its infancy. I wonder how one would review a PRA like that.

MR. STUTZKE: For AP 1000 I believe it was done parametrically. You send them the models and they looked at the sensitivity.

MEMBER APOSTOLAKIS: But part of the problem is that we're not even sure that we understand all the failure modes. I thought that was something that could be handled, you know, one way or another, but the more I think about it, the more I'm becoming convinced that this will be a -- the major issue. Is there a way out of it?

MR. STUTZKE: No, I wouldn't disagree with you. I think it introduces substantial modeling uncertainty or completeness uncertainty, however you want to word it.

MEMBER APOSTOLAKIS: Go back and look at some of the incidents with digital systems, now that industry's or our own. You know, some strange things, you know, and I can't --

MR. RUBEN: If I could add, Dr. Apostolakis, this is a very active area for the staff. The risk assessment of the digital I&C systems is not the end all of the issue. Rather, there is a digital I&C steering committee. There's a lot of work going on with industry to help develop the methodology, but we share the skepticism that you just espoused and that's one of the reasons that from the very beginning we had required diverse actuation RPS to provide the defense-in-depth, given the uncertainty in the modeling capabilities.

MEMBER APOSTOLAKIS: I am aware of these

efforts and we actively involved as well in reviewing that but I don't know -- I mean, and I don't know that the industry or the agency can do any more than what they're already doing, but the fundamental question is, are we going to have the necessary insights in time for the license.

MR. JENKINS: This is Ronaldo Jenkins in the Office of Research. We currently are engaged in a digital I&C risk assessment project, those two basic approaches that are being used and part of the outcome of the project is to identify regulatory guidance both for the staff and for licensees.

MEMBER APOSTOLAKIS: I understand that. And I know the project you're talking about. I'm actually concerned about the actual product that will come up, not necessarily because this project is not run well or anything. I think there is a fundamental problem where. I mean, we can't just say for every problem that exists, we'll establish a research project. We'll have the answer in two years or three years. I think there are some fundamental conceptual problems here that I'm not sure will be resolved and that does not reflect on the people who are doing it. It does not reflect on you or the agency. It's really fundamental. Digital I&C do not behave like physical systems.

And on the other hand, of course, they're being used in space systems and so on but they've had failures there. Okay? And the more I think about it, the more troubled, I guess, I get and I guess you guys are disturbed, too. But that's something we really have to pay attention to.

MR. STUTZKE: I would point out that the PRA is not like other sorts of safety analyses, in that it doesn't have acceptance criteria. It has guidelines. You do the best you can to compute the risk metrics and you compare it to the guideline and you know if it's incomplete.

MEMBER APOSTOLAKIS: And you're right, and I'm not so much worried about the probability. I'm worried about the failure modes.

MR. STUTZKE: Right.

MR. GRIFFIN: In other words, even if I wanted to do this in a deterministic way, traditional way, I mean, you look at what happened at that Bruce Plant in Canada some weird thing. I said, my God, would I have figured that out when I reviewed another plant? I mean, I don't know. Maybe, you know, the diversity and defense in-depth, come up with something that would be at least acceptable. I just wanted that on the record, that this is really something that is not just another issue because passive systems, yeah, I know, we haven't really done much and on but it doesn't worry me that much. We can handle it until we decide we can't.

MEMBER POWERS: Mr. Apostolakis, a question for you on your fundamental concern. Suppose I said there are n digital systems in this world and in this world I've discovered m flaws. So m over n constitutes the frequency of flaws, I put that in my PRA and go.

MEMBER APOSTOLAKIS: No.

MEMBER POWERS: Why not?

MEMBER APOSTOLAKIS: The flaws are not exchangeable, the flaws. There have been four assassinations of US presidents. Okay, what's the probability that this president will be assassinated, four over 238 years? No.

MEMBER POWERS: What's wrong with that?

MEMBER APOSTOLAKIS: You try to walk up in Seattle when President Bush attends a thing and go next to him and try to shoot him, like it happened in 1863 or '4.

MEMBER POWERS: Yeah, but they've got better guns.

MEMBER APOSTOLAKIS: They're not exchangeable events.

MEMBER POWERS: I don't have to get that close any more.

MEMBER APOSTOLAKIS: Well, see, that's the thing, there is huge uncertainty. No, the ratio is not.

MEMBER POWERS: Yeah, I'll admit that I'll put in a nice broad band of uncertainty for you.

MEMBER APOSTOLAKIS: It's not just the probability. That's what I'm saying, it's the weird failure modes that we see here and there and we just can't figure out. The probabilities, I'm willing to live without probabilities for awhile or I can be conservative. But the failure modes is what bothers me. And I think the project that the staff has established as one major task is to understand what has happened and see how that relates to our industry. We'll have --

VICE CHAIR BONACA: Especially in a design in which you are instructing, you know, operators to walk back, step back and let things run. What happens if it's running the wrong way, I mean, because of some I&C controls?

MEMBER APOSTOLAKIS: We need some

assurance there. And I don't think it's a PRA issue. Okay.

MR. STUTZKE: Okay, with respect to documentation on the PRA, the Reg Guide specifies the information to be included in the FSAR and as I've said earlier, we note that combined licenses that are based on the design certification may incorporate information by reference. That's not just unique to the PRA but large sections of combined license applications will incorporate generic DCD by reference.

MEMBER APOSTOLAKIS: So Marty, the statement in 19.0 is, "An applicant's FSAR for both a DC or COL application needs to provide the description of the PRA and its results". My words, without submitting the PRA. What is the definition or the understanding of what the description of the PRA is?

MR. STUTZKE: It's coming up in two slides.

MEMBER APOSTOLAKIS: In two slides, that's a definition.

MR. STUTZKE: The point I'm trying to make here is that the who PRA is available because it needs to be archived in accordance with Reg Guide 1.200 and the ASME standard. And we can certainly go and examine through either the RAI process or on-site audits. It's cumbersome, it could be cumbersome.

MEMBER APOSTOLAKIS: Okay.

MR. STUTZKE: Especially for the pebble bed.

MEMBER APOSTOLAKIS: But I don't know if this is the right forum but okay, I understand that the applicant does not have to submit a PRA, so then it becomes part of the licensing basis, I guess. Can they send it say to the ACRS on a CD?

CHAIRMAN SHACK: I'm sure they can.

MEMBER APOSTOLAKIS: Would they?

CHAIRMAN SHACK: I have no idea.

MALE PARTICIPANT: They're required to.

MEMBER APOSTOLAKIS: No, they are not required to submit it officially to the agency. But I mean, would they expect the ACRS to go to a site and view the PRA?

CHAIRMAN SHACK: I would suspect they would.

MEMBER APOSTOLAKIS: That would be a very annoyed ACRS.

CHAIRMAN SHACK: You'll have an opportunity to find out, perhaps, George.

MEMBER APOSTOLAKIS: I hope I won't

actually.

MEMBER CORRADINI: My understanding is South Texas is beautiful in August.

MEMBER APOSTOLAKIS: It is, yes, 120 degrees or something.

MEMBER CORRADINI: You can hit a hurricane.

MEMBER APOSTOLAKIS: No, but what is the understanding of you guys? You are much more involved in this than we are. Can we just say, you know, "Send us a CD"? And they say, "Okay, sure, here's to Bill Shack". That's not submitting it officially but if that can be done, then that's great. Can't we ask them to come and give a presentation?

MEMBER CORRADINI: I'm sure, yes.

VICE CHAIR BONACA: That's a different thing.

MEMBER CORRADINI: That's a different thing.

MEMBER APOSTOLAKIS: Why? They may ask you to go there and have the presentation. That is a mystery to me how that's going to work. Mark, do you know how it's going to work?

MR. RUBEN: Well, all I can do is speculate and confirm what Marty has pointed out that the regulation does not require the complete PRA. However, the staff has our full safety review and audit responsibilities. We're anticipating site audits as necessary to look at it and in the past, all the advance reactor vendors and designers I think have shown a lot of responsiveness to ACRS' requests for information and presentations. I certainly wouldn't expect that to change.

Whether they'll send you a DVD on -- for the complete PRA or not, I can't speak to.

MEMBER APOSTOLAKIS: They are doing it now, though, for the design certification.

MR. RUBEN: There was a change to Part 52. It is no longer required.

MR. STUTZKE: Okay, so this magic phrase, description of the PRA and its results. In order to write the regulatory guidance on the SRP, we had to define what we meant by a description of a PRA. This list of items here are things we expect applicants to discuss in Chapter 19 of the FSAR, okay, the actual PRA methodology, the identification of specific methods such as ATHEANA, the list of initiating events, the success criteria including the thermal hydraulic components, a description of the accident sequences. I've pointed out to people many times the most efficient way to describe sequences is to give us the event tree plots. That's why the draw the event trees. So it's simpler to do that rather than give me pages and pages of narrative and explanation of sequences.

MEMBER APOSTOLAKIS: Would you want to see all the event trees?

MR. STUTZKE: Yes. We need to see all the event trees if you're interested in the sequences that got chopped off with the answer. It may be in error. A list of all the plant systems and their functions that are modeled in the PRA, the dependency matrix between them. Sources of numerical data, the identification of the software platform and the truncation limit. The reason why this list was crafted the way that it was is, this establishes the overall methodology and therefore, changes to this set of information is an upgrade.

This signal says when upgrades are happening. As far as the results, again, these are the results that we expect to be available in Chapter 19. The high level risk metric, CDF, large release frequency, conditional containment failure probability, description of the significant sequences and their frequencies. Significant is defined as in the ASME TRA standard. I need sequences comprise 95 percent of the total metric or individually one percent.

Industry has been concerned that that could be a large number of sequences in some cases. If you have a flat risk profile, you could have a large number. My answer to that is two-fold. First of all, the definition of what is a significant sequence was done by the industry in their own standard. We just endorsed it. Second of all, it turns out for the AP-1000 this is like 32 sequences. It's not a big body of information. Significant initiating events and their contributions to the overall metrics. These are the classic pie charts that PRA analysts love to show their bosses, what's driving the answer.

Identification of the significant functions, systems structures components, operators' actions, importance measures, assumptions behind the PRA and the insights that were derived from the PRA and finally, the results of sensitivity and uncertainty analysis. So, it's hoped that with these description and these results, we can get to a good understanding of where the risk lies in these new plants.

MEMBER APOSTOLAKIS: Now, the applicant -- does the applicant have any guidance as to what kind of sensitivity analysis the staff expects to see? Surely you don't expect them to start changing everything, one at a time and two at a time and three at a time, so there is something here on page 19.0-8 that talks about sensitivity studies performance to gain insights about the impact of uncertainties or the potential lack of detailed models on the estimated risk.

In other words, are you focusing on model uncertainty --

MR. STUTZKE: Yes.

MEMBER APOSTOLAKIS: -- when there are some doubts?

MR. STUTZKE: The answer, the short answer is there's no guidance now but guidance is being developed by the Office of Research.

MEMBER APOSTOLAKIS: It's being developed, okay. Right, 19.0 leaves it at that. It says, do it. Okay. Then 19.2 becomes a little bit more specific. And then it says, "A reviewist should pay particular attention when the characterization of a modal uncertainty such that the results fall into a bi-modal or multi-modal distribution and one or more of the molds exceed the acceptance guidelines. The results should then be reviewed on the basis of an evaluation of the significance of the hypothesis associated with the modes that exceed the guidelines."

In other words, this -- it's on page 21. It specifically says if you identify an outlier or some number that is unacceptable, then you have to go back and pass judgment on how likely the assumptions that led you to that result are.

MR. STUTZKE: That's correct.

MEMBER APOSTOLAKIS: Which is really the way it should be done. But it's sort of mentioned in passing and I'm not sure -- shouldn't you make it a little bit more -- but that's really the understanding. I'm interpreting it correctly.

MR. STUTZKE: That's right, but I would also say there's additional guidance that's provided in the ASME PRA standard about the need to do uncertainties and sensitivities.

MEMBER APOSTOLAKIS: Yeah, but what it doesn't tell you as I recall is what to do with those sensitivity analysis. It's easy to say do sensitivity but what you do with the results.

MR. STUTZKE: I agree.

MEMBER APOSTOLAKIS: This is the first

time I've seen writing something in an official document that says what you should do about that. And of course, here you can expand now and say okay, you know, you will do an evaluation of the significance of the hypothesis, but what if these hypothesis are controversial? I mean, maybe you do an evaluation. You said it's five but there are a lot of other people who think it's 10. And you're going to go to expert opinions or -- this is kind of open here but it's a good step forward in my view the finally we're saying look, the sensitivity studies show that we may be violating something somewhere, start thinking about how likely that something is.

MR. STUTZKE: I understand.

MEMBER APOSTOLAKIS: I'm pretty sure you're going to need more guidance sometime in the future about this.

MR. STUTZKE: Yeah, I made a note to that point. A little bit later on in the presentation we'll talk about some clarifications to our guidance. We intend to issue interim staff guidance and this may be a candidate to --

MEMBER CORRADINI: Is this the right place to ask what's the different between a LERF and LRF?

MR. STUTZKE: Hang on, that's one of the

clarifications.

MEMBER APOSTOLAKIS: This is Marty. He always has an answer.

MEMBER CORRADINI: Okay.

MR. STUTZKE: Briefly, the revisions to Section 19.2 were very small. We did add references to Reg Guide 1.2 and 1.1 for technical adequacy. I think some interesting rewording directed by the Office of the General Counsel and some typos, but the substantive, you know, information is as it always has been, like this.

Okay, clarifications. Since we issued the Reg Guide and the SRP in the end of June, we have had three public meetings to discuss them, well-attended by respective applicants, well-attended, like we had 70 people at one meeting. During the meeting we identified, began to identify what we call frequently asked questions, a list of issues people had questions like that. We've developed answers to almost all of the questions now and as I just said, we will issue in our guidance identifying these --

MEMBER POWERS: Could you provide to us a list of questions?

MR. STUTZKE: Yes, let me see. More slides. The following sets of slides, these clarifications 2 through 4 are summaries of the issues, the questions and I realize they're a little bit tersely worded. That will all be in the interim guidance, the details. Now, for example, one of the questions was do we have to follow the format? And the answer is, well, the format is optional but the content needs to be there.

The reason why it's important is that COL. applicants in some cases are required by the regulation to follow the format of the generic DCD, they can't deviate from it. And so now, when we created our Appendix A to say here's what we wanted to see and it conflicted with what had been done in the past, they were concerned about it. Our answer is, we need the information but we don't care how it's presented.

Similarly, the risk evaluation --

MEMBER APOSTOLAKIS: Excuse me. Why would they go and raise that issue?

MR. STUTZKE: Well, the argument is if I look at my generic DCD, for example, for the ABWR, there are no numerical results in it, none. No report of what the CDF is, the contributors, important measures.

MEMBER APOSTOLAKIS: I don't understand --

the first bullet, right, format is optional but full content should be provided. They're worried about the format.

MS. MROWCA: This is --

MEMBER APOSTOLAKIS: Why is that important?

MEMBER CORRADINI: You've never dealt with the NRC.

MEMBER APOSTOLAKIS: I would love for the NRC to give me the format.

MS. MROWCA: What they're doing is they're using the phrase "incorporated by reference" to the DCD so it makes more work for them if they have to change their format in accordance with us rather than following their own DCD. So this is for those that have already submitted and certified.

MR. STUTZKE: Okay, another issue came up on seismic and fire risk evaluations. And staff has decided they can use the methods that were used in the design certification PRA, just an update of the information. Once standards are endorsed for these external events, we expect applicants to follow the standards. What we're talking about here is all of the design certifications so far are based on seismic margins. They're not seismic PRAs. We know --

MEMBER APOSTOLAKIS: And a lot of the fires.

MR. STUTZKE: Yeah, and the fire studies are like EPRI 5, fire and visible mobility evaluations. They're not true fire PRAs. So until such time as we get these standards out and we endorse them, you know, we will accept what's been done.

A question came up does the Appendix B quality assurance requirements apply to the PRA? And the staff has decided they don't. That doesn't mean there's no quality control at all. The quality control is provided by the standard itself. It talks about the need for peer reviews, maintenance of archival documentation, these sorts of elements.

PRA information is actually not part of the Tier 2 information. If you read the design certification rules it excludes the PRA, so therefore, it's not subject to the change process. Probably the more controversial one is what capability category is adequate for the PRA. Now, the ASME standard defines three capability categories, one being the lowest, three being the state of the art, okay. And the general notion is if you're Category 1, departures may impact the decision, may be a significant impact on your regulatory decision. Category 3 implies your PRA is very good quality like that.

When we look at the capability categories, you have to consider the category in terms of how it's being -- how the PRA is being used. Okay, that's fundamental. The quality needs to be commensurate with its application. And we considered the application so the PRA in just the design certification and the combined license demonstrating that you meet the Commission's metrics, like identification of vulnerabilities. And we generally believe the Category 1 is sufficient.

That being said, and knowing that you would ask, I actually did a little study that said, what do you get when you go from Category 1 to Category 2? What additional information or assurance do you get by this? In order to get capability Category 1, you have to meet 287 supporting requirements in the standard. Of those, about 210 are yes or no and you either meet the requirement or you don't. So they don't distinguish the capability category. My point is the capability category is distinguished by a sub-set, a rather small sub-set. In order to get from Category 1 to Category 2, you have to improve on 66 existing requirements and you have to do nine more. But consider the breakdown.

What do you think the most important thing is that you have to upgrade to get from Category 1 to Category 2?

Level 2, 24 requirements.

MEMBER APOSTOLAKIS: So Category 1 does not have an LRF?

MR. STUTZKE: No, it has LRF. I'm saying to get from Category 1 requirements to Category 2, you have to fix 24 supporting requirements for LRF. Only 12 for human reliability, only 11 for data. Those are the records.

MEMBER APOSTOLAKIS: These are the statistics, Marty. The question is, what are these requirements?

MR. STUTZKE: Well, I agree. The amount of effort it would take you to get from one to the other could be substantial. In other words, a single supporting requirement could be substantial.

MEMBER APOSTOLAKIS: The PRAs that we have seen for design certification, are they 1, Category 1?

MR. STUTZKE: My belief is they would fall mainly in Category 1.

MEMBER APOSTOLAKIS: Is it true that as a result of the requirement of frequent or periodic updates and upgrades, it may be five, 10 years the licensee will have a Category 2 PRA?

MR. STUTZKE: If he needed a Category 2 PRA to make a risk analysis to --

MEMBER APOSTOLAKIS: No, I'm asking whether it will happen de facto.

MR. STUTZKE: Why would it?

MEMBER APOSTOLAKIS: Well, how -- does Category 1 require uncertainty analysis?

MR. STUTZKE: Yes.

MEMBER APOSTOLAKIS: It does?

MR. STUTZKE: Yes, identification of all the key sources of uncertainties.

MEMBER STETKAR: Qualitative.

MR. STUTZKE: Qualitative.

MEMBER APOSTOLAKIS: So they will not have distributions for failure rates for example, will they? So how can you update your PRA if you don't have those? Qualitatively? That's what I'm saying that eventually you will end up with a Category 2.

MEMBER CORRADINI: What's eventually?

MEMBER APOSTOLAKIS: Nine years. If they have to update, I don't see how they can update it if they don't have quantitative measures.

MEMBER CORRADINI: But they're not going to have a plant -- I mean, unless I misunderstood the timing, it eventually is 2020 in 12 years, yeah, but not --

MEMBER STETKAR: Being a newcomer I have a little bit of latitude because I can claim ignorance. I think one of the concerns that I see about Category 1 versus Category 2 tends to be in the area of completeness, that's completeness and level of detail and let's not split hairs between those two for the moment.

I think it's relevant because in many cases in the real world, as people turn up the microscope and think more carefully about things and add more detail, and think more about completeness, they find things that they missed. And indeed, the core damage frequency and large release frequency increase. There's a bit of a problem that if you submit something in an early stage of the process that now has a number and we can't ignore the numbers, has a number associated with it through a relatively limited scope analysis following kind of the Category 1 guidelines, there then becomes a life to that number. And there is a lot of pressure that that number shall never increase. That's a bit of a concern by accepting a rather limited scope analysis that purports to quantify the core damage frequency and the larger early release frequency at an early stage of the process because there is a lot of -- both on the licensee's side, certainly on the licensee's side, a lot of pressure to show that the core damage frequency will never exceed that amount.

And therefore, as you add more detail to the risk assessment, as you turn up the microscope, there's a lot of pressure to screen out contributors that you didn't think about before but that could become important. So that's only a general comment and I guess I understand the reason to limit the scope at the early stage of the process because, in fact, you don't have as much detail to do a full Category 2 PRA. And in fact, if you never plan to use it for an risk informed regulatory requirements, there's no need to do a Category 2.

MEMBER APOSTOLAKIS: But could that problem of not changing the number, the pressure not to change the number, be present even if you did a level Category 2?

MEMBER STETKAR: Certainly. My only observation from experience is that if you try to meet the Category 2 criteria, there are -- there's an increased likelihood that you'll find some things that you would not necessarily think about if you just think about meeting the rather broad Category 1 criteria, either design or initiating events or subtle interactions between operations and design and so forth. I'm not talking so much about the fundamental plant design and the generic data that you use but --

MEMBER APOSTOLAKIS: I'm a bit surprised that you guys have agreed that Category 1 is okay.

MR. STUTZKE: Well, the other way to look at this is all of the licenses that we expect to be submitted now are going to be based on the design certification PRA. So we understand the level of detail that's been included in those and we're comfortable with it. Otherwise we wouldn't have granted the design certification. So we're looking at an update of work that's already been done, customization to make it plant specific. That's all. We're not looking for new expanded sets of initiators more detailed than selected.

MEMBER APOSTOLAKIS: Why not?

MR. STUTZKE: The rule doesn't require it.

MEMBER APOSTOLAKIS: Yeah, but if it's plant specific and there are some plant specific initiators then --

MR. ANDERSON: And we will trace the plant specific initiators, like service water.

MEMBER APOSTOLAKIS: Okay.

MR. STUTZKE: Okay, we have a number of comments from industry that this one-year prior to fuel load requirement of 57 norm age to meet standards wasn't enough time. And our response to it is, you know, that's the regulations. You need to position to change the rule or seek an exemption from the rule. We can't grant any latitude to that.

As George had said in his introductory remarks, industry has raised the issue of large release frequency and why we're using that for a Part 52 licensing. Why not use large main release. I will let Mark Ruben jump in but before I do that, I'll give you the basis for using large release frequency is the SRM to SECY 90-16, June 26th of 1990. And what is say is, "Consistent with the Commission's decision on SECY 89-102, the Commission approved an overall main release frequency of a large release of radioactive material to the environment from a RAM free accident is less than one in one million per year." That's the requirement.

It goes on to say, "The Commission has not agreed on a definition of large release and has requested a paper from the staff". The reality is we have not defined formally what's meant by large release.

MEMBER CORRADINI: From the reading material we've got though, I thought maybe they were referring to your second bullet about there's a working definition.

MR. STUTZKE: Well, there are working definitions. Large release was certainly defined in the design certification applications. Right, and if they're going to use the same PRA model with some modifications, customizations to make it plant specific, there's no reason to redefine those.

MEMBER CORRADINI: That was what in those answers.

MR. STUTZKE: Yeah, and we're comfortable with that.

MEMBER POWERS: It seems to me that a large release frequency is relatively easy to do.

MEMBER CORRADINI: I was just going to say, it's easier for me to understand that than the LERF.

MEMBER POWERS: Oh, very much easier.

MEMBER CORRADINI: Or am I off-base?

MEMBER POWERS: No, you're right on base. A large release frequency is that release which occurs less than one in a million times.

(Laughter)

MEMBER APOSTOLAKIS: I mean, in reading again 19.2, there is a Section 3 review procedures and it says you know, we are following Regulatory Guide 1.174 and the whole thing is on the basis of LERF.

MR. STUTZKE: All your figures are LERF.

MEMBER POWERS: George, it seems to me that the sooner we abandon LERF, the better off we're going to be because I can never understand what a LERF is.

MEMBER APOSTOLAKIS: That's a different issue. They're saying they want to --

(All speaking at once.)

MR. RUBEN: This is Mark Ruben. DR. Apostolakis, maybe I can provide a little perspective that goes back into the dim memories of a few of us who have been here that long. One thing I'd like to note is that 19.2 applies to licensing basis changes to plants licensed right now under Part 50. There is no baseline risk requirements or even guidelines for a Part 50 license plant nor is there any requirement for a PRA. That's not the case for a Part 52 license plant. The Commission has issued specific not change criteria to the licensing basis but baseline risk guidelines under their policy authority of core damage frequency, large release frequency and initial containment failure probability and I think the intent of the Commission is pretty clear that even though they're allowing an upper end CDF that by advance reactor standards might be viewed as a little bit high, they certainly wanted to control public risk and they wanted to enhance the containment isolation defense depth function and the life release frequency is not inconsistent with LERF per se, because they're used for two completely separate purposes, one is change assessment and the other baseline risk.

MEMBER APOSTOLAKIS: This document, this SRP there is no other SRP that has also Chapter 19. There is only one, right? SRP, Chapter 19 is only one. This applies to both existing reactors or will apply to both existing reactors and future reactors, correct?

MR. RUBEN: There hasn't been an opportunity to apply risk informed changes but I agree for a change, for a change to the limited license basis of the plant, 19.2 would apply but that doesn't change the baseline Commission-mandated life release frequency.

MEMBER APOSTOLAKIS: If I -- somebody builds an ABWR, okay? And in the year 2019, they want to come here and request a risk informed licensing base change. They have already worked with LRF, right, because that's what 2 says.

MR. RUBEN: That's correct.

MEMBER APOSTOLAKIS: Then they go to Chapter 19.2, that talks about changes and all of a sudden LERF is all over the place again. So they will come and argue then in terms of LERF, because the regulatory guide 1174 is I terms of LERF or there will be some other guidance in terms of LRF. That's what confused me.

MR. RUBEN: I think that is, yeah, an important observation, probably one that needs to be worked out in more detail in the future. I believe my understanding is that OGC considers the licensing criteria of these new reactors to be a permanent living requirement. So if they are going to make changes to the plant that would violate the baseline risk guides from the Commission, that would not be acceptable without an exemption or change to the license.

MR. HARRISON: This is Donnie Harrison from the staff. The practical rationale here is when you come into a permanent change request, the risk element that you're talking about in LERF is under Principle 4, the risk metrics. However, Principle 1 still has to be met which is your licensing basis. That's the -- and there you would still have the LRF, the CDF baseline numbers would all have to be still met. You'd still have to be consistent with your licensing basis.

MEMBER APOSTOLAKIS: So the LRF will have to be less than one in a million.

MR. HARRISON: Right.

MEMBER APOSTOLAKIS: If I want to make a change, that change does not allow me to go above one in a million.

MR. HARRISON: Right.

MEMBER APOSTOLAKIS: But the argument for getting the change would be based on LERF.

MR. HARRISON: Well, you're --

MEMBER APOSTOLAKIS: That's what it says.

MR. HARRISON: What would happen is you'd try to do a delta LERF calc but if your delta LERF calculation was greater than one in a million, you wouldn't be meeting the LRF baseline number. Therefore, you would fail on --

MEMBER APOSTOLAKIS: I'm already below one in a million. So that's not an issue.

MR. HARRISON: Okay.

MEMBER APOSTOLAKIS: And I want now to

make a change.

MR. HARRISON: Right.

MEMBER APOSTOLAKIS: This document sends me back to regulatory guide 1174 which is in terms of LERF and you agree with that.

MR. HARRISON: Well, in terms of -- no, it's in terms of LERF and LRF because LRF is now in your base which means in Principle 1 you have to maintain that base.

MEMBER APOSTOLAKIS: And I said I'd do that. But there is no requirement that tells me anything about delta LRF.

MR. HARRISON: Right, but there's a big difference because current Part 50 plants, they have to meet that subsidiary LRF.

MEMBER APOSTOLAKIS: I understand, I understand.

MR. HARRISON: Right, two things.

MEMBER APOSTOLAKIS: There is an absolute bound of LRF which if you're going to exceed, don't even count. Then you're below. Now, any changes that still satisfies that absolute bound will not be done in terms of LRF but in terms of LERF, because that's what this says, following 1.174.

MEMBER POWERS: And why is that not

reasonable?

MEMBER APOSTOLAKIS: I thought they wanted to get rid of LERF.

MEMBER POWERS: Well, I want to get rid of LERF but the staff want to live with it. They're saying why not do this?

(All speaking at once.)

MEMBER APOSTOLAKIS: It doesn't seem reasonable to me. I mean, you're switching to a new concept. Why doesn't one use that concept everywhere?

MEMBER POWERS: Yeah, what they're trying to be is more -- they're trying to be conservative in loss -- and early release is much more hazardous. I want to know how you're going to increase the early release, but you still can't go over one in a million.

MEMBER APOSTOLAKIS: For LERF -- LRF.

MEMBER POWERS: For any large release, you cannot go over one in a million but if you increase the early release from one times 10^{-7} to two times 10^{-7} they'll probably listen to you.

MEMBER APOSTOLAKIS: If that's the case, that's the case.

VICE CHAIR BONACA: I was wondering in the third bullet that you have sub-bullet on the definition of LRF addresses this issue.

MR. HAMZI: This is Hossein Hamzi. I think it's a very interesting discussion and I hate to end it because there are some good thoughts going on, but I would like to say that for the New Reactor Office, we know there is an issue with respect to differences between LRF and LERF and we're currently trying to put more time and study this further. And this is one of those areas that we call technical consistency between the operating reactors and the new reactors. So please, let's just not make any decision right now and let us come up -- do some more work and come out with some conclusion and once we decide what the position is, we'll definitely come back and share it with you and get your thoughts on this.

CHAIRMAN SHACK: Why don't you come up with a conclusion that LERF was an interim concept that should be killed as quickly as possible.

MR. HAMZI: All right, I will write it down. That's a good thought and we'll write it down and consider it.

MEMBER APOSTOLAKIS: Well, that's really, you know, part of my point, that if you want to switch to a new concept like LRF, then the licensing changes should also be based on that.

MR. HAMZI: And we understand that.

CHAIRMAN SHACK: Well, also the question is though, do you want to become more conservative than the QHOs.

MR. HAMZI: Why is that?

MEMBER APOSTOLAKIS: Oh, we're already more conservative than the QHOs.

MEMBER POWERS: Some of us don't believe that.

CHAIRMAN SHACK: There's an argument about that.

MEMBER APOSTOLAKIS: But there is something -- speaking of the QHOs, on page 6 it says, "Use of the Commission's Safety Goal Quantitative Health Objectives in lieu of LERF is acceptable in principle and licensees may propose their use." That's news to me. Is there a delta QHO that is acceptable?

MEMBER POWERS: Is there a QHO that's been calculated?

MEMBER APOSTOLAKIS: Well, that too. That too, but the licensing basis changes for nine, 10 years now, have been based on 1174, CDF and LERF. And all of a sudden you're throwing in this sentence that says, "If you, Mr. Licensee, want to do that, go to the QHOs".

MR. HAMZI: I know, I know.

MEMBER APOSTOLAKIS: Then you have powers all over you. You don't even know what the QHO -- no, you know the QHO. You cannot calculate the Level 3. I think you should delete that sentence.

MR. STUTZKE: To my knowledge, that sentence has always been there.

MEMBER APOSTOLAKIS: No, this has not been always there. Maybe in this document, but I think this --

MR. STUTZKE: It's in Reg Guide 1.174 and I don't know anybody that's ever availed themselves.

MEMBER APOSTOLAKIS: No, I don't think it's in 1.174, Marty.

MEMBER ARMIJO: I'd like to ask a naive question. The lack of specificity or the lack of formality in the definition of an LRF presumably pertains to the word "large". Is that correct?

CHAIRMAN SHACK: Frequency is well-defined.

MEMBER ARMIJO: Now, why is it difficult to define that?

MR. STUTZKE: Well, there's a definition of large early release in Reg Guide 1.17 --

MEMBER ARMIJO: No, I'm just looking at

LRF in and of itself.

MR. STUTZKE: Okay, the problem is -- the problem is large is not defined well.

MEMBER ARMIJO: Why couldn't that be defined in terms of things that are on the books, for example, dose limits in Part 20?

MR. STUTZKE: I think it's possible. I mean, there's several approaches. One can say large is large enough to create one expected fatality that's you're Level 3 space. Another approach is to say large is something that produces a dose of the site of more than X.

MEMBER CORRADINI: 10 CFR 100.

MR. STUTZKE: Something like that or large is some fraction of fission products, you know, pick your favorite one or a spectrum of one and find it physically.

MEMBER APOSTOLAKIS: The LERF is large unscrubbed releases. That's the words that are used in the definition of LERF.

MEMBER CORRADINI: What was used in the DC's that's what I wanted to ask somewhere in all this?

MR. STUTZKE: Anything that's not an intact containment sequence is a LERF.

MEMBER CORRADINI: But isn't that just a more sophisticated way of saying you've essentially violated 10 CFR 100?

MR. STUTZKE: Yes.

MEMBER APOSTOLAKIS: NRC has not issued a formal definition but is planning to?

MR. STUTZKE: I won't even say we're planning to now. We're considering ways and you can see a diversity of opinion among the staff now.

MR. RUBEN: Also, I think the Commission, when they specified not to define it at that point in time.

MR. DUBE: This is Don Dube. I've done a little research on the issue of large release frequency. There was actually a SECY issued by the staff that attempted to come up with a number of definitions of large release. In the end the SECY more or less says there was no definition of large release frequency, so the Commission never really approved a definition. But there is a SECY out there and I don't have the number off the top of my head.

MEMBER APOSTOLAKIS: How can you have guidance, numerical guidance of something you have not defined?

MR. DUBE: The staff has pretty much left it to the applicant to define it and then attempted to use several definitions. One of those definitions that they tended to use the most was Electric Power Research Institute Advanced Light Water Reactor requirements document which used 25 REM a half mile from the reactor. And that's what they tended to use and the staff has -- in its safety evaluations has looked at that and come up with some alternate definitions and in pretty much all cases --

MEMBER APOSTOLAKIS: That comes from Part 100.

MR. HAMZI: Yes.

MEMBER CORRADINI: It's the only thing historically that makes sense. I mean, you were worrying about this back in the '50s, so --

MEMBER POWERS: If you party to those debates, in the comment referred to, you will know that many people were very creative in coming up with alternative definitions of what a large release --

MEMBER CORRADINI: Make it bigger or smaller?

MEMBER POWERS: It has to do -- the speaker was correct. You can dial this just about any way you want to and find justifications.

MEMBER APOSTOLAKIS: Why can't we take the definition of LERF from 1.174 and take out the E?

MR. STUTZKE: We tried that and you end up with nothing.

MEMBER APOSTOLAKIS: Why?

MR. STUTZKE: The definition of LERF and 1.174 says either early containment failure or containment bypass. So it's defined in terms of early but not large.

MEMBER ARMIJO: But without a clear and formal definition of --

MEMBER APOSTOLAKIS: No, I think there is more to it.

MEMBER ARMIJO: But without a clear definition of what the word "large" means, does this mean anything?

MEMBER APOSTOLAKIS: There is no clear definition for core damage either in all honesty.

MR. STUTZKE: Yes, there is.

(All speaking at once.)

MR. RUBEN: These numbers are pretty conservative. Marty said some of the applicants use any containment failure sequence Level 2 at all. Others 25 REM it's not a huge dose.

CHAIRMAN SHACK: Yeah, I mean, that's the EPRI, it's the utility requirement document. So if you know -- if the vendor is out to meet the utility requirement document, he's going to meet that criterion. That criterion is conservative if you're looking at the QHOs. So I don't see why the NRC would be unhappy with it. The question is, should you require them to meet that. So, you know, it's an acceptable number. What is the required number I think is where the -- the staff can find acceptable numbers, but I think the staff has a hard time coming up with a required -- you know, what should you require the LRF to be? But let me come to a different question here that pertains to another problem I'm facing at the moment.

When you guys accept this LRF for the design certification, is that with safety systems only? You know, is it like the 10^{-4} where you know, you've got a constrained PRA or is this everything is working and I'm going to meet the LRF of 10^{-6}?

MR. STUTZKE: That's attempting to credit every system you've got.

MR. RUBEN: This is not what they used to call focus period when AP 600 was trying to determine what to do with the diesels.

MEMBER APOSTOLAKIS: So this idea of a focus PRA doesn't exist any more?

CHAIRMAN SHACK: No, it does for the 10^{-4}, doesn't it?

MEMBER APOSTOLAKIS: I thought it was for both.

MS. WIGGINS: Well, that's what I'm trying to clarify.

MR. RUBEN: No, the focus PRA was specifically to help delineate safety grade from non-safety related components but these metrics that we're talking about, baseline risk criteria, is base PRA practices, best estimates as far as you can do it.

CHAIRMAN SHACK: 10^{-4} for the new plants is everything?

MEMBER APOSTOLAKIS: No, no, because the design we're reviewing now, I remember specifically that the focus PRA results are compared to the goals, not the whole thing.

CHAIRMAN SHACK: That was certainly my understanding but you know, I'm willing to take a correction from the staff who is actually doing the reviews. So that's everything is 10^{-4}.

MEMBER APOSTOLAKIS: No, that's not true.

MR. RUBEN: Yes. There may have been a comparison against 10^{-4} to make that determination of safety related versus non-safety related. But in terms of meeting the Commission's mandated baseline risk guidance --

MEMBER APOSTOLAKIS: It should be everything.

MR. RUBEN: -- it's everything.

CHAIRMAN SHACK: You know, there's the discussion of you should create the regulations to make sure that the QHOs are met and therefore, you have -- you know, you have regulatory requirements on the safety-related systems. The other systems you have less control over. So you know, I thought there was a clear distinction that you had to meet that with your safety related systems.

MEMBER APOSTOLAKIS: Exactly, that was my impression, too. Now, let's --

VICE CHAIR BONACA: To take a neutral framework.

MEMBER APOSTOLAKIS: We can find it. I remember it was on the left page.

VICE CHAIR BONACA: That's the main issue.

MR. STUTZKE: Right.

MEMBER APOSTOLAKIS: We are running a little bit late and there is one more thing I want to raise. You have a beautiful discussion on page 7 of how one may combine several individual licensing basis changes. And this is very consistent with Regulatory Guide 1.174. But some of the changes may lead to decreasing risk and the total is acceptable and so on. Nowhere in here does it say that you should keep track of all the changes that were done since Pericles was running Athens like 50.46 wanted to do and everybody got so excited by it. Do you see the difference? To do the licensing -- the changes now, you want to consider three of them, fine, all three.

If they are approved, and you have another request six months later, that should be independent of what you did today. And I hope everybody understands that because in 50.46 there was a fundamental change. They said you should kick back of all the changes from day 1.

CHAIRMAN SHACK: That means you're allowed to creep up to 10^{-4} even if you start at 10^{-6}.

MEMBER APOSTOLAKIS: It seems to me that either we have 1.174 and we comply with it, or we don't and if we want to change it, we should change 1.174, not try to sneak into new regulations, new things.

MEMBER POWERS: George, you presume that 1.174 and I'm sure you think this in your mind, but it is not a God-given thing that is codified in the regulations.

MEMBER APOSTOLAKIS: It is God-given. It took us two years to do. You were there. The staff tried very hard and there is a general principle that if you have guidance and regulations, you try to follow them. You don't change them on the way without some formal process.

MEMBER POWERS: But it's not part of the regulations.

MEMBER APOSTOLAKIS: It's a regulatory guide that --

MEMBER POWERS: As the staff has told you over and over again, it's used for existing reactors.

MEMBER APOSTOLAKIS: It's one of the topics.

MR. RUBEN: On a voluntary basis.

MEMBER APOSTOLAKIS: It came down from the mountain.

MR. RUBEN: On a voluntary basis, I would add, which is not the case for a Part 52 smaller licensed plant.

MEMBER APOSTOLAKIS: Okay, okay, I just wanted to remind the Committee of that. It was not addressed to you. Can you finish in 12 seconds?

CHAIRMAN SHACK: Fast forward, all right.

MR. STUTZKE: The other clarifications are mainly, you know, I'll call them administrative or editorial, like that. So we will issue interim staff guidance probably within a month or so. I'm still developing it. The other thing I wanted to point out to the Committee is NRO is working hard now in advance of getting actual COLs. They're collecting risk insights from all the design cert PRAs and putting them in a usable form for reviewers.

Staff is doing what are called QA reviews. The DRP and USA PWR and PRA folks are involved in that. We've done some work on preparing to do our acceptance reviews and preparing for PRA audits. So we fully expect to hit the ground running once the first complete COL is submitted. We believe we have a good approach that will get us where we need to be.

MEMBER APOSTOLAKIS: Thank you, Marty. Any questions from the members?

MEMBER ARMIJO: I'd just, again, reiterate that without a clear specific definition of the word "large" in LRF, this is all really meaningless because you can't specify probability for something which you have not defined.

MEMBER APOSTOLAKIS: You know they will introduce fuzzy sets.

MEMBER POWERS: It's just not clear to me that that's true at all. It seems to me it's entirely possible to define -- to leave large in the eyes of the beholder. Very clearly, you know that a 25-REM at the site boundary is considered a significant release, and so anything big relative to that would absolutely be large.

MEMBER APOSTOLAKIS: Yeah, but Said's point don't say that. So say it, if that's the case, say it.

MEMBER ARMIJO: That's fine, nail it down and get on with it.

MEMBER POWERS: If we define core damage as something larger than the one percent of fuel damage that we allow plants to operate at and we don't have much more of a definition than that. Fortunately, the physics of the situation, which I suspect is also true in reactor accidents, is such that if you get a little bit over one percent you get into a world of trouble and in a hurry and I think the same thing will happen to you simply because the normal gases are so hard to keep inside the plant once they decide to wander away from the interior of the clad.

MEMBER APOSTOLAKIS: I think the way the

accident sequences are modeled, there isn't a continuum. In other words, if the definition is five percent of the noble gases, the next more serious sequence will really release a lot. So you never have a question is it five or six or three or four. So that helps a little bit with the fuzziness. But in principle, you're right. I mean, you got to have a definition.

MEMBER CORRADINI: Just for our own historical, Marty suggested this one SECY, I wrote it down, but I think if we could get that -- maybe the newer folks, get that, also get what Don was suggesting about in terms of a SECY document that was kind of discussing the range and the supporting NUREG. That would help us get some background because I have this vague memory of all of this relative to the analysis. It would help for our background.

MEMBER APOSTOLAKIS: Well, this afternoon, we will discuss whether we want to write a letter and then these issues will come up again. So I propose we recess for lunch and defer this discussion for the afternoon. Okay, Said?

MEMBER ABDEL-KHALIK: Yeah, sure, absolutely.

MEMBER APOSTOLAKIS: Thank you very much, Marty. As entertaining as usual. Mr. Chairman, back to you.

CHAIRMAN SHACK: All right, if we can be back at 1:30 for our next presentation. We're off for lunch.

(Whereupon at 12:25 p.m. a luncheon recess was taken.)

CHAIRMAN SHACK: I think we can come back into session if I can find my agenda. Our next topic is Proposed Recommendations for Resolving Generic Safety Issue GSI-156.6.1 Pipe Breaks Effects on Systems and Components Inside Containment and I'm the subcommittee chairman for this. I notice that Harold has a fairly good description of the history of the problem here. I was going to do that, but I'll just let him give him his presentation since he has it.

MR. VANDERMOLEN: Does management want to say anything at this point? Okay. Thank you, gentlemen. Yes, this is Generic Issue 156.6.1. My name is Harold VanderMolen. I'm with the Generic Issues Group. On my right here, is Mr. Abdul Sheikh who is in our mechanical and structural engineering branch who has done some of the calculations.

If we go on to the next slide.

(Off the record comments.)

MR. VANDERMOLEN: We're going to talk a little bit for the first three bullets which are really background and context material. This issue is in its, what we call, technical assessment stage. So we'll talk a little bit about this historical background, the nature of the question and the screening analysis which put it into the technical assessment stage. But the material we'd really like to cover, the new material, is the BWR investigation and the PWR investigation, two separate things that attack similar questions but take different approaches.

Now let's talk a little bit about the history of issue because you really can't understand it without a little bit of background. This issue goes back a long way. What's the basic question? It's simple enough, one that you're all familiar with. Obviously, if you have a pipe break within containment. We have all kinds of engineered safety features that are designed to deal with the inventory lost, be it primary or secondary.

But one of the requirements we've had all along was that the break itself should not disable any system that you needed to deal with it. This goes all the way back to 1967 when they put in the general design criteria. The GDC, particularly GDC-4, requires that any safety system be appropriately protected against dynamic effects and it explicitly includes missiles, pipe lifting and discharging fuels. Every plant has been built in accordance with this general design criterion.

Now we have a lot more specific about how you do this when the standard review plan was issued and now I gather from all of the material that I've seen around this room that I do not need to discuss the standard review plan. I gather you've had quite a discussion about it earlier today.

But the question here is that the standard review plan was first issued in 1975. It's had some other versions since then obviously, but first issued in 1975. The natural question was what about these plants that were built and licensed and designed obviously before 1975. Do we need to go back and look at these older plants?

That was really the essence of this issue and it turns out that if you look at the actual history there are 51 plants that were designed and licensed before the SRP was put in place. That's a lot of plants. Of those 51, 10 have since shut down for one reason or another. But that still leaves 41 operating. That's 18 boiling water reactors, 23 PWRS. So it's still a significant number of plants.

Again, looking at it, you need a little bit of context for this history. The question did not start with this generic issue. The SRP was issued in 1975 and as early as 1977, the staff started something called the Systematic Evaluation Program which I think some of you would be familiar with. The SEP as we call it was in several phases and it not only looked at this issue with pipe breaks but a lot of issues about these older plants and what was appropriate to grandfather and what was not.

There were, in fact, 137 safety questions involved with that Systematic Evaluation Program.

MEMBER WALLIS: So you're telling me that someone raised a question 30 years ago.

MR. VANDERMOLEN: That's correct.

MEMBER WALLIS: And you're still trying to answer it today.

MR. VANDERMOLEN: Yes. I'm going to describe how, too.

MEMBER APOSTOLAKIS: I want to raise an issue now that won't be resolve 30 years from now. I'm trying hard to figure out, but --

MR. VANDERMOLEN: We'll be glad to put it on the list. What happened was the SEP went into a Phase II and actually looked at ten of the oldest plants to see what criteria needed to bel looked at and based on their review, it was a fairly extensive one, with interactions with these licensees, they reduced the issues from 137 to 27 where they were able to resolve 110 of these safety questions.

MEMBER WALLIS: Should we be relicensing these plants?

MR. VANDERMOLEN: Well, they cannot be relicensed without looking at these things. Actually, it's built into our regulations.

MEMBER WALLIS: We don't look at this when we do license renewal, do we?

MR. VANDERMOLEN: There is a provision in the regulations that any plant up for renewal must look at all active issues and all issues that apply to them before they can be renewed. Yes.

And there was another program called the Integrated Safety Assessment Program or ISAP that came in in 1984 that answered a similar question but used what was then the new probabilistic approach as well. So it managed to reduce the issues down from 27 down to 22. Now do understand that in that time period also of 1979 we had an event that dramatically changed how we did things here in the Agency. So things were pretty busy around here. I lived through that period. I can testify to it.

So things were pretty active. Things were being looked at but, finally, in 1990, the SEP Program was terminated and instead the remaining issues, 22 of them, which were the ones that were thought to be the least important of the original ones were transferred to the Generic Issues Program. They became Generic Issue 156. That's why you see that rather strange nomenclature, 22 issues. They ran from 156.1.1. to 156.1.2 all the way up to 156.6.1. Of those 22 issues, 21 have been resolved for some time. This is the only one left of that whole list. So it's been a long road.

In 1994, 156.6.1 was given a medium priority, but it's just the nature of this issue that's not amenable to a probabilistic approach. So they don't have --

MEMBER WALLIS: What happens to the low priority item?

MR. VANDERMOLEN: We don't work on it. We just keep it on the books.

MEMBER WALLIS: It never gets done. Is that right?

MR. VANDERMOLEN: Yes. Exactly so.

To expand, Mr. Wallis, a little bit more to your question which is a valid one, by policy that was enacted which was approved by both this Committee and the by the Commission back in the early '80s, we did these things not in order that they came in but in the order of perceived risk importance. That's why we do an analysis at the beginning. That was the original scheme.

Some years later when the safety goal came out, we suddenly had an absolute measure to put them against and then with some appropriate margins to ensure that we did the right thing, we were allowed to essentially drop them forever. So this was a conscious decision and it is well supported in our procedures and in documented Commission policy. This is also why when you do them in order of perceived risk importance inevitably the ones that last a long time are the ones that tend to be of low importance. So this does not surprise me. I would feel very badly if we had an important issue that dragged on for a long time.

This one kept on going primarily because there were large uncertainties in our original estimates and the Agency contracted with the Idaho

National Engineering Laboratory which has gone through several different names since then to do what we called at the time an enhanced screening assessment. We basically asked them to do a more systematic look at this issue and assess should we be doing this or not and do we really need to do anything and these two columns seem a bit backwards. The one on the left says how they did it and the one on the right says what they did.

If you'll direct your attention to the column on the left for a moment, the Idaho people looked at the SFARs. They reviewed the reports of that integrated plant safety assessment program we just described which I thought was a rather clever idea, also looked at what design changes were made in containments after the SRP was put in place to see where changes were necessary.

And finally, based on this information they performed five actual plant or site visits trying to get as close to things as they could and they did things in a rather systematic fashion. And something you often do when you're doing probabilistic analysis, you aim high and then sharpen your pencil. We started out with a big level, big first level, list of concerns, basically a checklist for every system in the containment. Using their information, they narrowed the list down. They got it down to about 16, not about, 16 BWR items and 17 pressurized water reactor items.

And then they did a sort of a probabilistic screening. I do not mean a full PRA with fault trees. I just mean, you can read this in the analysis of record, a series of probabilities trying to fine it down. This is all it is. This is not intended to be the state-of-the-art analysis. It was intended to get this thing down to a manageable problem.

This assessment is the basis of our screening analysis of record which you can read in NUREG-0933. And the results of the analysis for boiling water reactors, not surprisingly, they found that the Mark I containments tended to be quite similar, not identical but similar. The BWR containments almost by their nature, particularly the fact for the product line three and beyond where you have two recirc pumps and two semicircular headers, the reactor naturally splits into two parts. So it really encourages you to put things in on opposite sides of the reactor. There's not much room in there. So when you start talking about dynamic pipe effects, for almost anything that can happen, the reactor or the primary biological shield which is this concrete cylinder that's just outside the reactor is in the way.

I would have thought just at a first glance when I first read this they're probably not going to find anything. Well, they did. They found some sequences that involved drywell puncture which we're going to describe in more detail in just a moment that they decided should be looked at. That's the BWRs.

For pressurized water reactors, those containments varied much more. Not surprisingly, you have any number of architect engineers and you have three major PWR vendors. You could make a few general statements looking at the Idaho analysis and just the knowledge we had. The PWRs, it's not so much the primary piping that is the problem here. The real reason is that you put in steam generators each in its own vault and it's quite difficult for a breaking pipe to disable a system that's in some other LOOP. So you have a fair amount of redundancy and a fair amount of natural protection.

However, the system, the things look very different if you look at the secondary piping. Most of these containments, not all, but most of them inside the containment wall, as most of you probably know, there's another wall. It doesn't go all the way to the ceiling but if you work at the plant, it's usually called the crane wall because it supports the cooler crane. If you look at the licensing documents here, it's called the missile shield because that's it's other function. But anything in that annular region may or may not be compartmentalized. Some of them are, but there you may have steam lines running adjacent to other things that you may want to have and that's what we concentrated our efforts on. This is where we stood before and this is where we start for a technical assessment.

Now I'm going to look at each one of these things in turn. First, the BWR analysis, the scenario for a boiling water reactor is that a whipping pipe punctures the drywell wall, discharges steam into a gap that's between the drywell wall and the concrete secondary shield wall and that steam will be forced out into an area around the ECCS equipment. It's easier to see that by far with a picture which I hope is going to be visible. Many of you, I know, are already familiar with this. Please bear with me. Not everybody is.

If you look at a BWR primary containment, the area down here by the base mat, the steel shell is in contact with the concrete. However, if you get up in this area, the upper portions of the containment along the side, there is a two to three inch gap between the freestanding steel containment and the concrete secondary shield wall to accommodate thermal expansion. That's there on purpose and if you were to break a pipe in here and it whipped and punctured that primary containment wall and discharged steam into that gap, the gap area is closed up at the top here at the refueling bulkhead. It has to be because you flood this up with water when you refuel a reactor and the steam would come down.

The only place it has to escape, the primary place anyway, is along these vents and into this large square room that houses the pressure-to-pressure chamber, the big torus. The four corners of that room generally contain the ECCS equipment. So if this scenario really does happen, you will possibly by the hostile environment disable your ECCS. If you do get in trouble in the core, you have already punctured your primary containment. Now this the Idaho Laboratory recommended that we take a better look at and we certainly agreed that this really should be looked at.

So the question is this is not, you can put probability numbers on this, of course, certain that any of this will happen. But we thought we'd look first at whether we could really puncture this at all. So for this, we did or Mr. Sheikh here did some calculations to actually look at the credibility of this and I'm going to let him pick up at this point and describe some of his calculations.

MR. SHIEKH: Okay. So what I looked at is the three major piping which are in the BWR, the main steam pipe, the feedwater pipe and the RCS pump discharge lines at the nozzles. I did the deterministic approach. I used the ANSYS computer code. I considered the lower and upper bound values of the flow-down forces for different pipes. I used the minimum thickness of the drywell for this analysis and I considered a gap which was three and one-eighth of inch instead of a normal as-built gap of two inches which means the upper bound values and the conservative route range.

I also, the next sheet, if you see just pinpointed these lines, the steam line, the feedwater line and the RCS pump discharge lines inside the containment. So the analysis results are the main steam line is a 24 inch line. It has a thickness of 1.3 inches. It has a minimum ultimate strain of 22 percent. The nearest, the gap between the drywell and the steam line, is about 16 inches and the pipe has an operating pressure of 1,050 PSI.

We assumed the double-ended guillotine break at the nozzle and used the pi by force equal to 0.7 to 1.2 times the pressure and the area of the pipe. That's a lot of force and did the analysis and found that a strain in the drywell, the pipe hits the drywell, pushes locally the drywell in contact with the concrete and it has a strain of about ten percent as compared to the minimum specified strain in the drywell of all type of steel is about 17 percent. So our conclusion is drywell will deflect and come in contact with concrete but the drywell will not perforate because the strain level hasn't reached that level and the drywell integrity will not be compromised.

The next picture is the show-and-tell of the ANSYS's model which shows the pipe, half-size pipe, and the drywell and the concrete behind it.

The next picture shows what happens to the pipe and the drywell after impact and as you can see those two arrows in the middle, that's where the pipe is in contact with the drywell and the drywell is in contact with the concrete and these are the points where they are the maximum strain in the drywell of ten percent. And there is the large strain in the pipe, but we don't really care what happens to pipe at that stage.

The next page 15 shows the variation of the strain in the drywell depending on the force and you can see the pipe has deformed substantially more than the drywell and the maximum strain is ten percent and that is at the peak upper bound value of the main force in the pipe which is the double guillotine break 1.2 times the pressure times the area of the pipe hitting the drywell.

MEMBER WALLIS: What happened to the other piece of pipe, the other double-ended break?

MR. SHIEKH: That is at the nozzle.

MEMBER WALLIS: That's the vessel.

MEMBER MAYNARD: Right at the very top, I think.

MEMBER WALLIS: I thought there was another piece of pipe left sticking out of the vessel.

MEMBER CORRADINI: That gives you the biggest whack.

MEMBER WALLIS: The biggest whack.

MEMBER MAYNARD: It hinges off of that thing.

MEMBER WALLIS: It does?

MEMBER CORRADINI: Yes. Because it's tangling like that. So it goes back.

MEMBER MAYNARD: Yes.

MEMBER WALLIS: But it could break away.

MEMBER MAYNARD: You broke it at the top of the vessel. Right?

MR. SHIEKH: Right. If you go to page 11, you see the steam line and you see where it's connected to the vessel. That's where we break it and that is traditionally where we assume, always assume, a pipe break.

CHAIRMAN SHACK: I mean you don't want to waste any of your force bending the pipe. So you give it the longest moment arm. So you get the most deflection and you get it to the wall wasting the least amount of force.

MEMBER WALLIS: So this analysis takes proper account of plastic defamation, does it?

MR. SHIEKH: Correct.

CHAIRMAN SHACK: It takes account of it, yes.

MR. SHIEKH: Yes.

CHAIRMAN SHACK: It's supposed to take account of it.

MEMBER ARMIJO: Is the defamation wherever this thing is hinged or pivoted? Is that all plastic way down there?

MR. SHIEKH: No. It is plastic. It has reached a strain of ten percent. The use strain is only 0.2 percent.

MEMBER ARMIJO: Does this take into account the momentum of the steam that's leaving that's leaving at the speed of sound?

CHAIRMAN SHACK: Better.

MR. SHIEKH: It's better because it's 1,050 PSI.

MEMBER CORRADINI: You have three measurements in your paper or in the paper in the analysis that you had a Moody analysis. I can't remember, various. Is that what those three analyses led you to the 0.7 to 1.2?

MR. SHIEKH: Right.

MEMBER CORRADINI: Those -- All those computations were on the lower end of that.

MR. SHIEKH: No, these are the three -- If you go to --

MEMBER CORRADINI: That's okay. But it's

those three analyses that gave you the range of your force factor. Right?

MR. SHIEKH: Right. That's correct. And that is acceptable for all the new reactors. That's what they have used in their analysis when we designed the piping restraints. This all assumes that there's no piping restraints on these lines.

So then we go to page 16. Then we looked at the feedwater line break. This pipe is a very smaller diameter, ten inch diameter. It has a wall thickness and the pressure is the same. Now the piping force is more in this case because it's water and not steam. So we considered as Moody's and Bechtel approach. We considered the pressure to be much more, I mean, the total force to be much more. It's between 1.3 to 2.1 PA.

What happens in this case, the analysis shows -- I don't have all the pictures, but the analysis shows that the pipe deflects to 18 inches and there will be a plastic hinge formed. However, the nearest drywell is about 24 inches away. That means the pipe will break before it hits the drywell and, obviously, even if it breaks and then hits the drywell, the impact force is going to be much less than the steam line force which is about three to four times the force of the feedwater line because of the size of the pipe.

MEMBER WALLIS: Where it's steam line, should it be water line there?

MR. SHIEKH: I'm sorry.

MEMBER CORRADINI: It should say water I think he's saying rather than steam. It's feedwater.

MEMBER WALLIS: A water line, not a steam line.

MR. SHIEKH: I'm sorry.

MR. VANDERMOLEN: He means --

MEMBER WALLIS: I think you just carried it over from the other slide.

MR. VANDERMOLEN: Where it says "steam line" up there. That should be water.

MR. SHIEKH: Yes.

MR. VANDERMOLEN: That should be feedwater, yes.

MR. SHIEKH: I didn't proofread it properly.

MEMBER WALLIS: And you used the Moody method or something for the flashing flow of the water.

MR. SHIEKH: Correct. There are three approaches and I have outlined this in the paper which are acceptable and we used the two to make --

MEMBER WALLIS: But you could use conservative, the maximum, whatever gave you the maximum.

MR. SHIEKH: Correct.

MEMBER WALLIS: Presumably momentum matters here, does it?

(Off the record comments.)

MEMBER WALLIS: Presumably momentum matters, does it?

MR. SHIEKH: I don't remember.

MEMBER WALLIS: It doesn't matter here?

MR. VANDERMOLEN: It does.

CHAIRMAN SHACK: I mean, the static pressure really acts as a momentum.

MEMBER WALLIS: It's the static pressure that really pushes the pipe.

MR. SHIEKH: Correct.

MEMBER WALLIS: Okay.

CHAIRMAN SHACK: Well, it creates momentum in the flow going that way. So the pipe is --

MEMBER WALLIS: But what you really use is just the pressure acting on the pipe that pushes it.

CHAIRMAN SHACK: Right.

MR. SHIEKH: Correct. It's the force, but it's transferred into a force and we apply it all along the circumference of the pipe.

And since the pipe in this case failed at the highest force and it still would not hit the drywell and suppose it fails and then hits the drywell, the momentum, most of the force will be lost in making the plastic hinge and breaking the pipe. So there won't be much energy left if it hits --

MEMBER WALLIS: These are pipes which are freestanding and then they hit the drywell.

MR. SHIEKH: Right.

MEMBER WALLIS: Presumably, there are pipes that go through the drywell.

MR. SHIEKH: Yes, but they are not -- That's not where the break occurs.

MEMBER WALLIS: But it could be.

MR. SHIEKH: The critical stress points in the piping systems are at the nozzles and the stress is for a guillotine -- The stresses in the pipe along a straight run of the pipe are much less because when you do the piping analysis you increase the stresses at the nozzle or at the elbows by a factor of two to three times. I don't have it handy but that's how we calculate the breaks in the pipe and if you see the standard review plan, and there may be paper on it, it tells you that you have to assume a break at the terminal ends and also anywhere where the stresses exceed certain margins. So far as for I know all the years I worked, you never have a break in the middle of a line. Usually the breaks are at the valves.

MEMBER WALLIS: If you have a big flaw there.

MR. SHIEKH: I'm sorry.

MEMBER MAYNARD: A manufacturing flaw or --

MEMBER WALLIS: You might have a flaw which has been growing there in the middle of the line.

MR. SHIEKH: That is true, but this is --

CHAIRMAN SHACK: Typically, though you're going to have flaws at welds and welds are going to be at nozzles or elbows.

MEMBER WALLIS: Yes. I know. But you could.

MEMBER MAYNARD: You could.

CHAIRMAN SHACK: If you're just postulating, yes. Sure.

MR. SHIEKH: But that will be taken care of. Anyway, I considered what is this kind of practice for the design of the plants which were done after SEP.

Going back, the conclusion is drywell will stay and it will not be --

MEMBER WALLIS: Now wait a minute. You're just looking at mechanical damage to this drywell.

MR. SHIEKH: Right.

MR. VANDERMOLEN: Yes.

MEMBER WALLIS: Because when we've had pipe breaks in containment as I remember there were cases where the hot jet impinging on the shell actually does considerable warping of the shell.

MR. SHIEKH: Correct.

MEMBER WALLIS: And so presumably, once this thing has been dented, it's then subject to some sort of thermal harassment.

MR. SHIEKH: Right, but the pipe has already hit the drywell.

MEMBER WALLIS: It's already hit, but then the steam hits it afterwards.

MR. SHIEKH: Correct, but now the drywell is backed by the concrete. So it has nowhere to go.

MEMBER ARMIJO: It might buckle locally if it got hot.

MR. SHIEKH: Correct.

MEMBER WALLIS: Or it could do various

things, yes.

MEMBER ARMIJO: But there are restraints on these big, long pipes, aren't there?

MR. SHIEKH: There are. This is what I'm saying. What we have considered is there are not restraints.

MEMBER ARMIJO: Okay.

MEMBER WALLIS: Ah, worst case.

MR. SHIEKH: Worst case scenario.

MEMBER ARMIJO: And you picked them at the nozzles where the force is at right angles to the wall of the containment.

MR. SHIEKH: Right.

MEMBER ARMIJO: So that's conservative, very conservative. That's good news.

MR. SHIEKH: Okay. And then on page 17, we looked at the RCS pipe. This is a stainless steel pipe. It's a 28 inch diameter maximum. The wall thickness is one and a half inch. Since it's stainless steel pipe, it has a higher ultimate strength. But the thing which helped us is the pipe is located further away from the drywell because it's in the bulb at the bottom of the containment and we found looking at different plants that it's about 168 or in that range from the -- There's a gap between the drywell and the steam line which is about 168 inches.

We again looked at different ranges of the pipe, of course. We found that a deflection, a maximum deflection, which is unimaginable but at the 40 percent strain level is about 148 inches which if you see the picture on the next page, it looks weird. But that's how it comes out if you let it deflect and don't fail.

And if you see on the top, the drywell is still 76 inches away from the deflected shape. In this analysis, we didn't consider the other resistance which will be provided by the platforms deal which comes in the way and there are sometimes smaller pipes which are in the way. So those pipes will resist part of this force which hasn't been considered.

MEMBER WALLIS: When does it stop moving? What stops its deflection? What limits the deflection?

MR. SHIEKH: Because the pipe has reached the force. It has moved up to there, right, and --

MEMBER WALLIS: Now the force on it is in a suitable direction.

MR. SHIEKH: Right.

MEMBER WALLIS: It doesn't yield anymore.

MR. SHIEKH: Right. If you see now the

force is --

MEMBER WALLIS: But there's presumably a force on it.

MR. SHIEKH: Yes.

MEMBER WALLIS: But it's in a direction that doesn't produce any further yield.

MR. SHIEKH: Right.

MEMBER WALLIS: And it doesn't buckle as it deflects.

MR. SHIEKH: That's what I said. This thing, consider, it didn't buckle. But if it buckles, that's to our advantage.

MEMBER WALLIS: Then it would presumably break more if it buckled.

MR. SHIEKH: Yes. It breaks and then the energy, most of the energy, will be lost in breaking the pipe. So even after that, if it impacts the pipe drywell, the force will be very small.

MEMBER WALLIS: No, it keeps coming, doesn't it?

MR. SHIEKH: No, it's only --

MEMBER WALLIS: You've already blown down.

MR. SHIEKH: Right.

MEMBER WALLIS: The blowdown is so quick the energy doesn't keep coming.

MR. SHIEKH: Right. That's -- There is that --

MR. VANDERMOLEN: It blows down over a period of time, but it's dropping. The pressure behind it is dropping during this period, too.

MEMBER WALLIS: So it's a race between the deflection of the metal and the decrease in the pressure.

MEMBER CORRADINI: But if you had a break somewhere else you would be losing fluid there. So your total force is going to be dropping.

MEMBER WALLIS: It is dropping. The question is how fast does it drop compared with how fast is the pipe moving.

MR. SHIEKH: If I remember --

MEMBER WALLIS: If it would move quicker, then the pressure would go down.

MR. SHIEKH: If I remember it's in terms of milliseconds.

MEMBER WALLIS: Yes, it's milliseconds.

MEMBER ARMIJO: For the deflections, but the blowdown would take longer.

MEMBER WALLIS: Much longer. The blowdown takes much -- The energy keeps coming.

MEMBER ARMIJO: Right. But if it buckled, it's going to flatten.

MEMBER WALLIS: It's going to fold.

MEMBER ARMIJO: And it's going to fold. It's going to reduce your --

MEMBER WALLIS: You're going to swing around the buckle presumably.

MEMBER ARMIJO: Buckling is okay.

MEMBER WALLIS: Yes.

MR. SHIEKH: Buckling is all right.

MEMBER WALLIS: I would think it would buckle and make a hinge and then you would have this thing flopping all the way around.

MR. SHIEKH: That's the main concept.

MEMBER WALLIS: It would stop the flow or restricts the flow.

MR. SHIEKH: That's the reason we put the pipe through restraints at the elbows so not to allow it to form the plastic. In this case, we haven't considered whether they are there are not.

MEMBER CORRADINI: So I guess this is time to ask that question and I don't want to make a problem where there's not a problem. But I just want to understand. So you did what I consider to be a bounding analysis without pipe whip or pipe restraints and if I understood correctly also, looking for the worst location for the break. Right?

MR. SHIEKH: Correct.

MEMBER CORRADINI: So when you put in the reality of the pipe restraints that was part of the Idaho, the INL, analysis and they've determined that once the restraints were in you never made it worse. You never actually -- In other words, it appears that you now have the bound, but once I start putting in reality I don't create something that is kind of not as bad at least at the bounding case, but I create another issue somewhere else. Do you see my question?

MR. SHIEKH: No, I didn't consider piping restraint.

MEMBER CORRADINI: They just simply looked at the bounding analysis.

MR. SHIEKH: Right.

MEMBER CORRADINI: And effects directly on drywell.

MR. SHIEKH: Yes, and they assumed as soon as there is a break, they assumed a probability of 0.5 or even sometime a probability of -- and that's how they reached the probability level to make it an important issue. They didn't do any analysis. Their work was more focused on probability.

MEMBER CORRADINI: Okay. Thank you.

MEMBER WALLIS: But just to back up a bit, when they do these containment analyses they put in nodes and all that. I'm not aware that they look at the effect of the jet on the containment itself. There's a jet aimed at containment. You're heating this region up to 600 degrees or something.

MEMBER APOSTOLAKIS: Where at?

MEMBER WALLIS: Which produces a lot of buckling at that region and the drywell presumably.

MR. SHIEKH: Whereas I know with -- Are we talking of BWRs or PWRs?

MEMBER WALLIS: I don't care. I mean, if you get a jet of water and steam aimed at a steel wall, it heats up the region of impact and that does buckle. There have been instances of significant buckling of containments. A water hammer has broken a pipe for instance. I just don't know if this is taken into consideration when they look at the integrity of containment because they always seem to have these gothic codes and things which have a couple of nodes and everything is homogenous which it isn't.

MR. SHIEKH: When we designed the containment which is --

MEMBER WALLIS: Did you look at the local impact of the hot water jet on the wall?

MR. SHIEKH: Not in that sense of the -- I have to go back and check it. But I --

CHAIRMAN SHACK: I think in reality this thing is going to be way -- You're going to get a pretty good mixing action.

MEMBER ARMIJO: You get a lot of -- the nozzle.

MEMBER WALLIS: It depends how close it to the wall, yes.

MEMBER CORRADINI: If it's a drywell, there's not a lot of room in there.

MEMBER WALLIS: It's the other end of the pipe which when this gets out of the way the other end of the pipe is -- the wall.

MR. SHIEKH: Right.

MEMBER ABDEL-KHALIK: But these are all isothermal calculations. Right?

MR. SHIEKH: I'm sorry.

MEMBER ABDEL-KHALIK: They are all isothermal calculations.

MR. SHIEKH: These calculations are all structural calculations.

MEMBER ABDEL-KHALIK: Right.

MR. SHIEKH: I have not considered temperature in this and such.

MEMBER WALLIS: So we don't know if anyone considers this.

MEMBER CORRADINI: It depends on the -- I guess it all depends on the question you're asking. If it's an equipment qualification issue, I know for sure high energy line break equipment qualification analyses are done in great detail as to where the two phase jet load is for a particular -- But for containment analysis, it's not done for sure.

MEMBER WALLIS: It is done, isn't it?

MEMBER CORRADINI: No.

MR. SHIEKH: We considered the temperature, the overall rise in temperature. You know, like for PWRs, we have 300 degrees over the containment and then by the time it reaches the concrete the temperature only goes to 150 because most of the temperature is absorbed in the first inch or so of the concrete. So it doesn't affect the rebars and the concrete structure.

Now your question, specific question, I don't have a correct answer right now.

MR. VANDERMOLEN: It's more I would have misgivings about going into a question like that in the forum of this generic issue. That's really a more generally applicable question that would be not just for the plants that were a question of the grandfathering, but essentially for any plant that's running. So it's something that could be considered if you think it's worth investigating, but not in the context of this generic issue.

MEMBER ARMIJO: I think generic issues investigating pipe breaks in containment. It doesn't matter whether it's a structural failure or a thermal failure. Right?

MR. VANDERMOLEN: No.

MEMBER ARMIJO: But you haven't done the thermal analysis to see if you could somehow buckle the containment locally and break it.

MR. SHIEKH: I'm not sure. I mean my instinct reaction is that's not possible because the gap is only two inches for the cyclinder to buckle. You need a lot more gap.

MEMBER WALLIS: What happened to the water hammer? There was a plant. I don't think it was the Indian Point water hammer, but maybe. There was one that was the water hammer and it broke a pipe. I think it was a feedwater pipe going in as it went through containment, one of these water hammers in the feedwater line and the whole containment bulged out into -- the steel liner bulged out away from the wall.

It didn't go into the wall. It bulged the other way. It's where it could go. It came out quite a way as far as I remember. But it's a different -- It's just not your issue. I'm just asking if anyone ever considers these things.

MR. GEIGER: If I may. Irvine Geiger from Research and I'm not a civil structural engineer. But in my experience in dealing with like in a steam generator jobs where we had to replace the liner plates and so on, I do know that in PWRs liner buckling is considered especially at the stud areas and so on. So we look at buckling due to high temperature and during a LOCA.

Now in this situation and this is a freestanding cylinder basically with a concrete, there's a gap in the concrete. So as a cylinder, I would see it as being able to expand radially outward. Now maybe in localized areas you might have more expansion and you would have a larger bulge. But I don't know if that would -- you would still have that three inches or gap between it and the concrete before you would, I guess, start buckling as you might say.

MEMBER WALLIS: If it would buckle out enough to split.

MR. GEIGER: Well, if you're talking

buckling, if that area is localized and it's heating, it would have a tendency to want to expand. Correct?

MEMBER WALLIS: It comes out away from the wall.

MR. GEIGER: Well, actually it's moving in towards the wall because it's a round cylinder. Right? So if I heat a cylinder, it tends to want to expand.

MEMBER WALLIS: In the water hammer case, it moved away from the wall.

MR. GEIGER: Well, in the water hammer case, let's say you're looking at -- That was a -- You said that was Indian Point?

MEMBER WALLIS: I'm not sure if it was but it may have been.

CHAIRMAN SHACK: But it may not have been under pressure. This is the way it was.

MEMBER WALLIS: This is a feedwater line.

CHAIRMAN SHACK: No. But I mean the cylinder.

MEMBER MAYNARD: There's also a difference. If there's a PWRs containment, your liner is against the concrete. So the only way -- If the liner heats up, it has to buckle in, whereas these have a gap. So initially it would probably start out.

MEMBER WALLIS: We're speculating. I wondered if anyone had analyzed it. I would just like to know if anyone had analyzed this.

CHAIRMAN SHACK: When you heat this thing up to temperature, what is the gap size then? I mean, this thing, it's in there to take expansion.

MR. SHIEKH: It's going to that expansion without any problem.

CHAIRMAN SHACK: No, but I mean how big is the gap at operating temperature? If it's two inches at room temperature, how big is it at operating temperature?

MR. SHIEKH: It doesn't --

MEMBER WALLIS: How big is it in a LOCA?

MR. VANDERMOLEN: Remember the nominal at temperature, I think it's an inch and a half at -- Don't hold me to that.

MEMBER WALLIS: Operating temperature --

MR. VANDERMOLEN: That number exists but it is designed to be able to take that.

CHAIRMAN SHACK: Yes. No. It's just that the gap gets -- Using the room temperature gap is conservative in that sense.

MR. VANDERMOLEN: It is.

MEMBER WALLIS: But it's not very

different when you're actually -- unless you have a LOCA.

MEMBER MAYNARD: Right. The temperature is not that much higher.

MEMBER WALLIS: Right.

MEMBER MAYNARD: And also your concrete is going to be heating up too when your liner is heating up.

CHAIRMAN SHACK: That's true.

MEMBER MAYNARD: The concrete and steel are not that far apart on the thermal expansion.

MR. SHIEKH: Okay. So we are on page 19 and I'm just repeating.

MEMBER WALLIS: Well, will I ever get an answer to this or I just raised a question and it's gone and evaporated? I don't know.

MR. VANDERMOLEN: We don't know either if anybody --

MEMBER WALLIS: Can you find an answer do you think?

MR. VANDERMOLEN: We can see what we can find out, yes.

MEMBER MAYNARD: That would be a good idea.

MR. SHIEKH: I'm repeating where I stated that the containment penetration scenario doesn't appear to be credible. So at least the staff doesn't think there was a need for further laboratory action in this case.

MR. VANDERMOLEN: Further questions?

(No response.)

MR. VANDERMOLEN: Let's go on into PWRs then. PWRs are again -- it's a --

MEMBER WALLIS: No, let's go back. I'm sorry. Now if this pipe breaks outside containment and whips around, there's nothing there it damages like electrical systems or something.

MR. SHIEKH: They have already looked at all those scenarios. The only one they identified was a break inside the containment.

MEMBER WALLIS: Nothing that can be damaged by a steam line whipping around outside containment.

MR. VANDERMOLEN: That's a separate question. That was covered many years ago by the letters which put requirements in place. If there's a problem there, it's a compliance issue. But they are already --

MEMBER WALLIS: It's a different issue then.

MR. VANDERMOLEN: Different issue, but I'm not saying that wasn't addressed. It was and you'll find that some of these lines have been equipped with shields, guard pipes, vaults, things like that.

MEMBER WALLIS: All tied very well?

MR. VANDERMOLEN: Yes.

MEMBER MAYNARD: I don't know how it was handled for some of the older plants, but there was a major effort several years ago, in the '80s and '90s.

MR. VANDERMOLEN: Yes.

MEMBER MAYNARD: With pipe whip constraints and analysis.

MR. VANDERMOLEN: You'll find a reference to that in the report actually. Other questions?

MEMBER ARMIJO: Yes. The only thing I would think that if you had damaged containment by corrosion at Oyster Creek for example, I don't know how thin that cylindrical wall became from years of corrosion but you'll hear margins would be degraded.

MR. SHIEKH: Yes, but I have used only 5/8ths of steel thickness. If you have most of these areas usually at the top of the container where these are hits are, the thickness is much more.

MR. VANDERMOLEN: Okay.

MR. SHIEKH: -- if there's a small --

MEMBER WALLIS: That is more than an inch until it corrodes.

MEMBER MAYNARD: They wouldn't have much corrosion up there.

MR. VANDERMOLEN: Are you ready for PWRs?

(No response.)

MR. VANDERMOLEN: Okay. The PWR scenarios, again we're talking about something initiated by pipe whip within containment when we're talking about the pipe whip or a fluid jet which can go quite a bit further, of course, disable some system needed to mitigate that break. Again, as we discussed before, the pipes are fitted with both side restraints and pipe width restraints, other things that somewhat limit pipe whip. More importantly, the PWR containments are compartmentalized and we're not expecting that we're going to have much of a problem from the primary LOOP.

So in contrast to this, the secondary system is not necessarily separated this way and we decided that here we really did need to look and the scenario of interest here is if a pipe, a secondary --

MEMBER WALLIS: Can we go back a little bit here?

MR. VANDERMOLEN: Certainly.

MEMBER WALLIS: Don't some of these vessels have level indication, a device that measures the level in the vessel which is useful to the operators when they're figuring out if they need to put water in or not?

MR. VANDERMOLEN: Yes.

MEMBER WALLIS: Wouldn't this be broken by a pipe whipping around in there? Aren't there things that get broken besides the containment?

MR. VANDERMOLEN: Well, not just -- Certainly --

MEMBER WALLIS: Certain lines and things?

MR. VANDERMOLEN: A few of our cases. We're talking primarily about instrumentation though.

MEMBER WALLIS: They can affect the cost of the accident.

MR. VANDERMOLEN: I'm not aware of anything that's automatically initiated by those level sensors. It's one of those things where we've asked them to put in since Three Mile Island and I believe there's more than one Tap. So you would have to not likely to --

MEMBER WALLIS: Will this be looked into thoroughly?

MR. VANDERMOLEN: It has been looked into.

I can't swear to it thoroughly. I was not involved in that review.

MEMBER MAYNARD: The reactor vessel level indication for PWRs does not have any automatic actuation. That is a post accident --

MEMBER STETKAR: Boilers, it does though.

MEMBER MAYNARD: Right. Boilers, it does. PWR, it does not. I think somewhere where it's protected.

MEMBER STETKAR: Because boilers, they certainly are the instruments are located outside, but the taps are --

MEMBER WALLIS: But it's just a pressure --

MEMBER STETKAR: Right.

(Several speaking at once.)

MEMBER WALLIS: It's sort of a line that takes the pressure and measures hydrostatic pressure in the vessel. I don't know where that goes.

MEMBER MAYNARD: I don't know where that is.

MEMBER WALLIS: It presumably has to go outside containment somehow. So it has to get there from the vessel.

MEMBER MAYNARD: That's right.

MEMBER WALLIS: That's all been studied by Idaho or somebody.

MR. VANDERMOLEN: It's been studied. Okay. Your answer -- I've lost a part of your --

(Off the record discussion.)

MR. VANDERMOLEN: Are you talking about the boilers still or are you talking about the --

MEMBER WALLIS: I think we're now talking about the boilers and there's something else that can be damaged.

MR. VANDERMOLEN: In boiling water reactors, definitely the actual Yarway columns are located outside, in secondary containment, but outside the primary containment. You have to be able to get at them to maintain them. There are taps that go through down below and up the steam lines to keep them going and they are located on opposite sides. That's an important thing because you want them separated explicitly so that --

MEMBER WALLIS: One side will survive.

MEMBER MAYNARD: One side was -- The other is okay.

MR. VANDERMOLEN: Yes, and there are more than one set. There's one set used for normal operation. There's a wider range set used for accidents. I think there's a third one that goes way up and down and you use them to refuel and they're used for a lot of things. But they are definitely well protected.

The PWRs are not as -- I just don't know right off the top of my head. I've not done systems reviews on that in my own experience. If there is anybody else here that can address, speak now.

(No response.)

MR. VANDERMOLEN: But I would -- that they would have at least --

MEMBER WALLIS: If you want to give a comprehensive picture of this problem, you could say here is the space and here is the pipe and here are all the things it might hit.

MR. VANDERMOLEN: Yes.

MEMBER WALLIS: And you would show us a picture of these things and we could say, "Well, does it matter if any of these things get destroyed?"

MR. VANDERMOLEN: That's what the people at Idaho tried to do.

MEMBER WALLIS: So the people at Idaho did. We have to believe that they did the right thing.

MEMBER CORRADINI: We have to trust them.

Okay.

MEMBER ARMIJO: So this is the only thing left, mechanically left.

MEMBER WALLIS: This is the only thing that was left as a problem.

CHAIRMAN SHACK: You know, I think to put this in perspective, what they tried to do is a more probabilistic analysis. So in the probabilistic analysis, first you have the probability of the pipe break. Then you look at the probability that the pipe break will occur in a region where it could damage something. So this is all kind of laid out in kind of probabilistic terms.

What they finally came down to then was you had this thing. Then the final thing was that the containment failed when the pipe hit it and they essentially assigned a big number like 0.5. What they're really saying is even if you don't believe their analysis it certainly says that the number isn't 0.5. If it's going to fail, it's going to be some very relatively low probability.

So you don't need an absolute belief in this analysis. What you need is that this is enough to get the probability down to --

MEMBER WALLIS: So I just wonder if their guesses about the other probabilities were as bad as this 0.5.

CHAIRMAN SHACK: They were trying to make everything conservative.

MR. VANDERMOLEN: Yes.

MEMBER WALLIS: Okay.

MR. VANDERMOLEN: That was very intentional.

CHAIRMAN SHACK: It's a screening analysis.

MEMBER WALLIS: So we have to trust them unless we want to read their report.

CHAIRMAN SHACK: I have their report if you'd like it.

MR. VANDERMOLEN: We can get you the report. It is very much a matter of record.

Okay. Getting back into the PWR scenarios, here we are more worried about the secondary system piping and particularly out in the annular region in a place where it's not separated from appropriate things by walls. Now in the case of the PWRs unlike the boilers where people had the same basic design, these things vary considerably. There aren't too many general statements you can make.

CHAIRMAN SHACK: The General Electric was a variety into itself.

MR. VANDERMOLEN: Yes, it was.

PARTICIPANT: We tried hard.

MR. VANDERMOLEN: It sounds like there's a story behind this.

One thing to put this in perspective when we're talking about secondary system piping in a PWR, we're talking about a secondary pipe break, steam line, feedwater line or some smaller line like a blowdown line. The safety systems are still going to actuate on how you contain pressure. These will be pressure taps that will be connected to the containment free line but not within it. So you're going to get the immediate response. However --

MEMBER WALLIS: It would be a high containment pressure now.

MR. VANDERMOLEN: If you discharge secondary steam.

MEMBER WALLIS: Inside the containment.

MEMBER MAYNARD: If you have a steam or an OCS break inside the containment --

MEMBER WALLIS: Inside containment.

MEMBER MAYNARD: -- you'd better have a high pressure or you don't have containment.

MR. VANDERMOLEN: Yes. If there were a

hole in containment, you would absorb pressure. That's the whole idea.

MEMBER WALLIS: But it could impact IC cables outside containment.

MR. VANDERMOLEN: Again, that was covered by another issue.

MEMBER WALLIS: That was covered by something else.

MR. VANDERMOLEN: Yes. Oh, yes. Actually, that was a bigger worry because there weren't as many reviews on the outside. We did a major backfit on those years ago. So it was a lot of work and --

MEMBER WALLIS: It's like the steam line in one of those famous new reactors which is located just behind the control room as I understand it.

MR. VANDERMOLEN: That I'm not familiar with. If you have a bit of some knowledge that I can have.

MEMBER WALLIS: Okay.

MR. VANDERMOLEN: Hopefully, the operators we considered essential equipment. Next it will be routed right by the NRC Inspector's Office.

In any case, the idea here is if you were to -- What you worry about here is if you have that pipe break you may get your immediate response but you do need instrumentation for the operator to do a long-term recovery. What your operator is supposed to do is to identify the faulted LOOP, isolate it and then cool the plant down on the attack LOOP or LOOPs and if you take away some of his instrumentation or her instrumentation, you might have difficulties. So that did look like a credible thing to look at which is what we did.

Now the only way we can do that, there's no generic way of doing this, we just had to look at every plant and see what we could find. Now this has been not what I would call an intellectually challenging or particularly enjoyable piece of work, but it was a fairly extensive one.

We had looked at FSARs for every one of those plants, those PWRs. When we couldn't find what we wanted from the FSARs, we got out plant diagrams and you would be amazed at how many diagrams we have squirreled away in this building in one place or another and if we couldn't find it out from the plant diagrams, we went to our friends in NRR who assisted us by putting us in contact first with the resident inspectors and in some cases the licensee personnel to find out what we wanted.

What we looked for -- Yes, I'm sorry.

MEMBER STETKAR: Did you take advantage that all or any of the PRA models that have been built for these plants?

MR. VANDERMOLEN: Not for this, no. Actually, we had most of what we wanted.

MEMBER STETKAR: You're just saying it took a lot of research work in many cases.

MR. VANDERMOLEN: It did. This is not the sort of thing you necessarily find in a PRA. Let me show you what we did.

MEMBER STETKAR: Not in terms of the physical impacts but in terms of the functional impacts on locations in instrumentation and things. Very often, it is.

MR. VANDERMOLEN: It is, yes. But no, we really actually found we got to where we wanted without going to that step and actually we had discussed doing things like that. Let me just finish this slide and then perhaps it will be clear.

What we looked for actually first of all was there separation. Now I don't mean separation of the piping penetrations. I mean separation of the cable penetrations. We thought that if we found in a plant that there were two cable penetrations located

180 degrees apart it would be very unlikely that a single pipe break would impact --

MEMBER WALLIS: This is separation all the way around the containment.

MR. VANDERMOLEN: Yes. All the way around the equator. And short of that, the only other thing we could do is go in there and get ourselves rather well exposed tracing down every wire and we didn't think that was justified. Once more, I know I'd never get funds for that. Besides they'd make me do it.

If we didn't see that, then the question we asked of ourselves and actually of resident inspectors was if I just had all my cables come in in a single area, a single general area of the plant, if I stood there, would there be energy piping within line of sight or would there be a wall in the way or would it be too far around the curve to be a problem? We were looking for intervening walls, intervening floors, large differences in elevation which turned out to be somewhat academic. We found that in almost every case where there was a large difference in elevation there also was an intervening floor if we looked long enough. They weren't on every diagram. That was the problem.

And what we found was, you'll find an

actual table of all these plants in the report we sent you, but there were nine units that had the 180 degree separation or close to it. There were ten units that just had a single electrical penetration area but they had floors, walls or combinations. By that, I mean you might find that you were close to a feedwater line with a steam line but shielded by a floor or wall and the steam line was a distance away. That's what I mean by combination.

So there were --

MEMBER STETKAR: Let me stop you for a moment here. The nine -- And I haven't had the benefit of seeing the report. So just stop me. The nine that did have 90 degrees or greater than separation, did you make an effort to look -- You said electrical penetrations.

MR. VANDERMOLEN: Yes.

MEMBER STETKAR: Did you make an effort to look at what types of electrical cable or did you just look at electrical?

MR. VANDERMOLEN: On those, no.

MEMBER STETKAR: Because in some plants I've seen, you get secondary cables run out to a turbine building through one set of penetrations --

MR. VANDERMOLEN: I see what you mean.

MEMBER STETKAR: -- and safety related cables run to the auxiliary building through another set of penetrations, but they aren't equal penetrations.

MR. VANDERMOLEN: Actually -- Yes.

MEMBER STETKAR: They already need electrical cables and INC cables.

MR. VANDERMOLEN: Actually, we did run into that. There was one -- There were two instances I can think of. I can't remember what plants they were, but we found one penetration area that went close to a steam line and then discovered that it was carrying power for the elevator.

MEMBER STETKAR: Yes.

MR. VANDERMOLEN: So we didn't care. The other one, I believe it was power for the overhead crane. I can't tell you right off the top of my head if this also was the -- If we looked at that explicitly for the 180 degree.

MEMBER STETKAR: I was going to say it sounds like you looked at it if there was a question of interference.

MR. VANDERMOLEN: What we did do is we looked -- Actually, it's quite difficult to get this information sometimes. You'll find out the FSAR is usually listed at the piping but not the electrical penetrations. What we did discover though is we could find what was important and what was not by looking at the fire analysis. If you found fire suppression and you found two cable tunnels fully equipped, then that's what we generally found, we were reasonably certain.

MEMBER STETKAR: Okay.

MR. VANDERMOLEN: So I can't completely answer your question but that's as far as it went.

For the others if you'll totally -- up to 19 plants, there are 23 total. That leaves four the way I actually had gotten some contact with the licensee and the residents. There were two units which happened to be on the same site or at least close to them were more specific than that where we thought the things were a little bit close for comfort, but it turned out the licensee had a stress analysis which they believed said that there was a very low likelihood that the pipe if it broke would break in a location that could impact that penetration area.

There were two other units where we had a very long discussion. These two units were also on the same site but this time it was in the Midwest where we discovered that the electrical penetrations were mostly shielded by a floor, but there were some that went up. The first thing we looked at was to see wouldn't it be nice if those were elevator cables again. Well, they were not. We found out that some of them were in-core thermocouples and RTDs and pressurizer heaters.

So we got in touch first with the resident inspector and then they actually brought in some licensee personnel and discovered that, yes, there was a vulnerability there but it was only one channel of the two. The other channel was indeed below and it turned out when they looked at some of their bases document we didn't have that this was intentional because of the old general design criterion.

However, the licensee voluntarily said we should keep an eye on this and be aware of it. We will put it in our emergency operating procedures to make sure that the operator has appropriate direction just in case these are impacted by a break in that area and they put it in their corrective action program and confirmed it with a letter. So we were quite happy with the outcome there.

With that, that took care of all the PWRs and basically with that end, rather almost a year and a half of looking at these plants, not full time, but in terms of calendar time, we concluded after looking at these PWRs we really couldn't find any one of them that had a significant vulnerability and there is certainly no way we can justify any kind of backfit on them.

So overall, what our final recommendation is after having looked at the boiling water reactors and the PWRs from two different aspects, we believe we ought to close this generic issue out and we would like you gentlemen to concur in a letter for us. That concludes our formal presentation and we're ready for any more questions. I am not going to waste the silence.

CHAIRMAN SHACK: Thank you very much for a very good presentation.

MR. VANDERMOLEN: Thank you.

CHAIRMAN SHACK: I think it covered the issue fairly thoroughly. If there are no further questions --

MEMBER WALLIS: There is no subcommittee that looked at any of these reports. We just have to believe the presentation, do we?

CHAIRMAN SHACK: Yes.

MEMBER WALLIS: So it all hangs on

credibility of the presenters today.

CHAIRMAN SHACK: And your review of the document that you were provided.

MEMBER WALLIS: I was provided a document?

MEMBER MAYNARD: Emailed.

VICE CHAIR BONACA: I guess now all the later flights can take away the supports of restraints. They don't need it.

MR. VANDERMOLEN: I was waiting for a question like that.

MEMBER MAYNARD: They've already taken away some I believe.

MR. VANDERMOLEN: Yes.

MEMBER CORRADINI: A large amount.

VICE CHAIR BONACA: Yes.

MEMBER MAYNARD: I think we can also take comfort it must not be any real significant issue that took the time to get to this point which I think is another question, another issue, altogether.

MR. VANDERMOLEN: Thank you, Mr. Chair. Thank you for the compliment. At my age, I'll take any compliment I can get.

MEMBER APOSTOLAKIS: You're not blushing.

CHAIRMAN SHACK: Again, a little bit early.

MEMBER APOSTOLAKIS: What's going on today?

MEMBER MAYNARD: We're moving right along.

CHAIRMAN SHACK: We are on a break until 3:15 p.m. You're unusually quiet, George. That's what --

MEMBER WALLIS: There's no risk analysis here.

VICE CHAIR BONACA: That's right.

CHAIRMAN SHACK: Off the record.

(Whereupon, at 2:38 p.m., the above-entitled matter recessed and reconvened at 3:14 p.m. the same day.)

CHAIRMAN SHACK: On the record. We can come back into session. Our next topic is the status of NRR activities in the fire protection area and Otto will lead us through that.

MEMBER MAYNARD: Thank you, Mr. Chairman, and it's a good thing that's the topic because that's the people that we have here to address that.

(Off the record comment.)

MEMBER MAYNARD: This is an informational briefing for the ACRS. We've dealt with a number of fire protection items over the last six months, 12 months, actually longer than that. The staff has some today to provide some information, an update, on several of the areas including, I think, transition and how it's going and aspects of transitioning to NFPA 805 and where we stand with the industry on multiple spurious actuations, manual operator actions, and some other things.

So without really getting into all these items, I'm going to go ahead and turn it over here to Alex Klein and he can introduce the staff's subject here.

MR. KLEIN: Thank you very much. Good afternoon. My name is Alex Klein. I'm the Acting Branch Chief in NRR Fire Protection and as Dr. Maynard indicated, we're here today to provide you a briefing of the status of some key fire protection program activities.

Also to let you know that perhaps we might be coming to you in the near term for some additional ACRS interactions with respect to, for example, a generic letter, if we were to go back and address the issue with multiple spurious operations. If we do decide to reissue a generic letter, we would come to you for that. That decision has not been made, but I just wanted to give you an indication of some anticipated support that we might be asking from you in the future.

If I can go to the third slide, what I'd like to do is to go over the topics very briefly, let you know what we're going to discuss, and to introduce the staff who will be discussing each of those topics. With respect to 10 CFR 50.48(c), the NFPA 805 Risk Informed Performance Based Rule for Transition issue Mr. Paul Lain who is the project manager for that effort. He's a senior fire protection engineer in the branch and he will provide that briefing to you folks.

With respect to multiple spurious actuations, we have Dan Frumkin to my far left over here who is the Acting Fire Protection Team Leader relative to multiple spurious actuations and manual actions. For post fire operator manual actions, we'll brief you on where we are with that and Mr. Peter Barbadoro who is in the middle here, the Fire Protection Engineer in the branch, will provide you that briefing. And I will bring it back to Dan Frumkin who will provide you a briefing on where we are with the Hemyc and MT generic letter that was issued some time ago. So without further adieu, I'll give it to Paul here.

MR. LAIN: Okay. I am trying to remember the last time we were here. It was like April '06.

So it's been awhile since you guys were caught up on what we're doing with 805 and some of the other activities here. So we're going to do a little status, go over how the industry is doing in their transitioning efforts towards 805 and talk about a few of the lessons learned from the pilots and maybe go over sort of the list of the guidance documents that we have produced or have been produced and look at those. Next slide please.

I think the last time we reported we had 42 plants committing to transition. We still just have those 42 plants. They're at 27 sites or 42 units at 27 sites. Twenty-three are actively transitioning now which means some of the sites transitioned as fleets. So they staggered their transition so they can use the same people and that's why sort of additional sites start up a little bit later.

We are still in three years of discretion back in April of '06. We requested the Commission or the Commission approved to go from two to three years. NEI has come in and asked for additional discretion once due to the delay of the ANS fire PRA standard which we hope to have it published by December. We won't publish it but I mean ANS will publish it.

Also limited fire PRA expertise, the

industry is having a tough time finding those fire PRA guys to work at all these sites at the same time and also conduct all their peer reviews of their fire PRAs.

And also NEI was worried about, I guess, the timing of our pilots since we had a bunch of pilots coming in at the same time. So they were going to figure it out for us. So I'm looking at Mr. Riley back there from NEI. They were going to space them out for us and so we're still reviewing how we're going to go forward with that. We've have some discussion with management and the Office of Enforcement and now we seem to be going back and reinventing the wheel. But we'll get there.

MR. KLEIN: Paul, just to clarify. Excuse me.

MR. LAIN: Yes.

MR. KLEIN: You don't mean the pilots. You mean the --

MR. LAIN: No, this is actually --

MR. KLEIN: -- subsequent plans.

MR. LAIN: -- additional enforcement discretion for --

MR. KLEIN: -- for the nonpilots.

MR. LAIN: -- for the nonpilots. The

pilots, they're still on plan to go ahead and transition by next summer. I'll get into their status in a little bit.

CHAIRMAN SHACK: Are most of these fire PRAs being done by contractors rather than utility staff?

MR. LAIN: I get the feeling it's a mix. NMC, I think, is doing it with their own staff. Progress Energy is doing it with their own staff. I think Duke is using contractors and, Harry, do you know of others or Jim? I don't know.

MR. BARRETT: It's a mixture.

MR. LAIN: It's a mixture. I would like to introduce Harry Barrett. He's new on our staff. He came over from Duke Engineering and he's definitely helping us out on this.

MR. GALUCHI: This is Ray Galuchi. Even the ones that are doing most of it internally are still getting support, some sort of support, from contractors. The degree in some plants are probably getting almost all of it to their contractors. So it's a mixed bag, but I don't think there's any one site that will be doing it exclusively with their own staff.

MR. LAIN: The pilot programs have been

very busy also. We've held nine observation visits for those, week-long observation visits, the last in August. We have another one planned in November and then another one next year. Over the last six months, I would estimate that our team has looked at like a thousand pages of either procedures and calculations, the kind of things that have been sent. So we've been quite busy.

MR. KLEIN: The two pilot plants that Paul is referring to is we have the Harris plant and the Oconee plant as our two pilots.

MR. LAIN: I have to remember we have a lot of probably new members here on board over the last year and a half.

MR. KLEIN: And, Paul, when do you expect the license amendment requests for the pilot?

MR. LAIN: I have that on a later slide.

MR. KLEIN: Okay.

MEMBER APOSTOLAKIS: So you assume that the old members remember.

(Laughter.)

MR. LAIN: George, I know you have a very sharp memory. Ray tells me you remember everything and I believe everything Ray says.

MEMBER APOSTOLAKIS: I do.

(Off the record comments.)

MR. LAIN: So we've documented these visits with trip reports and we've developed lessons learned pages with those and I'll talk about a few of those in the next slide or the slide after the next slide. No, the next.

I think we have almost 50 lessons learned. I'll just go over a few.

MEMBER APOSTOLAKIS: Now this number of 42 units --

MR. LAIN: Yes.

MEMBER APOSTOLAKIS: -- has been 42 for awhile.

MR. LAIN: Yes, it has.

MEMBER APOSTOLAKIS: Nobody else seems to change their mind or --

MR. LAIN: Well, let's see. I think --

MEMBER APOSTOLAKIS: What's your impression that these were the guys who really want to try something new or they have a problem but the other guys are adamant or they're waiting to see what happens? They feel Appendix R is good enough?

MR. LAIN: I'll go over my opinion.

MEMBER APOSTOLAKIS: Yes.

MR. LAIN: With the enforcement

discretion, there was a bunch that we sort of incentivized the enforcement discretion that if you came in by December of '05 you could have enforcement discretion for your existing noncompliances plus discretion during transition. That's where we got most of the plants. I think it was Constellation that came in a little bit after that and then we got the few other plants.

With the denial of the multiple spurious actuation generic letter or with the returning back to the staff, I think a lot of the sites are waiting to see how that works out and so that's one of the big issues there. I think a lot of them are also on the fence waiting to see the pilot plants, how the pilot plants do.

MEMBER APOSTOLAKIS: So the number may go up?

MR. LAIN: So the number may go up in the future. It's quite possible.

MEMBER APOSTOLAKIS: But we're hoping it's not going to go down.

MR. LAIN: Right. The upper management and the Commission are both looking at 805 to lead a path forward in response to a lot of these issues.

MEMBER APOSTOLAKIS: Thank you.

MR. LAIN: In addition, I guess, since the last time we were here we've developed a frequently asked questions program or process and that really has come out of the pilot visits that we needed a way for the staff to be able to review certain issues and document sort of a staff position in between revising the reg guide. So we have right now, we have a reg guide that endorses an NEI implementation guidance. So the pilots are implementing the implementation guidance from NEI 04-02 and as they see changes in those, then they actually bring those to the task force and we have public meetings once a month where we look at the issues that they bring forward and then the staff will review those issues and we'll have a lot of discussion on those issues and then the staff usually writes approval memos on those issues, but those are only interim approval until the actually reg guide gets updated or 04-02 gets updated and gets endorsed by the reg guide.

MEMBER MAYNARD: At these meetings, do you get any participation from public and the industry?

MR. LAIN: I think every once and a while we'll get one of the publications but not really any other.

MR. KLEIN: I don't believe that any of

the public interest groups have shown for any of these public meetings, Paul. Is that true?

MR. LAIN: No.

MR. BARRETT: Paul Gunter called into one.

MR. LAIN: Yes. I would like to introduce Chuck Molton. He's head of our FAQ process in our staff. Yes, Chuck.

(Off the record discussion.)

MR. MOLTON: Yes. The only outside activity we've had like Harry said Paul Gunter. He called into one phone call and asked one question and that's been it.

MEMBER APOSTOLAKIS: Where is he now?

MR. MOLTON: He left --

MEMBER APOSTOLAKIS: Where?

MR. LAIN: UCS, Union of Concerned Scientists?

MEMBER APOSTOLAKIS: Sorry.

MR. LAIN: Union of Concerned Scientists.

MR. BARRETT: He left Nuclear Information Resource Services and joined -- I forget the name, but it's not UCS. He's joined some other group or formed some other group. I think he joined some other group, public interest group, but it's no longer NIRS that he's with.

MEMBER MAYNARD: That's probably not enough of a database to see whether the public sees this as a positive move or a negative move.

MR. LAIN: No. Not right now.

MR. MOLTON: Even when we have an observation visit down at the Harris plant which has had intense public scrutiny, no members of the public showed up there.

MR. LAIN: Yes. We've been having for the last few visits public meetings at the end to be able to recap what we've gone over and we have not had very much participation at those public meetings. So for transparency sake, we've been --

MEMBER APOSTOLAKIS: They don't come, they don't come. Build it and they will come.

MR. MOLTON: This was Chuck Molton by the way. That's my name.

MEMBER APOSTOLAKIS: Sorry?

MR. MOLTON: Chuck Molton was my name by the way.

MR. LAIN: So monthly we have those. Every other month it's face-to-face and then we do a phone call. Those are actually very quite productive. NEI has formed a task force for 805, an implementation task force, and I don't know if Jim wants to say anything about that task force, but I think that's been very productive at getting information to the nonpilots from the pilots. So I think it's been a great source for us to communicate with them.

MEMBER MAYNARD: Yes, that would be.

MR. RILEY: This is Jim Riley from NEI. I'll just back up what Paul said. I agree. The process seems to be going real well. Participation is good and I'll add to what I think he said earlier too regarding those that are not participating or haven't committed an 805. I think a lot are waiting to see what's going to happen here with this whole transition process before they get on board. I can also tell I think or say with some confidence that there are some that don't have plans to transition and we don't see their minds changing in the near future, too, which is something else we're going to have deal with.

But to get back to the question that Paul said and I agree with him, there have been productive meetings. We seem to be moving along pretty well. We have a change revision to NEI 04-02 coming out at the end of the year time frame and then you guys will probably be endorsing that and even moving this along.

MEMBER APOSTOLAKIS: So in about a year we will hear about the pilots.

MR. LAIN: Yes. I'll get into that in a couple slides later.

Also with the nonpilots, we have had one nonpilot workshop and then we ended up developing this FAQ process and so we haven't held another nonpilot workshop because this FAQ process is actually working very well. But we do, the staff does, attend the NEI fire protection information forum which we have in a couple of weeks and we do learn a lot from the nonpilots at that forum also.

MEMBER MAYNARD: Now the frequently asked questions, those are available to the industry and the public.

MR. LAIN: Yes, to the public.

MEMBER MAYNARD: As well as the staff reviewers.

MR. LAIN: Correct and anybody can also enter a -- If the staff wanted to make changes, we could enter an FAQ also and they usually will go through the task force to be reviewed. Next slide please.

CHAIRMAN SHACK: How long is this list?

MR. LAIN: Of the?

CHAIRMAN SHACK: FAQs.

MR. LAIN: The FAQs, I'd say we've

received 26 or --

MR. BARRETT: No.

MR. LAIN: No.

MR. BARRETT: We currently have received 28 FAQs. We've closed 16 of those.

MR. LAIN: Okay.

MR. BARRETT: So we have 12 open ones.

MR. LAIN: And since Harry was on the other side reviewing those, he says there's probably 40 to 50 of them being worked.

MR. BARRETT: I think the number is up to like 42 as far as in a working draft form.

Yes, this is Harry Barrett from NRR. I used to work for Dr. Bauer and I was heavily involved in this activity on the other side. I believe that the FAQs are up to, I think, 41 or 42 as far as the actual number of ones that are in the making. I know a lot of those have not come within the NRC but on the other side are in the process.

MR. LAIN: Yes. I think they've gotten the major ones in that they've worked hard to so they can make the next revision of NEI 04-02. They can have a resolution with the staff. When we start working on a revision of the reg guide endorsing that provision of 04-02, then they'll have their major concerns included in those.

MEMBER MAYNARD: Now just -- Is this database, this frequently asked questions, is that kept by the task force or is this the NRC?

MR. LAIN: Once they give them to us, we keep them in ADAMS open to the public to be able to see and our correspondence back and forth is all open to the public. These monthly meetings are public meetings and so we're trying to be as transparent as possible to be able to reach --

CHAIRMAN SHACK: If I put in NFPA 805, frequently asked questions, will I find it in ADAMS?

MR. LAIN: I think so. Is that the best way to find it?

MR. MOLTON: Yes. If you just put in FAQ, those three letters together, and you ordered them alphabetically, you would come down to a large block of all of these documents together.

MEMBER APOSTOLAKIS: So why would you put that FAQ in?

MEMBER MAYNARD: Frequently asked questions.

MEMBER APOSTOLAKIS: No, I know, but where?

CHAIRMAN SHACK: In ADAMS, search.

MR. MOLTON: As a title search.

CHAIRMAN SHACK: Are you going to use it now?

MR. LAIN: Because I think the Maintenance Program also has a FAQ program. So you might end up --

MR. MOLTON: Right. So does the MSPI.

MR. LAIN: MSPI, yes.

CHAIRMAN SHACK: But as long as it's a manageable number, I can weed through.

MR. LAIN: We can also give probably a list of the ADAMS numbers if you wish.

MR. MOLTON: Certainly. It's a handout at every public meeting now. So obviously, I need to find one meeting summary.

MR. LAIN: Okay. Here are a couple of the items I thought would give you a variety to take a look at. I've been corrected. I don't know if you call it PRA compartmentation or we call it boundary definition or plant partitioning, I guess. We had issues at one of the pilots where they were using sort of the imaginary walls. They were taking their turbine building and building three compartments out of it and there was not real actual partitioning.

MEMBER APOSTOLAKIS: Are these fire zones?

MR. LAIN: Well, sometimes they choose fire areas. Sometimes they'll break them down into smaller fire zones. But with the PRA guidance, they choose to work compartments in 6850 to use.

MR. GALUCHI: This is Ray Galuchi. If you look at the current standard which hopefully will be final soon they talk about they've replaced all compartments, zones and areas with physical analysis units and those are supposed to be basically self-contained areas where the effects of fire are reasonably contained by the boundaries. So this room, it would be improper to partition this room into any subareas because of fire in any part of this room theoretically, a hot gas layer could spread. Now things like weather curtains, etc., are sometimes considered acceptable as boundaries. So they don't always have to be a solid physical wall and the fact that a door was there would not invalidate this as a physical analysis unit. But that's the term that's being used now in the standard.

MEMBER APOSTOLAKIS: But it doesn't have to be a physical partition.

MR. GALUCHI: Not necessarily. It doesn't have to even be a fire rated barrier. It could only be at distance if you can argue that a hot gas layer would not be a factor because if you put up a 20 foot separation if there's no combustibles in the area then you're not going to have fire spreading along any linear direction. But if it's such where you had a low enough ceiling, you get a hot gas layer, then one could argue that physical separation is not adequate for defining a physical analysis unit.

MEMBER APOSTOLAKIS: So you say the words they're using is what?

MR. GALUCHI: Physical analysis unit are the words you'll see in the fire standard. The word compenent are 6850. Fire zones are an artiface from your safe shutdown analyses. They do not have to have any physical boundaries and what defines a fire zone is kind of arbitrary for each plant.

MEMBER APOSTOLAKIS: Very good.

MR. LAIN: So we had big discussions on how to --

MEMBER APOSTOLAKIS: So this is something that bothered you.

MR. LAIN: That was something that I guess splitting it up bothered us.

MR. GALUCHI: This came up mostly with the first pilot on Duke because -- Ray Galuchi.

Their turbine building houses all three

turbines and although there may be some locations where there's hot gas layer pockets, it's huge. And so for the purposes of breaking it up into for counting, it was convenient for them to treat them as if they were three separate turbine buildings and so for counting purposes with 68.60 counting emissions sources, they treated it that way. But for the purposes of doing fire scenario analysis, it's inappropriate to treat them as separate areas because it's continuous and you have areas where fire can spread along cable trays or oil spills, etc.

So I think the compromise that was reached with them, that compromise that they came to, is that for the purposes of counting they maintain these as separate areas. But when it comes to doing the fire scenarios, they treat them as one continuous area. So it's kind of a -- It's a unique feature at the Oconee plant. Some of the older plants will have this same problem.

I know thinking back to my Ganee days there is very little physical separation in some of these units. Some of the BWRs, too, have huge areas in there. So it would be inappropriate for them to break these down into separate units for fire scenario analysis. But it's probably acceptable to do so for the purposes of counting. They have to, the peer reviews will have to look at this and make sure that depending on what they did that you can't look at the task on compartmentalization or partitioning and the task on fire scenario analysis separating. You have to look at that as an integrated package.

MEMBER APOSTOLAKIS: Very good. Thank you.

MR. LAIN: The next bullet on ignition frequency database, I think, from some of the 6850 guidance there were some questions on how do you count electrical cabinets since they come in so many different sizes and shapes and some of them are partitioned. Some of them don't have dividers in between them. So we came up with some very definite, more information on how they should count those.

6850 I guess was a little bit thin on how do you count high energy arc components, whether they should count MCCs.

MR. GALUCHI: These are specifically FAQ 16 through 18 which are addressing concerns like this as to just if you had a single cabinet but it happened to be 15 feet wide, would you count that as one cabinet as if you had five cabinets three feet wide and they were altogether? Does one of them deserve being counted as one cabinet and the other deserve being counted as five cabinets in vertical sections? So 6850 wasn't necessarily clear on that. So guidance was needed because the different pilots were approaching it in different ways and that's an example of the successful FAQ where the 6850 authors went back, reviewed the issue and came up with guidance that hopefully will be incorporated into the next revision of 6850.

MR. LAIN: And then the other high energy arc component which is bus ducts.

MR. GALUCHI: And that's still under development.

MR. LAIN: How do you slice up bus ducts and count those? So that one is still being worked on.

MEMBER APOSTOLAKIS: Speaking of cabinets, we had a very interesting problems in the old days of PRG. It was a cabinet where they had three or four fires over a period of two weeks.

MR. LAIN: The same cabinet, yes.

MEMBER APOSTOLAKIS: The same cabinet and then they replaced it with a new one. Now what is your evidence? Zero fires? One fire? Three fires?

MR. LAIN: Right.

MEMBER APOSTOLAKIS: That's a tough one.

MR. LAIN: And I think they end up looking at things from an aggregate and they've gone from instead of an ignition source frequency from a large area while down to components. So you're trying to count the components and how you divide it up.

MR. GALUCHI: It's a mixed bag. There is still some area wide type frequencies. But where possible, they've tried to take it where you do a plant wide count and then you apportion it.

MEMBER APOSTOLAKIS: So this database is really component focused.

MR. GALUCHI: They try to be as much as possible but there are things like cables, etc. There's still you break it up by the cable loadings and transients are high, medium and low amounts of transients. There are still qualitative words in on some of this.

MEMBER APOSTOLAKIS: In the early days it was areas.

MR. GALUCHI: Correct.

MEMBER APOSTOLAKIS: Now it's really trying to be components.

MR. GALUCHI: There are some areas. Where possible, they've gotten away from areas and gotten to components. But in some cases, they haven't been able to do that.

MEMBER APOSTOLAKIS: Is this EPRI database?

MR. GALUCHI: Yes. It's exactly what's in 6850 right now. If you look at Appendix C of 6850, you will have a list of all the fires that are counted in that database and I mean, the plant names have been removed, but you can -- I think there's something on the order of something about 1,500 fires that are deemed as challenging fires that they retained for the purposes of frequency calculations. How many fires there are altogether, I'm not sure. But the ones that are -- And there's criteria that the 6850 authors use to define what is considered challenging. But there are about 1,500 of those in the database.

MR. LAIN: And they've moved away from the NRC RES database.

MR. GALUCHI: The Jim Howten database they did not -- Although he worked with the same data that EPRI worked with.

MR. LAIN: Moving forward with the EPRI.

MR. GALUCHI: He did his own screening and his own definition and did some statistical enhancement where he thought necessary. The 6850 does not use that process.

MR. LAIN: Okay.

MEMBER APOSTOLAKIS: What's the condition of the probability of hot shot?

MR. LAIN: As high as 0.6. Otto would like -- Dr. Maynard would like me to get through this. We could get stuck into this and have a good conversation all day long I think.

Configuration control, they said that's totally essential to be able to do all this cable tracing and then also carry that post transition and be able to keep track of all the changes. So they noted that that's essential.

The Appendix B tables in NEI 04-02, those were the tables that were going to be submitted in their license amendment request. They've noted they needed to modify those a little bit to capture the data a little bit better.

Low power shutdown review, 805 or Appendix R only is for at-power. 805 makes you look at all operating modes. How they were going to handle low power and shutdown was basically look at the HREs, the high risk evolutions, and what they were doing is they were taking the pre-existing high risk evolutions and we were worried that they were going to miss some of the fire induced high risk evolutions. So we're still having discussions with them on how to make sure they capture all of the evolutions we think they should.

So this is sort of a sampling. The trip reports have I guess almost 50 issue summary sheets in them. So they're a good thing to take a look at if you get a chance. The next slide please.

I missed one here on carrying forward existing licensing basis. That's one of our latest issues we have. Some of the licensees have unique issues in their current licensing basis. Progress Energy at Harris, I think, says no inter-cable hot shorts are possible. Duke has no multiple spurious for the first 20 minutes.

MR. GALUCHI: Ten.

MR. LAIN: First ten? Ten minutes.

MR. GALUCHI: Harris is just for -- It's, I think, thermal set intercable.

MR. LAIN: So our discussion there is that they basically need to go back and evaluate those and make that those are credible assumptions that they can make and carry forward. Next slide.

So the pilots, we have two more observation visits, one in November and one in April. But in between there, in January through March, we're going to be doing staff reviews of the fire PRAs and basically what we're taking is NEI has produced a draft fire PRA peer review guidance. So we'll be piloting that review guidance. We'll be taking the new ANS fire PRA standard and using that and actually going through doing a couple of weeks of review of the documents and then actually going and looking at their fire PRAs.

In the future, the nonpilots, we expect them to do the peer reviews between the plants. So we're going to essentially do the peer reviews for the pilot plants.

MEMBER APOSTOLAKIS: Which ones are the pilots again?

MR. LAIN: Harris, Sharon Harris, and Oconee. That's the Progress Energy plant from Raleigh and then Oconee's in Seneca.

Let's see. So the pilots are on schedule to present us their license amendment request submittals in the middle of next year, May and June.

MEMBER MAYNARD: How long are you anticipating for the NRC review of those submittals to take?

MR. LAIN: We're expecting six months. Right now, we're scheduling six months.

MEMBER MAYNARD: Okay.

MR. LAIN: So by the end of '08, we should have some safety evaluations but I hope we have a couple of plants ready to go.

Right now, they're scheduled in the November-December time frame, nonpilots. There are 12 nonpilots that will be coming, be completing their submittals. We figure they'll be completing their fire PRAs by next spring. So they'll need to conduct their peer reviews in the summer time frame and I guess if they don't get additional enforcement discretion they're going to be rushed to do that. But right now, they're scheduled to -- Their enforcement discretion runs out in the November-December time frame. So we're expecting 12 by the end of the year, but in fiscal year '09, we're expecting 17 actual sites to come in. So that will keep the staff pretty busy.

MEMBER MAYNARD: The discretion period for these plants, is that for them to make their submittal or for them to get the submittal approved?

MR. LAIN: Actually, it's three years to make the submittal and then it continues on while the NRC is reviewing their submittals.

MEMBER MAYNARD: Okay.

MR. LAIN: They'll have discretion. We didn't necessarily put a time length on our review but there's internal time constraints that the NRC goes by and usually if it goes over a year, I think it starts sending up signals. Next slide please.

So some of the 805 guidance that has come out, I guess, since the last time we were here and you guys have seen probably the NUREG-6850 and that's developing of fire PRA methodology. NUREG-1824 is the fire modeling V&V, verification and validation, effort they did. They took five fire models and put them through an ASTM standard, I think, on verification and validation. So that was very informative. Both of those documents are about 700 pages long. So they're quite complete.

We just issued a regulatory information summary on the FAQ process 2007-19. That's sort of standardized how we're going to do the process. NEI fire PRA peer review guide, we have a draft of that out and I think we're expecting another completion after the ANS standard is published. Is that right, Jim?

MEMBER APOSTOLAKIS: What is the status of the ANS standard?

MR. GALUCHI: It has been -- The ANS RIS

committee declared consensus. So it's been sent to the ANS standards committee for final vote and hopefully approval. It's also been sent to the ASME. So it can be integrated into the combination standard that will come out and be endorsed in reg guide 1.200 sometime next year.

MEMBER APOSTOLAKIS: Good.

MR. LAIN: So that was about a year delay, I think, on what we were expecting a couple of years ago.

MR. GALUCHI: I think the final --

MR. LAIN: It was handed out by the end of last year.

MR. GALUCHI: I think the final, the peer review guide, is supposed to come out by the end of this year. It's a process document. And so the supporting -- the actual technical review elements, etc., are in the standard itself. So the peer review guide is not limited by any minor changes in the technical elements. It talks about the number of people on the peer review, the qualifications, the scheduling, etc. So I think NEI plans to have that out by the end of the year.

MR. LAIN: We're expecting the implementation guidance document from NEI 04-02 to be revised in the December-January time frame and then after that, we'll be working on a revision to the reg guide 1.205 which will go through the committee to go forward for review.

We are working on the 805 SRP now and we're going to pilot it through the pilot plants next year. So by the end of that, we'll be ready to put that through the process to have that as a risk-informed fire protection SRP.

And next year, we'll be working on post-transition inspection procedures. Right now, we have inspection procedures for during transition. So during their triennials, they'll use a special inspection procedure and then we'll be working on -- That's probably our last document to pull together is that post-transition inspection procedure. That will be ready for the plants. I think the pilots have been talking about maybe piloting that transition because I think they're triennials are next fall. So we'll be looking at maybe piloting that inspection procedure with the pilots also.

Any questions?

MEMBER MAYNARD: All right. Thank you. I'll point out that we're about halfway through out time and through one of the four topics. However, I think it's the surprising that this one would generate the most discussion.

MR. LAIN: Last time it was the least one.

MR. FRUMKIN: I'm Dan Frumkin and actually we planned that about half the presentation would be 805 and then a quarter of the presentation on each of the other topics and just a few seconds on the Hemyc.

I'm a fire protection engineer in the Fire Protection Branch and I'm going to be talking about the multiple spurious actuation issue. I'll talk about the background, highlights of NEI's multiple spurious actuation resolution methodology and NRC has corresponded with NEI on their methodology, we had a meeting today which I'll touch on a little bit, what some of the views of the NRC had and the next steps that we foresee on this process.

Just a little bit of background. The NRC proposed a generic letter requesting licensees to confirm their compliance with multiple spurious in light of the relatively high probability of multiple spurious actuations that have been identified during various testing programs. The staff proposed that to the Commission. The Commission disapproved issuing the generic letter at that time based on the fact that -- part of the reason was there was not a clear deterministic process in the generic letter for the licensees to follow. That's discussed in the SECY-06-196 and we've been meeting with NEI continuously since February to discuss a method to resolve this issue and again today they presented the detailed methodology of their method.

MEMBER MAYNARD: That was at a meeting here this morning.

MR. FRUMKIN: That was in the meeting this morning, yes.

These are some of the highlights of the NEI's multiple spurious actuation resolution methodology. They intended to come up with a generic list of multiple spurious actuations that should be looked at and they are going to use or intend to use system interactions developed by the owners' groups. They also intend to use risk information based on the NFPA 805 pilots and any other fire PRAs thare are available outside industry at this time.

Their proposal only addressees III.G.1 and III.G.2 which is the very deterministic separation parts of Appendix R to 10 CFR 50. The more performance based section, III.G.3 and III.L which has performance criteria is not discussed specifically because of the complexities of dealing with the multiple spurious actuations for rooms like the control room or cable spreading rooms where anything could be affected by a series of hot shorts. And the technical aspects of the framework would be applicable to all non 805 plants. So that's their proposal. Their intent is to come up with a way that meets the Commission's goal of resolving multiple spurious actuations outside of NFPA 805.

VICE CHAIR BONACA: Just a question I have here. You seem to talk about a generic effort.

MR. FRUMKIN: Yes.

VICE CHAIR BONACA: But imagine that multiple spurious actuation is very much a plant-specific issue the way you address it.

MR. FRUMKIN: Right.

VICE CHAIR BONACA: Are you planning to --

MR. FRUMKIN: The generic effort is to -- As we were informed this morning, NEI is doing a survey at the highest levels of their management to make sure that they get results to identify all the multiple spurious actuations that have been considered by plants. They're going to assemble all of this meta-list and use that as the generic list and then licensees will in general take from that list and exclude items that don't apply to their plant. In some cases, there may be some plants that don't put input into this large list and they will actually be adding additional plant-specific items.

VICE CHAIR BONACA: That is to get the comprehensive list.

MR. FRUMKIN: That was my understanding this morning. Jim Riley is here from NEI. He can clarify.

MR. RILEY: This is Jim Riley again. Just a couple of clarifications if it's okay. One, this methodology would also apply to 805 plants. I think the difference is where the 805 plants are with respect to completion of the methodology. This development of the generic list of multiple spurious is going to take longer. The pilots will be into this process before we get to that point. But the rest of it really kind of applies to them too.

The generic list as Dan indicated would be made up of basically all the sources we could think of to collect information on what's being considered out there for multiple spurious from individual plants, from their safe shutdown analysis, from RIS insights, from PRAs and all those things. That would then be sent out to use under the methodology.

But one other aspect here, when the plants use this generic list to evaluate their own multiple spurious at their site, they not only look at what's in that list and are able to justify some of the MSOs, we use that term, as not being applicable, but they also look at their own particular situation and add more into that list that may not have been in in the first place. So it comes both ways. They can add to the list. They can delete from the list. And the process takes place through an expert panel kind of an approach.

VICE CHAIR BONACA: Okay. Thank you.

MR. RILEY: You're welcome.

MR. FRUMKIN: When I made these slides, I didn't have the benefit of this morning's meeting. So there is a little bit more information that's not here in the slides.

Some of the comments that the NRC had through some of our letters is that the industry proposed methodology includes consideration of risk in determining compliance outside of 10 CFR 50.48(c) and the Commission's direction to the staff is to encourage licensees to adopt 805 as a risk-informed fire protection licensing basis. So the staff is challenged with finding the place between 805 and the deterministic licensing basis understanding that there's no deterministic licensing basis that can completely be devoid of risk insights, but how much can those risk insights be applied before you say you're too much like NPFA 805 and that's the path you should take. That's the staff's challenge.

MEMBER ARMIJO: Has the staff's assessment of the methodology been impacted by either current or past research that's been conducted by the Agency, for example, the Carroll fire project?

MR. FRUMKIN: The methodology is in my opinion just from hearing about it this morning very consistent with the methodologies that are available as part of NFPA 805, as part of NUREG-6850. So the methodology uses a lot of the tools from and it's informed by the fire modeling. They tend to inform it through the fire modeling research.

So based on the state-of-the-artness of the method, it seems to be using the best information available. I think we heard today that they intend to -- Well, I don't know if you want to discuss Carroll fire. I notice Jim stood up. So maybe he wants to --

MR. RILEY: Yes. Jim Riley again. Just a thought on the Carroll fire, we did talk about that actually after the meeting today and decided that by incorporating the results of Carroll fire and the other recent testing into the methodology, there's an appendix that talks about how you take this what could be very large list of multiple spurious and start whittling it down to something that's more manageable or more realistic. We would use the results of those tests to help with the deterministic evaluation of which of the MSOs are things that we do need to consider. So, yes, we will be incorporating the observations, the results, of the Carroll fire and other tests into our methodology.

MEMBER ARMIJO: I'm just trying to understand how long it takes for that information to filter down and have an impact.

MR. FRUMKIN: Well, Mark Sally from Research is here and he can give us the status of the Carroll fire report.

MR. SALLY: Yes. I can. Mark Sally, Office of Research. Carroll fire had just completed public comment. As you would expect, NEI had a number of comments for us to take a look at on improving the document. We are planning to come to you probably in the December time frame with the final Carroll fire document and the public comments to show you what the document looks like and ask you for a letter to publish it. So that's where we're at with Carroll fire right now.

MR. FRUMKIN: Thanks, Mark. And following the publishing of that, the NRR staff will consider how it will impact inspection procedures. We have a RIS out currently that summarizes some of the -- or a RIS called for Carroll fire in a way and all the questions that the Carroll fire answered are in a RIS as questions. So we need to disposition the results. But that hasn't been determined how we plan to do that at this time.

Some of the points that we've had with the NEI methodology is since it's a focused application, we do have some questions about the cumulative and synergistic effects because it's not planning to be -- or in how they will be handled by an expert panel because it's not going to be a full-fire PRA. It's their methodology is not going to require a full fire PRA.

We want to ensure that when the fire PRA methods or tools are used that they're of adequate quality because some of the parts we'll use, like I said, are 6850 methods. So we want to ensure that when 6850 is used that it's being used in a way that's consistent with the level of quality that NFPA 805 plants are doing it and there's a need to consider multiple spurious actuations in III.G.3 areas. These are the performance-based type areas.

We have the NRC staff and the NEI in the middle of a dialogue. As I said, we met today. We're going to be discussing these things quite a bit and the -- See what the next slide says.

So the next step is and we're going to continue to engage the NEI and again, we've been directed by the Commission that the NFPA 805 for 50.48(c) is the Agency's risk-informed, performance-based fire protection rule and we have to navigate the rules and the technical issues in order to come to some conclusion. This is really a work in progress. I can answer questions, but I'm not sure. I mean, we have all the right people here to answer them, but I'm not sure how far we can go in the details of this question.

MEMBER MAYNARD: I'm encouraged that the industry and the NRC are communicating and working to find a reasonable solution to this issue and I think it's in both the industry and the staff's best interest to come to some agreement as to an approach and a way to do this. I think the Commission sent a pretty clear message that they didn't want some open-ended thing that would not be able to be implemented or whatever. The industry has moved off of their position of we don't need to do anything and I think that the cards are coming out right for the staff and the NEI and the industry to work together on a solution to this. I think it would be the wrong thing to send something else up to the Commission that is totally adversarial or there is no buy-in from anybody.

VICE CHAIR BONACA: I'm just trying to understand from a list of examples that have been determined how do you convince yourself that you have a complete, or not complete, as complete as possible that possible actuations have been considered to that of significance.

MR. FRUMKIN: Yes, and for the III.G.2, for the deterministic sections, we spent a lot of time in our meeting today discussing how we were going to handle multiple spurious actuations. But the bulk of the work is defining what train is free of fire damage and when that train has been identified, then we only have to determine the multiple spurious actuations that can affect that train and that, I'm not saying it's a trivial amount of work. It's a significant amount of work, but it has -- It's bounded --

VICE CHAIR BONACA: The logic behind it

that drives it. Okay.

MR. FRUMKIN: Right. So within that train, that's what you're looking for. There are other issues that can affect safe shutdown. But within the text of Appendix R, III.G.2, if it doesn't affect that train and affect safe shutdown through some other means like an opposite train pump starts, the licensees even there have more flexibility.

MEMBER MAYNARD: Any other questions?

MR. WEERAKKODY: Yes. I just wanted -- This is Sunil Weerakkody. The question you are raising in terms of the plant's specificity and as to how plant-specific fire PRA can very well capture them but not necessarily a general list that's combined, that has been a staff concern. So you cannot -- If you're not getting a direct answer, that's kind of very tight one of the challenges that we have had in coming to a consensus with industry on this issue and one of the other things and this is at the next higher level I am sure this committee has had other presentations on Agency's far forward on face approach to PRA quality. So when we bring 805 in and seek a solution to the 805 program through the use of PRA from a consistency, coherency, staffing, resources point of view, we have to look at is 805 or any other risk-informed approach being said to align with those high level plans. So there are some major challenges. We're not sharing them with you today because it's a work in progress. But we have issues like that. Thanks.

MR. FRUMKIN: Okay. I will pass it over to Peter.

MR. BARBADORO: Good afternoon. My name is Peter Barbadoro. I'm a fire protection engineer in the Fire Protection Branch and we'll continue to talk about Appendix R, III.G.2 in regards to operator manual actions and what I'd like to speak with you about and bring you through is the three items I have listed on this first slide and the first is the SECY SRM in regards to the closure plan that was put together when the proposed rule was actually withdrawn and the status of the NUREG-1852 which I believe you're mostly familiar with recently and that review and where that is and then maybe just some quick final remarks and questions that we have. You can flip the slide.

In February, I think it was, of 2006, the proposed rule was actually withdrawn and the closure point in the items that are listed, actually that follow that bullet, in regards to the standard review plan and the inspection procedure and the reg guide, I'm sorry, the regulatory issue summary, the RIS, that was issued.

The standard review plan has been updated. It's a rev 5. It provides a reference to actually the reg guide, the 1.189. The reg guide does have a relatively strong section in regards to operator manual actions and expectations in Section 5.3 of that reg guide. In addition, the closure plan had focused on the inspection procedure which is utilized for the triennial inspections for fire protection and also the annual and quarterly, I believe, or was it just the triennial? It was just the triennial I think. Excuse me. And that was also revised to clarify the position in regards to operator manual actions that focused on compensatory measures which is a short-term fix I guess you could call it for any fire degradation that would be present. In addition to that, the RIS 2006-10 was issued and is very detailed in regards to the compliance expectations for operator manual actions in addition to, I believe, speaking to the option of 805 is that's an option for the licensees.

And just in the continuous reactor oversight process, obviously, we continue to look at compliance with the regulations and commitments at all the different plants and we see those come in as an ongoing effort obviously in regards to operator manual actions and I think the enforcement discretion is just about to expire in regards to licensees having to have any OMAs in their program, in the corrective action program, at this point in time. I think it's September 9^{th} or something.

MR. KLEIN: It's today.

MR. BARBADORO: Is it today? It's today. How timely. And that's where we are basically with the closure plan. In addition to that, the next item we're going to talk about which is part of the closure plan because we were asked to develop some internal guidance for the staff and that is the NUREG-1852 document which addresses performance of post-fire operator manual actions and I think most of you have seen that quite a bit lately.

So where it stands right now, as you know, it's been through the ACRS. It's been to CRGR just recently and we are waiting for some final recommendations to come from CRGR to go ahead and make some minor changes, I think, in some wordings, some specific words, that they asked us to look at. So we're looking at that right now and hopefully we're going to publish the document soon and I believe this committee has supported that in the last meeting.

And just quickly as some final remarks that we have listed here is we do expect the licensees to bring OMAs back into compliance as described in the RIS that was published in 2006 which provides a lot of guidance to the expectations and their options to the regulations. 1852 was an important document to us as you know because it is our document that we're going to utilize for license and actions in the future in regards to OMAs in III.G.2 space.

MEMBER MAYNARD: Now 1852 is primarily guidance for the staff on how to disposition exemption requests that come in.

MR. BARBADORO: Yes sir.

MEMBER MAYNARD: Has there been much discussion with the industry? Do you expect many of these? Do you have any feel for what to expect relative to this?

MR. BARBADORO: I don't specifically have any feeling with regards to the number of exemptions. Alex may have a better --

MR. KLEIN: We have not heard the exact number of exemptions that may come in. We do have one licensee that's about to submit a group of operating manual actions that they would like to use in lieu of the III.G.2 requirements. We have not yet seen that licensing action. Nothing is on the docket yet. They're proposing to hold a pre-submittal conference with us tomorrow as a matter of fact. So they will be faced with the first ones coming in to request, after the rule was withdrawn, to request use of operating manual actions in lieu of the requirements under III.G.2. So we've yet to see what they want to request.

MEMBER MAYNARD: Do you have any indication of what's going on out there as far as -- You may not know exemption requests coming in but are plants changing their procedures, processes and designs to come into compliance where they're not going to have to coming up with exemptions?

MR. KLEIN: One of the closure plants that Pete had mentioned was this enforcement discretion and when we were through the proposed operating manual actions the Commission approved a certain time period for licensees to bring themselves back into compliance if they have a noncompliant use of operating manual actions and what the Commission approved was a certain date by which licensees must identify the noncompliance operating manual actions, initiate those corrective actions and implement compensatory measures.

That enforcement discretion actually ends today. They then have a certain amount of time which ends March 6 of 2009 by which time they must have completed those corrective actions. So licensees have basically until March 6 of 2009 to bring themselves back into compliance and complete those corrective actions for those operating manual actions.

MEMBER MAYNARD: Okay, and can requesting an exempt be one of those corrective actions?

MR. KLEIN: It is. In the regulatory issue summary that Pete had mentioned, we had outlined certain options for licensees to utilize. Of course, the preferred option is compliance on the III.G.2.

MEMBER MAYNARD: Right.

MR. KLEIN: We also outlined the fact that they could adopt a new licensing basis under 10 CFR 5048(c), the NFPA 805 and some of those plants have elected to go that way. And then the other option, of course, is through a licensing action such as an exemption request if they so desire for the pre-1979 licensees. For licensees that were licensed to operate after January 1, 1979, those licensees have a little bit more flexibility to change their fire protection program relative to use of operating manual license and all that is discussed in that regulatory issue summary.

So we don't have an exact number.

MEMBER MAYNARD: And I wasn't asking for a number. Just to feel that there are things going on out there.

MR. WEERAKKODY: I would like to add one remark there in terms of what's going on out there. What we can comment is what's going on out there with respect to our inspection process. We have had in our recent workshops instructors with the inspectors have basically told them that they need to specifically go look for whether the licensees have identified their noncompliant operating manual actions and put them in the corrective action program. As a result, we have had instances where inspectors would call us, get our feedback and then do the enforcement appropriately.

MEMBER MAYNARD: All right.

MR. BARBADORO: Were there any other questions?

(No response.)

MR. BARBADORO: Thank you.

MEMBER MAYNARD: Okay. Thank you.

MR. FRUMKIN: Okay, and this is the last topic and last slide. So we have plenty more time to talk on 805 default. The Hemyc and MT generic letter, on April of 2006, we issued a generic letter requesting information regarding the brand named Hemyc and MT fire barriers. The Hemyc is a one-hour fire barrier and the MT is the three-hour fire barrier. All the licensees responded in accordance with the information request.

MEMBER MAYNARD: I think we have copies of the slide in front of us here.

MR. FRUMKIN: Yes.

MEMBER WALLIS: We can go on.

MR. FRUMKIN: It's very disconcerting. Of these 16 licensees, 16 units, nuclear units, that had reported having Hemyc, ten of the licensees are resolving their Hemyc or MT issues through adopting NFPA 805 or committing to adopt NFPA 805.

One licensee removed their Hemyc and replaced it with a different fire barrier. Three licensees are requesting or have requested exemptions from the requirement of the one-hour barrier. I believe two of those licensees have been approved, the exemptions are approved and one is still being processed, but we've been through the RAI process and the staff doesn't have any additional questions. And two licensees use the Hemyc as a radiant energy shield. So they reported having Hemyc but they did not report that it was for one-hour rated fire barrier. So they've done analyses to ensure that it's going to meet their commitments as radiant energy shield.

All the licensees had to respond regarding other fire barriers and all of them have and I think we have acceptable information from all of them. But I don't believe -- I think we're over 90 percent closed out, but we have not closed out all of them. But I don't think we have any more questions for licensees on these issues.

So we should have a solid point in time, a snapshot, where all the licensees have reported that their fire barriers are good. They've given us some detailed information and we have reviewed it and agreed at least that their characterization of their fire barriers are acceptable. But we have not gone out and inspected them or verified in the field anything. But at least we're again, through the discussions with the licensees, on the same page with what standards fire barriers are supposed to meet.

MEMBER MAYNARD: Could you just go back over Hemyc and MT, just what's --

MEMBER ARMIJO: What's the issue? I was

asking the same question.

MR. FRUMKIN: Okay. Sure

MEMBER ARMIJO: Is something wrong with the material or the way it's used?

MR. FRUMKIN: Okay. The material, the Hemyc material, it's a kao wool, a ceramic fiber that's surrounded with a fabric, a fire resistant fabric, Siltem or Refersil. It's a welding fabric and depending on how it's configured, it's either an inch and a half thick or two inches thick of the ceramic fiber.

The NRC has done small scale tests of this material and it lasted in the small scale test about 20 to 30 minutes. In actual configurations in the field, it's much more robust than the small scale test. But it has lasted not in actual testing configurations, full-scale, it's lasted anywhere from 20 minutes to an hour for the one-hour material and that was how it was nonconforming. The licensees, the rules that the licensees committed to an hour fire barrier and by every measure that the NRC can determine this barrier didn't last.

MEMBER MAYNARD: It didn't make it.

MR. FRUMKIN: The MT material is similar to the Hemyc material in that it has the Siltem and the fire and the ceramic fiber bat, but it also has some hydrated silica salts that as it heats it steams. So it has quite a very -- It's very robust for fire resistance. But again, due to this material's thicknesses and also due to this phenomenon where when you take the Siltem to very high temperatures it shrinks, the MT material failed as well under full-scale fire conditions and under the three hours that were required.

MEMBER ARMIJO: It's amazing. It wasn't tested beforehand when the material was qualified.

MR. FRUMKIN: Yes, it was tested. But this was in 1982 and I believe one of the other committees had -- Well, it was tested in 1982 in accordance with ASTM E-119 which is a very severe fire testing standard and one of the committees at the NRC determined, it wasn't the ACRS, I can't remember, the judicial board, I think, that if you can pass that test you're good. So it's a very severe test. But it was done in Spain under the Spanish nuclear people's quality assurance and I think there were some differences between the way it was installed in the testing and the way it was installed in America that accounted for -- And when it was tested there it lasted for an hour. It was close, but it lasted for an hour. But I think the differences between what was tested in Spain and what actually happened, how it was actually installed in the United States, accounted for some significant differences in performance.

MR. WEERAKKODY: Dan, excuse me. Yes, the Research, Mark Sally is the Branch Chief for Fire Protection, they did the testing here. This was several years ago. So I was going to ask Mark to really jump in.

MR. SALLY: Let me give you a quick synopsis for those who haven't been through the Hemyc. Dan is correct. The Hemyc material was used in Spain. Hemyc is actually the name of a Spanish insulation company. That's where it came from. The materials really used in a plant over in Spain and they had done some small scale testing. But the Spanish regulator always had some questions about it. So the Spanish did something a little different. They installed it but then they added extra sprinklers, etc.

Nevertheless, the material came to the United States and you see a small percentage of plants did use it. The thing that Dan was getting to is the outer covering. If you picture a pillow case, it's basically what it looks like. They install it in what's referred to as mats. You sew it up in those pillow case sizes and then you wrap it around a cable tray, conduit, junction box, what have you. It all assembles real well and then they stitch it together.

The phenomena we saw which was a new phenomena that came about was when we did the full-scale confirmatory testing is that the outer layer shrunk up and when it shrank it pulled the seams open. So we saw failures as early as 15 minutes and some did last out into the 40 minutes or so.

MEMBER ARMIJO: Maybe the right stitching might have made a difference, different stitching.

MR. SALLY: Actually, they used a noncombustible thread and they did try different methods of stitching. But the material shrunk so violently that it literally pulled itself apart. They even went as far as to use fender washers and quarter 20 knots and it would literally rip it apart. Yes. So this shrinking is quite dramatic.

And it's interesting. Hindsight is 20/20. When you talk to people who are experts in fabrics and like Dan said the big commercial use for this is welding cloth. You see it if you're going to weld in a plant in an area. You cover up equipment with this cloth. That's the outer layer of the Hemyc barrier is that you can buy it in two forms, preshrunk and not preshrunk.

MEMBER MAYNARD: Nobody knew about preshrunk.

MR. SALLY: Yes, and then the thing was when they installed it and the vendors did is they did not buy the preshrunk material. Like this, the people in the industry, the cloth industry, this is common knowledge to them. To everybody else it wasn't and when we pulled the string as to why didn't they use the preshrunk and you wouldn't have that phenomena, it was the idea that it was a lot harder to work because they shrink it by putting it in a furnace and heating it and it makes it harder to work. So that's basically the Hemyc story.

MEMBER ARMIJO: Thank you.

MEMBER ABDEL-KHALIK: What were the bases for granting those two requested exemptions?

MR. FRUMKIN: The bases were that the Hemyc did have in the configuration that it was installed it did have some residual fire resistance whether it was, I think, 24 minutes or a half an hour and that the areas were either met a certain threshold in defense-in-depth which is either low combustibility fire suppression systems or even if the fire were to occur that they would have the capability of shutting down. So we used that defense-in-depth characterization to justify the exemption and I think one had a lot of suppression and very little combustibles and the other two were in a plant that had very little combustibles. Their cable was asbestos-sprayed cable. So it's very robust and very flame resistant and also they had some significant fire suppression in the area.

The plants, it's Fitzpatrick, I believe, is one and Indian Point 2 and 3 are the other two. So those are the plants and all the information is available in ADAMS except for the one Indian Point plant that is still under review.

MEMBER POWERS: What does resolving the Hemyc and MT issues through the NFPA 805 entail?

MR. FRUMKIN: The plants, maybe Paul can answer this as well, will evaluate the capability of the barrier, evaluate the hazards in the area and determine either through a fire modeling path that the cables wouldn't be damaged and in fact they might screen out or through PRA in determining some likelihood of failure under these certain fire scenarios they would come up with a fire frequency and if that met a certain threshold, then they can justify defense-in-depth and safety margins. They could also have a less than one-hour rated barrier.

MEMBER ARMIJO: So these people think they can -- Has anyone actually done that, dispositioned it by doing the --

MR. LAIN: We haven't seen those yet, as of yet. Ray, were you going to jump in?

MR. GALUCHI: Ray Galuchi. I presented a paper at ANS last year where I did an analysis showing that even with integrated conditions as far as not being able to maintain the one-hour fire rating that it's unlikely that Hemyc for the types of fires that are typically encountered at the nuclear plants that you will see much -- that you'll see greater than 10^{-6} CDF for Hemyc.

MR. FRUMKIN: Right, and part of that is when we get back to the ASTM E-119 time/temperature fire exposure is very severe. It reaches 1900 degrees in about 15 minutes or so. The types of fire exposures that we generally see in the fire modeling are -- Or I think many, a couple megawatts is the fire of ASTM E-119 and most of the fire exposures we see, sort of these high energy arcing fault instantaneous exposures are about 650, 370 megawatts or kilowatts, you know, order of magnitude smaller, maybe even two orders of magnitude smaller than the exposure that happens in the furnace.

MEMBER POWERS: Can we have a model that predicts how a Hemyc will be made?

MR. FRUMKIN: No.

MEMBER POWERS: So I can have a good model of a fire and no model of the Hemyc and predict how the Hemyc behaves?

MR. FRUMKIN: Well, one method that I think is the way, at least, the SDP does it is it assumes that whatever fire exposures ASTM E-119 and then you get a duration of however long the Hemyc would survive in that extreme exposure and conservatively that's the duration and then that value of, let's say, 24 minutes under the extreme duration is plugged into the probability of nonsuppression which even a 24 minute, getting 24 minutes of protection, can be quite a large increase.

MEMBER POWERS: Well, it's the 24 minutes that I don't understand.

MR. FRUMKIN: The 24 minutes is based on the ASTM E-119.

MEMBER POWERS: It's based on one observation and one test.

MR. FRUMKIN: Yes.

MEMBER POWERS: Now the uncertainty in one observation in one test is reasonably large like 100 percent. That means you're somewhere between zero and 48 minutes.

MR. GALUCHI: The results showed that the -- I did the analysis for the test results. I assumed the shortest failure time for any of the Hemyc in the tests I think was on the order of 15 minutes. I did the analysis assuming a distribution -- There were multiple failure times recorded during the test. Some failed at 15. Some failed at 25. Some failed at 40. It was one test but there were multiple layouts of the Hemyc. So by putting a distribution on the failure times and then you assume that as soon as that failure time is reached, you give no credit whatsoever to any type of -- it's instant cable failure. You can do the analysis based on that.

MEMBER POWERS: But you used simple distributions.

MR. GALUCHI: Correct.

MEMBER POWERS: With no reason to think that those distributions are in there. Use a Levy flight distribution and see what happens to you.

MR. GALUCHI: I used multiple different distributions.

MEMBER POWERS: -- and see what happens to your analysis.

MR. SALLY: I hear what you're saying, Dana. In the Office of Research, we actually were thinking about doing what you -- We actually had proposed to do what you suggested here. Before we did the first test, before we ran the first test, we all looked at it and this is heat transfer 101. Okay. This is Foyer's Law. You got this noncombustible material here and you're going to have a heat flux on one side. We're going to transfer heat through it. What's going to be our delta T across the barrier? You know, Foyer's Law, and that's where we were going and we had actually planned that we could write a nice little 98 cent computer model to do that.

What screwed us up on this, Dana, is the joint failure.

MEMBER POWERS: Yes.

MR. SALLY: We did not find it. The material never lasted long enough for the heat to transfer nice and uniformly through the material to heat up the Ox out of the raceway like we measure it. We always had a joint before it.

To try to help the Ray here a little bit is each test we probably had eight or ten different assemblies and the failure times range from roughly 15 minutes was the worst case. We had a junction box where if you could picture it a baseball. We had installed the Hemyc around there and sewed it just like you have the seams on a baseball. The junction box was totally sown. There was no banding, no tie wires, no bolt-throughs. That's the earliest failure we could find at 15 minutes.

MEMBER ARMIJO: Did this stuff just peel off?

MR. SALLY: There's a picture I can send you of this glowing cherry red junction box in the test.

MEMBER ARMIJO: I guess my question was is the fire bypassing the insulator by virtue of --

MR. SALLY: Once you open the joints up, the numbers Dan gave you are off a little bit. But the E-1 19 at the end of -- in ten minutes you're roughly at 500 degree F. In one hour you're out 1700 degrees F. So I don't think it's overkill but it's warm. It's fairly robust and hot. But we did see the failure. Once you expose the raceway and you have a metallic item receiving a heat flux, it's over that quick. So the joints were always the limiting mode.

So, Dana, we couldn't actually in good faith do that because the correct model we need is when do your joints fail.

MEMBER POWERS: Yes.

MR. SALLY: And now we have to look at the mechanics and we surely didn't have enough. As a matter of fact, even after we completed our stuff, industry did two things. (1) They said we cheated because the original stuff was made of a material called Siltem. The last hurricane that came up here wiped out the Siltem factory two or three years ago up here. Outside of Delaware is where it was made.

The vendors said that's okay. Refersil was the exact same stuff. It was an acceptable change from the word go. So we had to buy brand new stuff which was Refersil which is where we got our results. So the first thing industry did was went back into the milled stock that had been laying around for 10 or 15 years in the plant and they reran our tests using Siltem and they got the same results.

The other thing was that we tested the simplest configurations and when you run the test, you set up a nice assembly that you can control and go into the test lab and test it. When you go in the plant, it's a different world. You have a lot of hangers, obstructions and everything becomes one-of-a-kind. So they tested some of the one-of-the-kinds and again, it's basic heat transfer. The more mass you stick in here the greater the heat sump you have the capacity to heat up it makes all the difference in the world. Your smaller conduits fail quicker than your larger ones because of mass unless the joints are open which is off to the races.

So, Dana, I hope -- We went out with good intentions starting it to come up with a model and it didn't work out that way.

MEMBER POWERS: I don't think it's reliable. I mean, it just becomes a mystery to me how you used probabilistics to get you out of the trouble here. I just don't know how they're going to do it within NFPA 805 except in making plausible but largely unsubstantiated assumptions.

MR. FRUMKIN: I think 6850 as a method for dealing with an hour rated barrier, looking at Ray Galuchi, but I believe it has a method for looking at an hour rated barrier which may only have one test to support it and that's been the standard there and fire protection is you can have ten failures. But then if you can make it pass, then it's success and I guess from a probabilistic standpoint that needs some scrutiny.

MEMBER STETKAR: You know what they really do, Dan, is you're talking about a distribution on nonsuppression time. So kind of regardless of what evidence they have from the material, if you're going to use the probabilistic argument as you have the uncertainties on the nonsuppression time fixed which can have a lot of judgment in it, you still might be able to convince yourself that the particular application satisfies some sort of risk criterion. You know, if they send a five percent probability that the stuff lasts two minutes, if that's important to the results, then obviously you need to look more carefully.

Another -- What you're saying is you wouldn't have much confidence in actual measured performance as giving you a reasonably well-defined probability distribution for that time and I'd certainly agree with that. But in a particular application if you stretch that to really account for what your uncertainty might be and can still show that you meet whatever acceptance criteria, they might be able to do that.

MR. SALLY: There is one other thing we're working on and I'll underline the working on, one of the other projects we're doing in fire modeling, the fourth part of it, is the fire model users guide and we expect people to ask this very question that you're asking today when they're out there trying to implement NFPA 805 applications. If I look at one of the tests and I could justify like generic letter 8610 tells me that my construction is very similar in the field to this one that's tested and I knew that the first failure occurred at, let's say, 30 minutes, so by the way that we've done business since generic letter 8610 which is how it tells you to compare the as-built to the tested, I could say I have a 30 minute fire barrier, okay, based on how thick the material is, how good the raceway is, the mass and the raceway, etc.

The next challenge becomes if I fire model that area, what does 30 minutes mean? Now that 30 minutes is all predicted on the fact that I ran a standard ASTM E-119 test and this is the time/temperature curve. What we did in the '60s when we took the area under the curve and we integrated the area and we come up with some crazy units of energy/time units of the area under the curve and you said okay if I took the fire loading would I be bounded by that curve? And that's 1960's logic. It's quite rudimentary because the fire don't always burn that way, etc. The fuel loads can spread around and they can be directly under the raceway versus somewhere else in the fire area.

One of the challenges, Dana, that we're trying to work out is if I have that 30 minute and I know it came from the E-119 curve, what does that mean in fire modeling space? For a given fire model, say, I ran a very conservative fire model for that area. How do I equate the two? That's something that we have the NIST guys and EPRI and us are working on is what's a good, reasonable logic on how to equate the two? Hopefully, that's going to help the plants out in 805 space. So we're looking at saying give me the maximum what the fire model is going to give you, kind of if you will, worst case fire given these combustibles and this is a realistic bounding of the test. That's what we're trying to do with that in the fire modeling space.

George wants to help me here.

MEMBER APOSTOLAKIS: No. I'm looking at my colleague here.

MEMBER MAYNARD: Do we have any more questions? We're about at our time here.

(No response.)

MEMBER MAYNARD: Alex, we appreciate your presentation and it looks like we'll be getting together again later on some of these issues. We'll get an update and some of them we get to review and provide comments on. Thanks very much.

CHAIRMAN SHACK: Right on time.

MEMBER MAYNARD: Back to you, Mr. Chairman.

CHAIRMAN SHACK: Time for a break until 5:00 p.m. Off the record.

(Whereupon, at 4:43 p.m., the above-entitled matter recessed and reconvened at 5:00 p.m. the same day.)

CERTIFICATE

This is to certify that the attached proceedings before the United States Nuclear Regulatory Commission in the matter of:

Name of Proceeding: Advisory Committee on Reactor Safeguards

Docket Number: n/a

Location: Rockville, MD

were held as herein appears, and that this is the original transcript thereof for the file of the United States Nuclear Regulatory Commission taken by me and, thereafter reduced to typewriting by me or under the direction of the court reporting company, and that the transcript is a true and accurate record of the foregoing proceedings.

Charles Morrison

Charles Morrison
Official Reporter
Neal R. Gross & Co., Inc.

Fire Protection Program Briefing for ACRS

Office of Nuclear Reactor Regulation
Division of Risk Assessment
Fire Protection Branch

September 6, 2007

1

Briefing Objective –

Alex Klein – AFPB Acting Branch Chief

- For the Office of Nuclear Reactor Regulation (NRR) Fire Protection Branch (AFPB) to provide ACRS a status update on key fire protection program activities
- Additional near-term ACRS interactions are also anticipated

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Topics

- 10 CFR 50.48(c): NFPA 805 Transition
  - Paul Lain – Senior Fire Protection Engineer
- Multiple Spurious Actuations (MSAs)
  - Daniel Frumkin – Acting AFPB Team Leader
- Post-Fire Operator Manual Actions
  - Peter Barbadoro – Fire Protection Engineer
- Hemyc and MT Generic Letter
  - Daniel Frumkin – Acting AFPB Team Leader

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10 CFR 50.48(c): NFPA 805 Transition – Paul Lain

- Status
- Lessons Learned
- Transition
- Guidance

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NFPA 805 – Status

- Letters of Intent for 42 Units at 27 Sites
- 37 Units at 23 Sites are Actively Transitioning
- 36 Month Discretion Period to Transition
- Nine Pilot Observation Visits
- Frequently Asked Question (FAQ) Process
- 14 Public Meetings w/ NEI 805 Task Force
- Non-Pilot Update at the NEI FP Info Forum

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NFPA 805 – Lessons Learned

- PRA Compartmentation
- Ignition Frequency Database
  - Counting Electronic Cabinets
  - Counting HEAF Sources
- Configuration Control
- NEI 04-02, Appendix B Table Details
- LP/SD Qualitative Review
- Carrying Forward Existing Licensing Bases

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NFPA 805 – Transition

- Pilots
  - Two more Observation Visits
  - Staff Review their Fire PRAs of Pilots
  - LAR Submittal expected next May/June '08
- Non-Pilots
  - Complete their Fire PRAs
  - Conduct Fire PRA Peer Reviews
  - LAR Submittal Start in Nov/Dec '08

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NFPA 805 - Guidance

- NUREG/CR-6850
- NUREG-1824
- FAQ RIS
- NEI Fire PRA Peer Review Guidance
- ANS Fire PRA Standard
- NEI 04-02 Revision Scheduled for Dec/Jan
- RG 1.205 Revision
- Standard Review Plan
- Post-Transition Inspection Procedures

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Multiple Spurious Actuations (MSAs) – Dan Frumkin

- Background
- Highlights of NEI's Multiple Spurious Actuation Resolution Methodology
- NRC Staff's Views of the NEI Methodology
- Next Steps

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MSAs - Background

- NRC Staff proposed Generic Letter (GL) 2006-XX requesting licensees to confirm compliance in light of the relatively high probability of multiple spurious actuations
- Commission disapproved issuing proposed GL in SECY/SRM-06-0196, "Issuance of Generic Letter 2006-xx, '*Post-Fire Safe-Shutdown Circuits Analysis* Spurious Actuations'" December 1, 2006
- NRC staff continues to use the SECY/SRM-06-0196 for direction
- NRC staff met with Industry and received Industry's methodology of a method in 02/2007
- Industry presented their detailed methodology to address multiple spurious actuation on September 6, 2007

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MSAs - Highlights of NEI's Multiple Spurious Actuation Resolution Methodology

- Uses insights regarding MSA's of concern based on systems interactions developed by owners groups
- The NEI resolution methodology uses risk information when available but an expert panel is used for completeness
- NEI proposes that the methodology applies to III.G.1 and III.G.2
- The technical aspects of the framework would be applicable to all non-805 plants

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MSAs - NRC Staff's Views of the NEI Methodology

- Proposed methodology includes consideration of risk in determining compliance outside of 10 CFR 50.48(c)
- Cumulative and synergistic effects should be considered, which may not be effectively considered by an expert panel
- If PRA methods or tools are used, these methods or tools should be of adequate detail and quality
- Need to consider MSAs in III.G.3 (III.L) areas

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MSAs - Next Steps

- NRC staff will continue to engage NEI to address MSA's
- Commission directed in SECY/SRM-06-0196, that the NRC staff should continue to encourage licensees to transition to 10 CFR 50.48(c), NFPA 805, the agency's risk-informed, performance-based fire protection rule.

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Post-Fire Operator Manual Actions (OMAs) – Peter Barbadoro

- SECY/SRM-06-0010
- Status of Issuance of NUREG-1852
- Final Remarks

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OMAs - SECY/SRM-06-0010 –

"Withdraw Proposed Rulemaking - Fire Protection Program Post-Fire Operator Manual Actions"

- Proposed rule has been withdrawn
- Standard Review Plan (SRP) Section 9.5.1, "Fire Protection Program", and Inspection Procedure (IP) 71111.05T, "Fire Protection [Triennial]," have been updated
- Regulatory Issue Summary 2006-10, "Regulatory Expectations with Appendix R Paragraph III.G.2 Operator Manual Actions," issued June 30, 2006
- Reactor Oversight Process continues to verify compliance with regulations and commitments

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OMAs - Status of Issuance of NUREG-1852, "Demonstrating the Feasibility and Reliability of Operator Manual Actions in Response to Fire"

- NUREG-1852 addresses the performance of post-fire operator manual actions
- Public comments have been dispositioned
- July 13, 2007 ACRS letter stated that NUREG-1852 should be published as final
- CRGR Meeting August 8, 2007, awaiting final CRGR position.
- NUREG-1852 will be issued following acceptable review by CRGR

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OMAs - Final Remarks

- Licensees are expected to bring operator manual actions back into compliance as described in RIS 2006-10
- NRC Staff intends to use NUREG-1852 for future licensing actions or exemptions relating to the use of post-fire operator manual actions

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Hemyc and MT Generic Letter - Daniel Frumkin

- GL 2006-03, "Potentially Nonconforming Hemyc and MT Fire Barrier Configurations" Issued April 10, 2006
- All licensees responded in accordance with the information request
- 16 licensees reported Hemyc or MT
  - 10 licensees resolving Hemyc or MT issues through NFPA 805
  - 1 licensee removed Hemyc
  - 3 licensees requested exemptions
  - 2 licensees use as radiant energy shields

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GI-156.6.1

PIPE BREAK EFFECTS ON SYSTEMS AND COMPONENTS INSIDE CONTAINMENT

Harold VanderMolen RES/DRASP/OEGIB

Abdul Sheikh RES/DFERR/ERA/MS

Outline

- Issue Description
- Historical Background
- Idaho Screening Analysis
- BWR investigation
- PWR investigation
- Conclusion – Issue can be closed out with no new requirements

Safety Question

- SRP contains specific criteria for postulated pipe break locations, pipe whip restraints, and I&C separation criteria
- Many plants were designed & built before the first SRP was issued in 1975
- Are there possible interactions due to pipe whip and/or jet impingement in these older plants?

Affected plants

- 51 units originally within the scope of this generic issue
- 10 units permanently shut down
- 18 BWRs still operating
- 23 PWRs still operating

History of GI-156.6.1

Begin Systematic Evaluation Program (SEP)	1977
Integrated Safety Assessment Program (ISAP)	1984
SEP program terminated	1990
Remaining open SEP issues transferred to GI program – became GI-156 group	1991
GI-156.6.1 given "Medium" priority	1994
"Enhanced" screening assessment of GI-156.6.1	1999

Idaho screening assessment

- Reviewed FSARs
- Reviewed Integrated Plant Safety Assessment Report
- Reviewed design changes made after SRP issuance
- Performed five site visits
- Developed first-level list of "concerns"
- Narrowed list down to second-level list based on site visits
- Developed initial probabilistic screening to further reduce the list

Idaho analysis results

BWRs

- BWR Mark I all similar
- Design tends to encourage 180° separation
- Water level reference columns & pressure sensors are outside of primary containment
- Dominant sequences involve drywell puncture

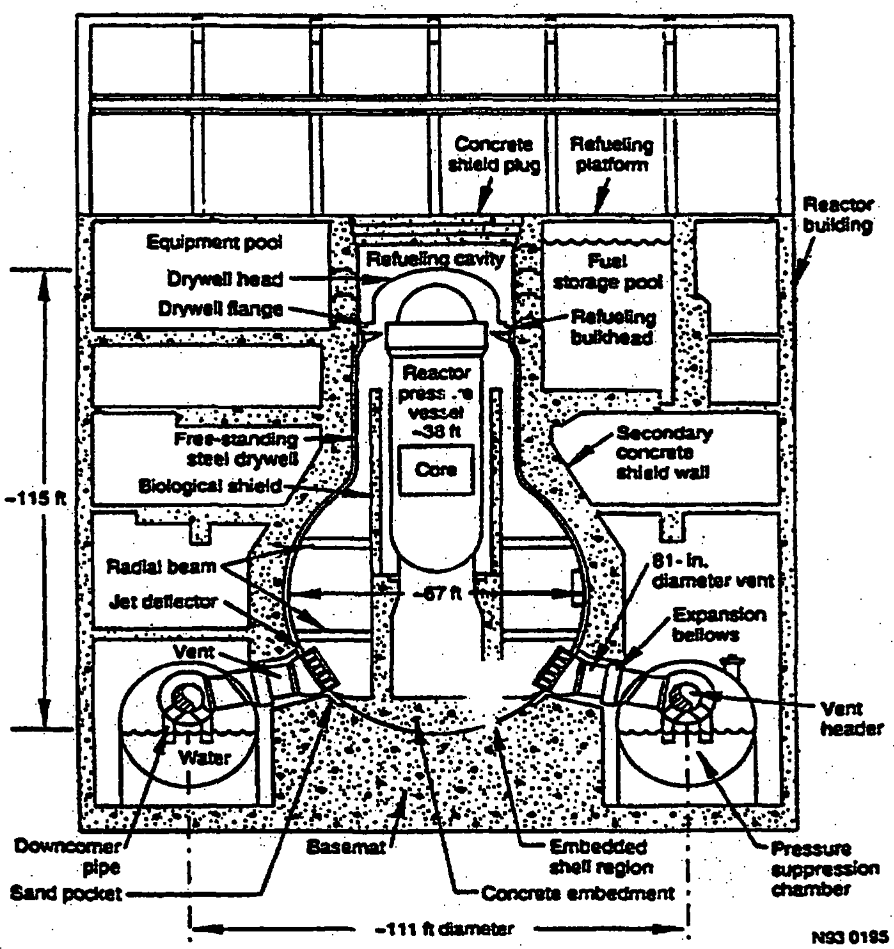
PWRs

- PWR containments vary widely
- Compartmentalization and seismic restraints reduce primary system interactions
- Dominant sequences involve secondary system breaks near electrical penetrations

BWR Scenarios

- Whipping pipe impacts and penetrates steel drywell wall
- Steam discharges into gap between drywell wall and concrete secondary shield wall
- Steam exits gap area, enters area surrounding torus
- Hostile environment disables LPCI, core spray
- Result could be severe core damage with failure of primary containment

BWR layout

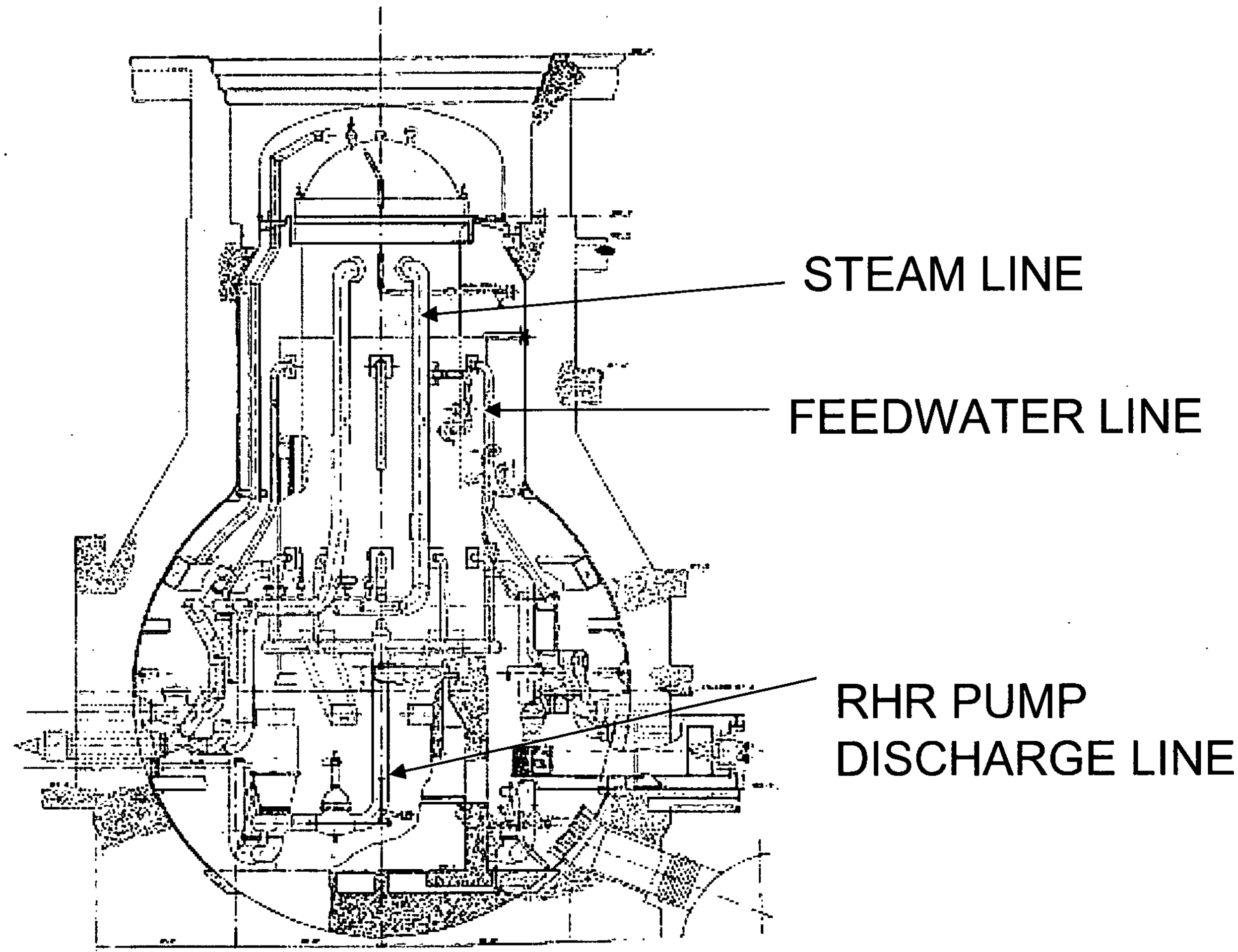


Concrete shield plug
Refueling platform
Reactor building
Equipment pool
Drywell head
Drywell flange
Refueling cavity
Fuel storage pool
Refueling bulkhead
Reactor pressure vessel ~38 ft
Core
Free-standing steel drywell
Biological shield
Secondary concrete shield wall
~115 ft
Radial beam
Jet deflector
~67 ft
81-in. diameter vent
Expansion bellows
Vent
Vent header
Water
Downcomer pipe
Sand pocket
Basemat
Embedded shell region
Concrete embedment
Pressure suppression chamber
~111 ft diameter
N93 0185

Pipe Impact on Steel Drywell

- Postulated Pipe Breaks Inside Drywell
  - Main steam pipe at reactor nozzle
  - Feedwater pipe at reactor nozzle
  - RCS pumps discharge lines at reactor nozzle
- Structural Evaluation
  - ANSYS computer code
  - Lower and upper bound values of blowdown force
  - Minimum thickness of drywell (0.64 inch)
  - Maximum gap between drywell steel and concrete shield (3.125 inch). Normal as-built gap 2.0 inch

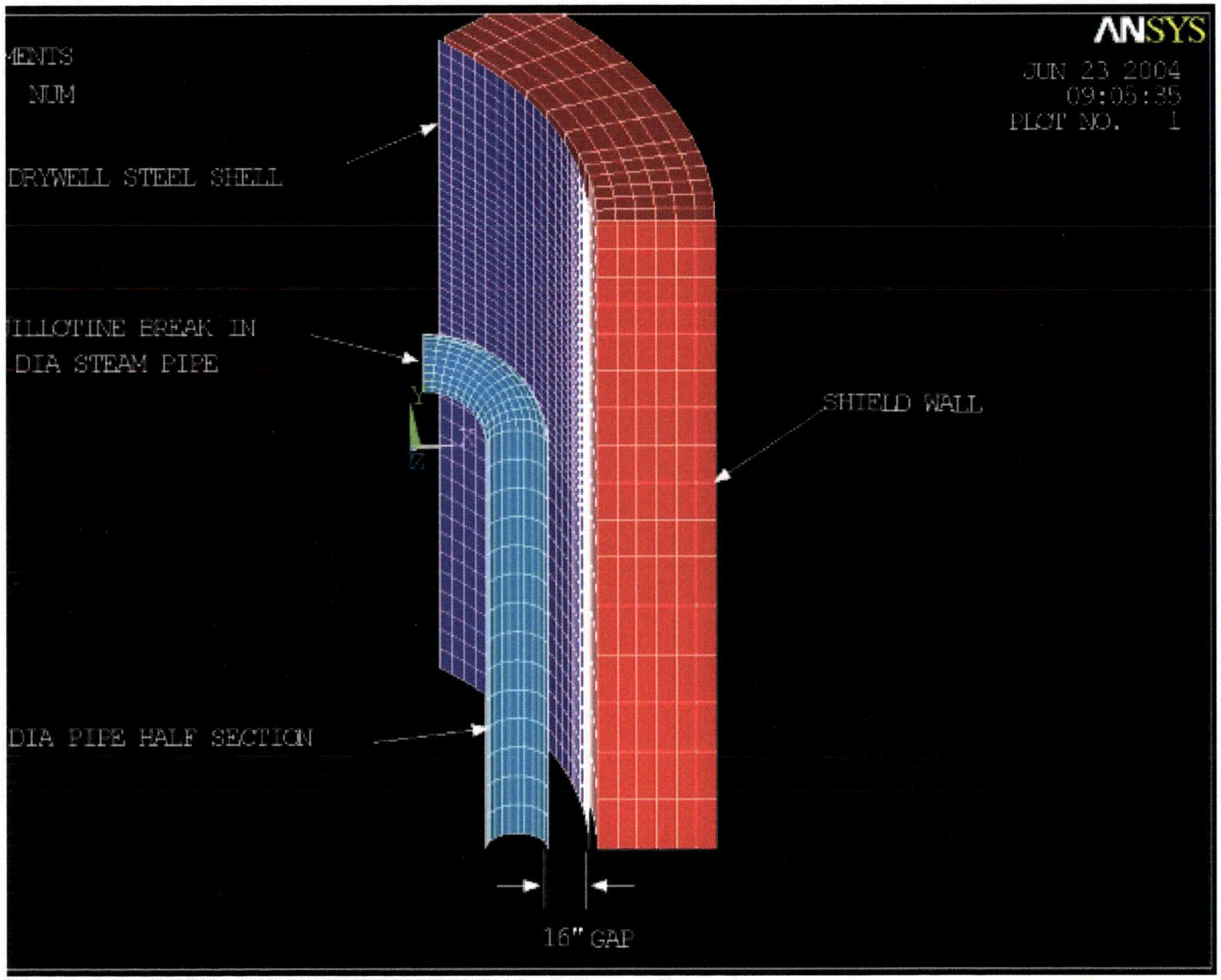
BWR Mark I Piping



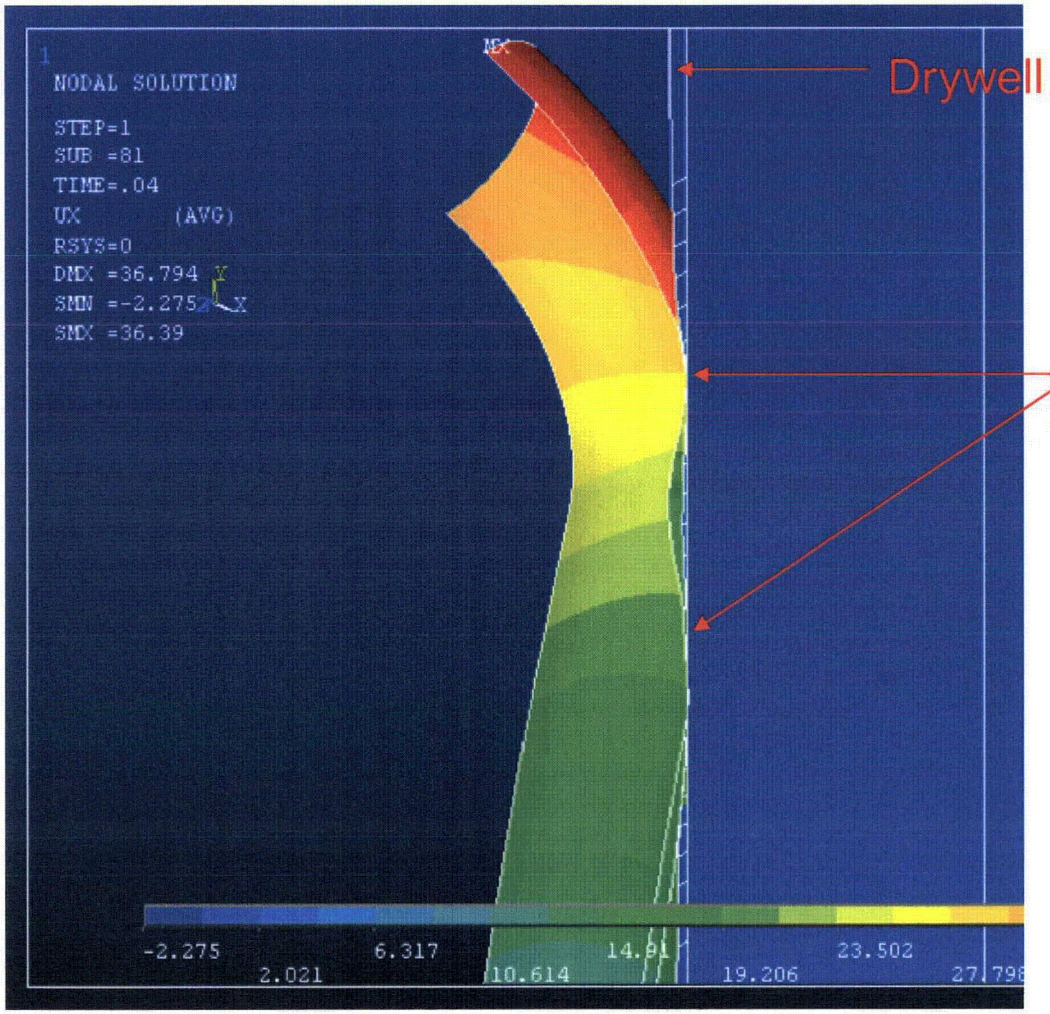
Main Steam Line Break

- Pipe
  - Diameter: 24 inch
  - Wall Thickness: 1.30 inch
  - Minimum ultimate strain of pipe material: 22%
  - Gap between drywell and steam line: 16 inch
  - Operating pressure: 1050 psi
- Double ended guillotine break
- Pipe whip force: 0.70 to 1.2 PA
- Maximum drywell strain: 10%
- Drywell will deflect and come into contact with concrete shield
- Drywell will not perforate
- Containment drywell Integrity would not be compromised

Main Steam Line ANSYS Model

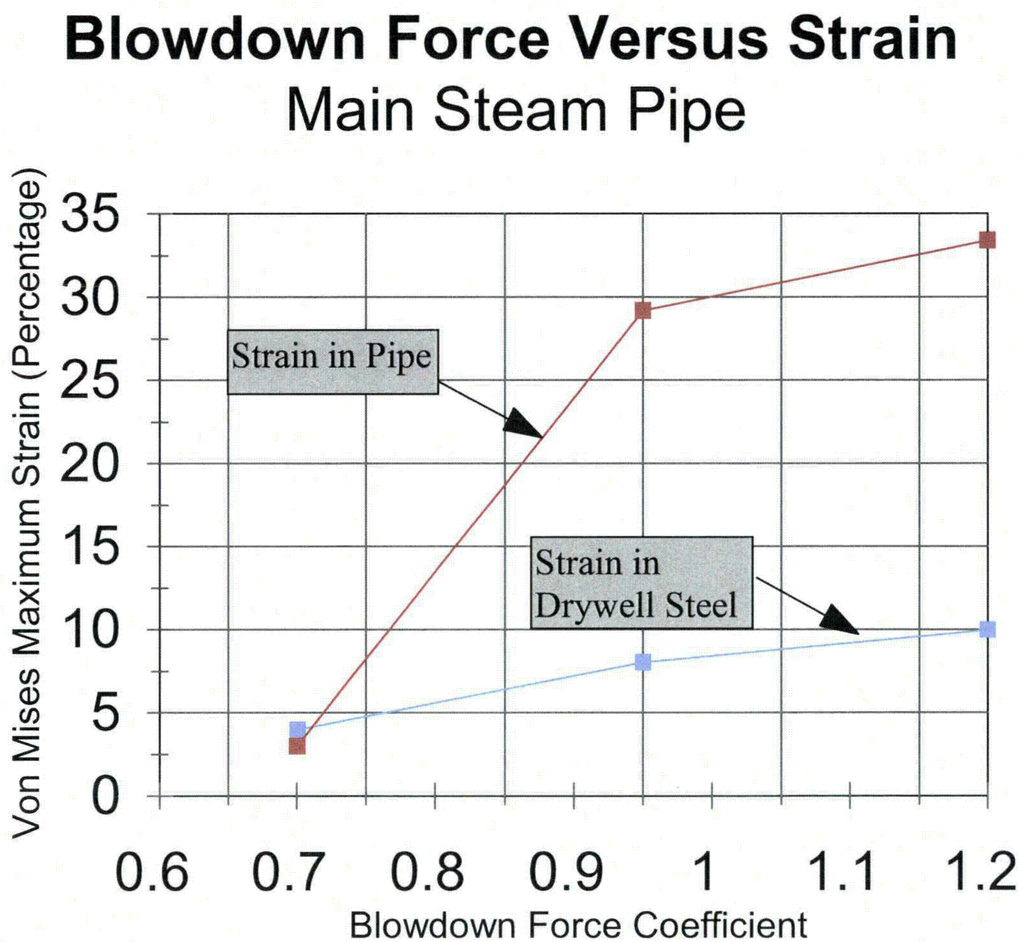


Main Steam Line and Drywell Deflected Shape



Drywell in touch with concrete and pipe

Steam Line and Drywell Strains



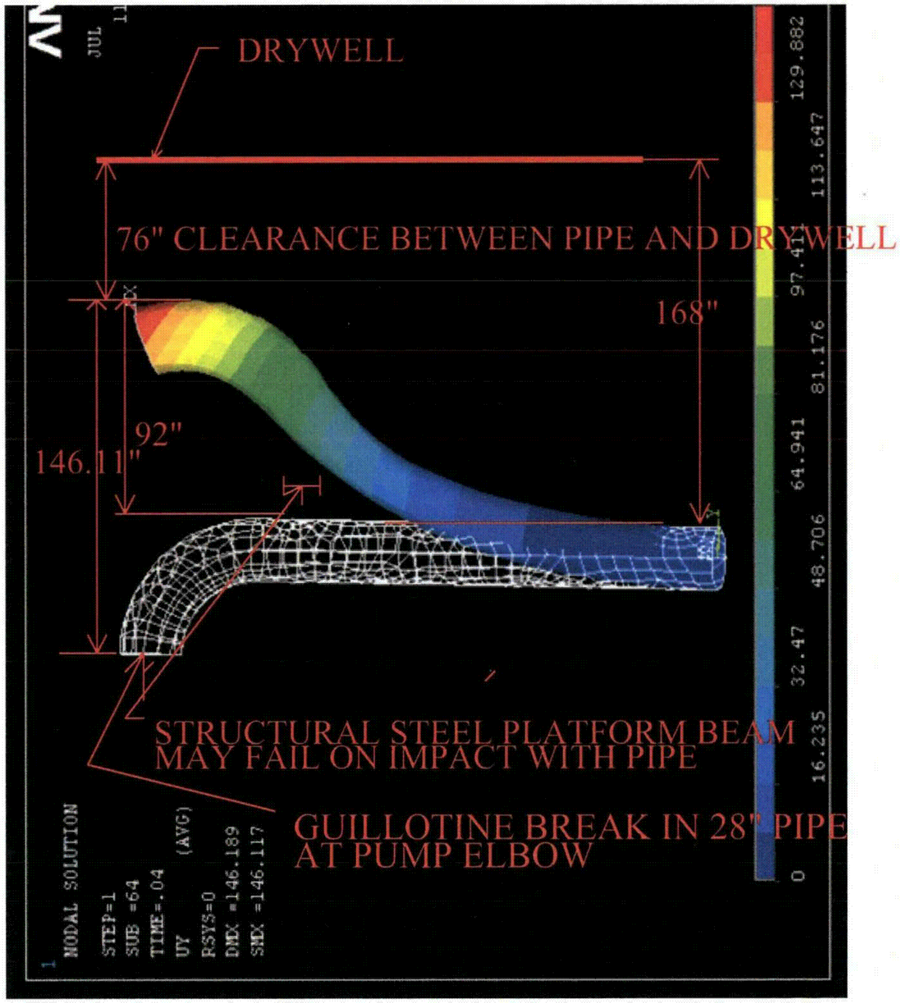
Feedwater Line Break

- Pipe
  - Diameter: 10.75 inch
  - Wall Thickness: 0.625 inch
  - Minimum ultimate strain of pipe material: 22%
  - Gap between drywell and steam line: 24 inch
  - Operating pressure: 1050 psi
- Double ended guillotine break
- Pipe whip force: 1.3 - 2.1PA
- Pipe would deflect 6-18 inches
- Plastic hinge formed
- Pipe would not impact drywell located 24 inch away before failure
- Pipe may impact drywell after failure
- Drywell would not perforate
- Containment drywell Integrity would not be compromised

RCS Pipe Break

- Pipe
  - Diameter: 28.00 inch
  - Wall Thickness: 1.5 inch
  - Minimum ultimate strain of pipe material: 40%
  - Gap between drywell and steam line: 168 inch
  - Operating pressure: 1050 psi
- Double ended guillotine break
- Pipe whip force: 1.3 - 2.2 PA
- Pipe would deflect 62-146 inches
- Pipe impact and damage structural steel beams or PCS piping
- Plastic hinge formed
- Pipe would not impact drywell located 168 inch away before failure
- Pipe may impact drywell after failure
- Drywell would not perforate
- Containment drywell Integrity would not be compromised

RCS Pipe Deflected Shape



Conclusion - BWRs

- Containment penetration scenario does not appear to be credible
- Therefore, there is insufficient basis to justify any further regulatory action

PWR scenarios

- Initiated by pipe break within containment
- Pipe whip or fluid jet disables a system needed to mitigate the break

PWR scenarios (continued)

- Pipes are equipped with seismic restraints, limiting pipe whip
- PWR containments are compartmentalized. A break in one primary loop cannot cause failure of equipment in another loop or in the pressurizer
- Concluded that primary system break very unlikely to initiate this scenario

PWR Scenarios (continued)

- Secondary system piping not necessarily separated by walls
- Secondary system piping will have seismic restraints, but fluid jets could impact I&C cables
- I&C cables will be dispersed except near penetrations
- Biggest vulnerability likely to be a secondary pipe break near cable penetrations

PWR Scenarios (continued)

- Safety systems will still actuate on high containment pressure
- However, loss of I&C cables may interfere with long-term recovery

PWR investigation strategy

Every PWR unique

- Examined FSARs
- Examined plant diagrams
- NRR assisted – resident inspectors & licensee personnel

Looked for:

- >90° separation
- Intervening walls
- Intervening floors
- Large difference in elevation

PWR investigation results

- Nine units have two electrical penetration areas separated by 90° or more
- 10 units have single electrical penetration area, but
  - have concrete floors or walls separating electrical penetrations from piping
  - Have significant distance between electrical penetrations and piping
  - Have some combination of the above

[continued]

PWR Investigation Results (continued)

- Two units had an analysis of piping stresses which concluded that the piping, if overstressed, would break at a location which would not spray water on electrical penetration area
- Two units had the electrical penetration area partly shielded by a concrete floor. A steam or feedwater pipe could disable one channel of temperature instrumentation and one bank of pressurizer heaters, but not both channels.

Conclusion – PWRs

- No plant found to have a significant vulnerability
- Therefore, there is insufficient basis to justify any further regulatory action

Final Recommendation

- Generic Issue 156.6.1 be closed out
- ACRS concur in letter to EDO

Standard Review Plan (SRP) Sections 19.0 and 19.2

Division of Safety Systems and Risk Assessment
Office of New Reactors

September 2007

Outline

- Background
- Applicable regulations
- Timeline
- RG and SRP renumbering
- Uses of the PRA
- PRA scope, level of detail, and technical adequacy
- PRA documentation
- Revision of SRP Section 19.2
- Clarifications

Background

- September 2006 – DG-1145 issued for comment
- October 2006 – Office of New Reactors established
- October 31, 2006 – Staff issued SECY-06-0220 (deleted the requirement to submit the PRA)
- December 12, 2006 – ACRS letter on DG-1145
- February 2007 – Two PRA branches established in NRO
- April 11, 2007 – Commission issued an SRM on SECY-06-0220 (agreed with the staff)
- June 22, 2007 – RG 1.206, SRP Section 19.0, and SRP Section 19.2 issued
- August 28, 2007 – Revised Part 52 issued (along with conforming changes in other regulations)

Applicable Regulations (1 of 3)

- Design Certifications:
  - 10 CFR 52.47(a)(27) - The FSAR must contain "…a description of the design-specific probabilistic risk assessment (PRA) and its results."
- Combined Licenses:
  - 10 CFR 52.79(a)(46) - The FSAR must contain "…a description of the plant-specific probabilistic risk assessment (PRA) and its results."

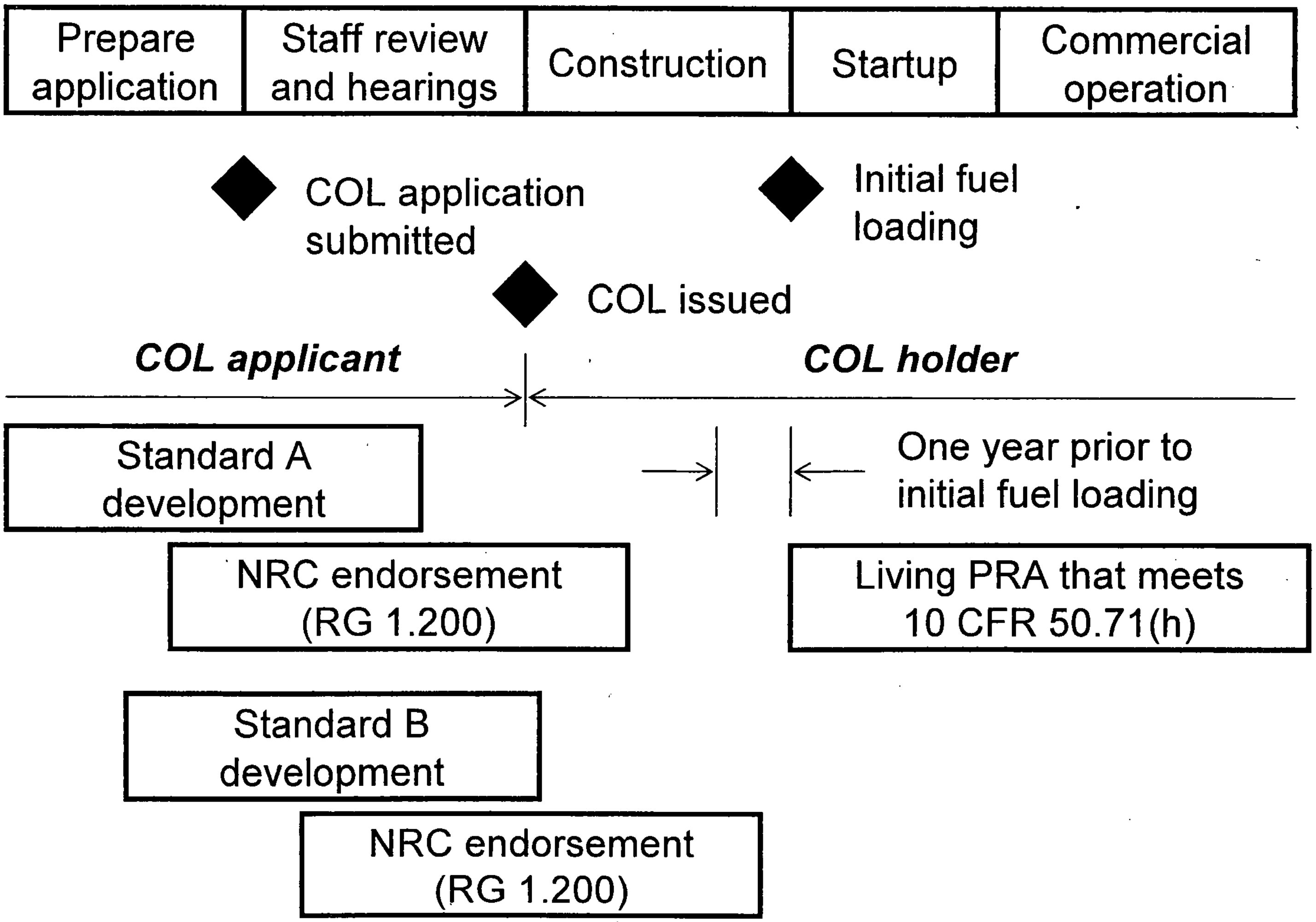
Applicable Regulations (2 of 3)

- If the COL application references a standard design <u>approval</u>, then:
  - 10 CFR 52.79(c)(1) - The plant-specific PRA information must use the PRA information for the design approval and must be updated to account for site-specific design information and any design changes or departures.
- If the COL application references a standard design <u>certification</u>, then:
  - 10 CFR 52.79(d)(1) - The plant-specific PRA information must use the PRA information for the design certification and must be updated to account for site-specific design information and any design changes or departures.
- If the COL application references the use of one or more <u>manufactured nuclear power reactors</u> licensed under subpart F of 10 CFR Part 52, then:
  - 10 CFR 52.79(e)(1) - The plant-specific PRA information must use the PRA information for the manufactured reactor and must be updated to account for site-specific design information and any design changes or departures.

Applicable Regulations (3 of 3)

- For COL holders: PRA maintenance and upgrading
  - 10 CFR 50.71(h)(1) - No later than the scheduled date for initial loading of fuel, each holder of a combined license under subpart C of 10 CFR part 52 shall develop a level 1 and a level 2 probabilistic risk assessment (PRA). The PRA must cover those initiating events and modes for which NRC-endorsed consensus standards on PRA exist one year prior to the scheduled date for initial loading of fuel.
  - 10 CFR 50.71(h)(2) - Each holder of a combined license shall maintain and upgrade the PRA required by paragraph (h)(1) of this section. The upgraded PRA must cover initiating events and modes of operation contained in NRC-endorsed consensus standards on PRA in effect one year prior to each required upgrade. The PRA must be upgraded every four years until the permanent cessation of operations under § 52.110(a).
  - 10 CFR 50.71(h)(3) - Each holder of a combined license shall, no later than the date on which the licensee submits an application for a renewed license, upgrade the PRA required by (h)(1) to cover all modes and all initiating events.

Timeline



Prepare application
Staff review and hearings
Construction
Startup
Commercial operation
COL application submitted
Initial fuel loading
COL issued
COL applicant
COL holder
Standard A development
One year prior to initial fuel loading
NRC endorsement (RG 1.200)
Living PRA that meets 10 CFR 50.71(h)
Standard B development
NRC endorsement (RG 1.200)

RG and SRP Renumbering

Old SRP	New SRP	RG	Topic
n/a	Section 19.0	RG 1.206 - C.I.19 - C.III.1	Combined License Applications for Nuclear Power Plants (LWR Edition) COL applications that are not based on a DC COL applications that are based on a DC (see Chapter 19 for PRAs)
Chapter 19.1	Section 19.1	RG 1.200	PRA technical adequacy
Chapter 19	Section 19.2	RG 1.174	Risk information used to support permanent plant-specific changes to the licensing basis

PRA Scope for a COL Application

- Level 1 (core-damage) and Level 2 (containment analysis)
- All initiating events
  - Internal initiators (e.g., transients, LOCAs)
  - External initiators (e.g., seismic, internal fires)
- All operating modes
  - Full-power
  - Low-power and shutdown
- A lack of NRC-endorsed industry consensus standards does not reduce this scope

PRA Level of Detail

- Must reflect the as-to-be-built and as-to-be-operated plant
  - Need to review the DC PRA, and revise as necessary (e.g., site-specific service water system design)
  - Use of bounding analyses is acceptable under certain conditions
    - Identify vulnerabilities, design and operational requirements, ITAACs, COL Action Items
    - Do not mask or distort risk-significant information or risk insights

PRA Technical Adequacy

- RG 1.200 provides one acceptable approach to demonstrating acceptable technical adequacy
- NRC-endorsed industry consensus standards require peer reviews
- The ASME PRA Standard states that users may need to add or revise requirements in the Standard to address advanced LWRs (novel or passive features, digital I&C, etc.)
- Meeting NRC-endorsed industry consensus standards should help expedite the staff's review

PRA Documentation

- Information to be included in the FSAR has been identified in RG 1.206, Section C.I.19, Appendix A
  - COLs based on a DC may include information by reference (see RG 1.206, Section C.III.1, Chapter 19 for guidance)
- Applicants should maintain archival information per RG 1.200
- NRC staff may seek clarifying information through the RAI process or through audits (documented in a publicly available audit report that can be referenced in the staff's SER)

Format and Content

- RG 1.206, Section C.I.19, Appendix A (format and content guidance) provides one acceptable definition of the phrase "description of the PRA and its results."

Description of the PRA

- PRA methodology
- List of initiating events
- Success criteria (what they are, how they were determined including T/H codes used)
- Accident sequences (event tree plots may be helpful)
- List of plant systems and functions, including dependency matrix
- Identify the source of all numerical data used
- PRA software platform
- PRA truncation limit

PRA Results

- Risk metrics (CDF, LRF, CCFP)
- Description of significant sequences and their mean frequencies
- Significant initiating events and their percent contribution to the overall risk metrics
- Significant functions, SSCs, operator actions and their FV importance and RAW values
- PRA assumptions and PRA-based insights
- Results from sensitivity and uncertainty analyses

Revision of SRP Section 19.2

- Updates made in accordance with NRR Office Instruction LIC-200, Rev. 1
- Added references to RG 1.200 and SRP Section 19.1 concerning PRA technical adequacy
- Some rewording as directed by OGC
- Some changes to improve clarity, correct errors, etc.

Clarifications (1 of 4)

- The staff has held three public meetings to discuss PRA information to support DC and COL applications
  - Well-attended by prospective DC and COL applicants
- The meetings help to identify a list of "frequently asked questions"
  - The staff has developed answers to most of the FAQs
  - The staff plans to issue Staff Interim Guidance (ISG) on these clarifications

Clarifications (2 of 4)

- Format is optional, but all content should be provided
- Seismic and fire risk evaluations may use the methods used in the DC PRA; however, once consensus standards are endorsed by the staff, applicants should follow these standards
- 10 CFR 50, Appendix B does not apply to DC or COL PRAs
- Chapter 19 PRA information is not subject to the Tier 2 change process
- Generally, Capability Category 1 is adequate for a DC or COL PRA

Clarifications (3 of 4)

- With respect to 10 CFR 50.71(h) and the use of NRC-endorsed standards that exist one year prior to fuel load, applicants may petition to change the rule or seek an exemption from the rule
- Definition of LRF
  - NRC has not issued a formal definition
  - Applicants may use the definition used to develop the DC PRAs
  - Staff is considering ways to reconcile the use of LRF for Part 52 licensing and the use of LERF for risk-informed LARs per RG 1.174
- PRA maintenance starts at the time of application; PRA upgrade starts at the time of initial fuel load
- COL holders are expected to maintain the entire scope of the PRA performed to support the COL application

Clarifications (4 of 4)

- Summary PRA quantitative results should be provided in Chapter 19 of the FSAR
- COL applications should be complete; RAIs and audits are used to clarify information
- The COL application must be based on a plant-specific PRA; bounding analyses may be used
- The SAMDA evaluation may be included in either the FSAR or the Environmental Report
- The phrase “regulatory oversight processes” refers to items such as MSPI and SDP (not the staff’s Reactor Oversight Process – ROP)

Path Forward

- Developing Interim Staff Guidance (ISG) to address clarifications
- Collecting risk insights for technical reviewers from DC PRAs
- Performing QA reviews of EPR and U.S. APWR
- Preparing for acceptance reviews
- Preparing for PRA audits

Pilgrim Nuclear Power Station
License Renewal Safety Evaluation Report

Staff Presentation to the ACRS

Perry Buckberg

Project Manager

Office of Nuclear Reactor Regulation

September 6, 2007

Introduction

- Overview
- Section 2: Scoping and Screening Review
- License Renewal Inspections
- Section 3: Aging Management Review Results
- Section 4: Time-Limited Aging Analyses (TLAAs)

Overview

- LRA Submitted by Letter, January 27, 2006
- GE BWR3 - MARK 1 Containment
- 2028 MWth, 690 MWe
- Op License DPR-35 Expires June 8, 2012
- Located in Plymouth, MA

Overview

- SER Issued June 28, 2007
- SSER to be Issued September, 2007
- Open Items (4) Have Been Closed
- Four (4) License Conditions
- 92 RAIs Issued, 329 Audit Questions
- ≈82% Consistent With GALL Report, Revision 1

Review Highlights

- AMP GALL Audit
  - May 22, 2006
- Scoping and Screening Methodology Audit
  - June 6 - June 9, 2006
- AMR GALL Audit
  - June 19, 2006
- AMP/AMR Status Briefing
  - July 17 - 19, 2006
- Regional Inspections
  - September 18 - 22, 2006
  - October 2 - 6, 2006
  - December 6 - 7, 2006

Section 2: Scoping and Screening Review

Section 2.1 - Scoping and Screening Methodology

- On-site Audit - June 6 – June 9, 2006
- Pilgrim included all system components in scope if any components were (a)2 – exceptions stated

Section 2.3

- 4 Additional Components Brought Into Scope

Section 2.2, 2.4, 2.5

- No Omissions

Section 2: Scoping and Screening Review

Section 2.3 – Mechanical Systems

- Open Item 2.3.3.6: Security Diesel
  - LRA Did not Include System Drawings
  - Referred to Regional Inspector to Determine System Components in Scope
  - Staff Considered the 3/9/2007 Inspector Input Adequate to Close the Open Item

Section 2: Scoping and Screening Summary

- The Applicant's Scoping Methodology Meets The Requirements Of 10 CFR Part 54.4

- Scoping And Screening Results, As Amended, Included All SSCs Within The Scope Of License Renewal And Subject To AMR

License Renewal Inspections

Glenn Meyer

Region I

Scoping and Screening

- 54.4(a)(2) - Non-safety SSCs Whose Failure Could Impact Safety SSCs
- Spatial and Structural Interactions
- LRA Drawings and Procedures Reviewed
- Plant Walkdowns Performed

Scoping and Screening Conclusions

- Spatial Interaction - Acceptable
- Structural Interaction – Corrected
- Scoping and Screening Acceptable for License Renewal

Aging Management

- Reviewed 26 AMP Programs
- Reviewed Programs, Evaluations, and Records
  - Program Procedures
  - Operational Experience Information
  - Prior Pilgrim Issues
- Performed Plant Walk Downs
- Interviewed Cognizant Personnel

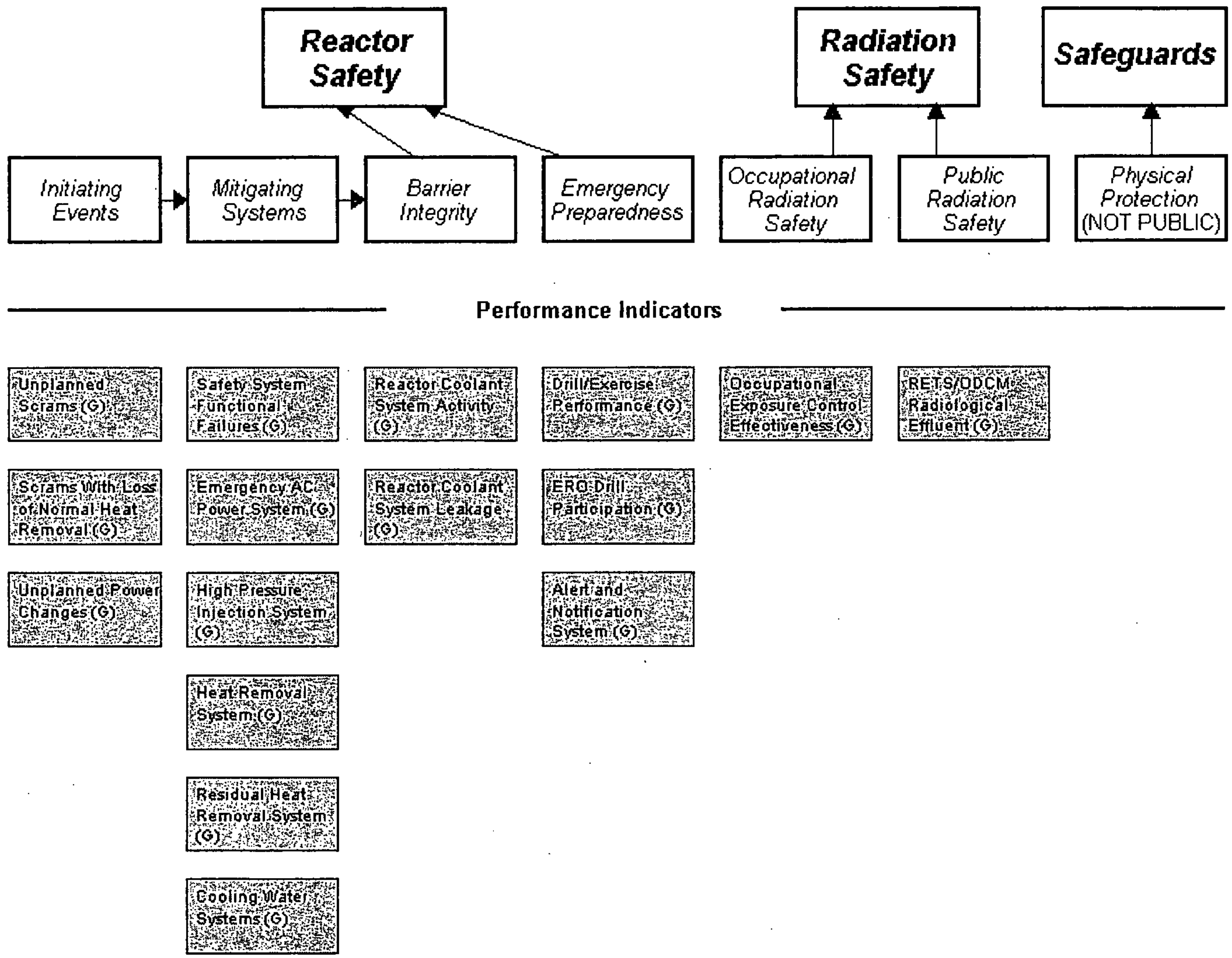
Inspection Conclusions

- Scoping and Aging Management Programs Support Conclusion That Aging Effects will be Managed
- Drywell Shell Monitoring

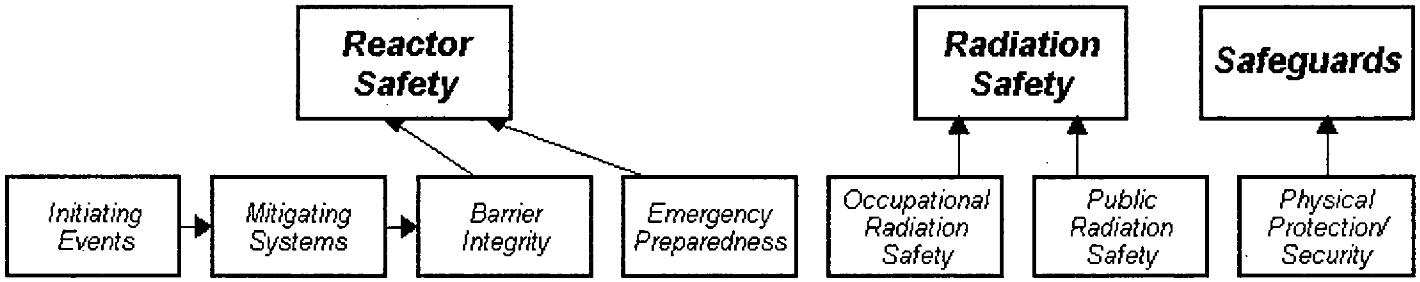
Current Performance

- Licensee Response Column (Column I) of the NRC's Action Matrix – Green PIs and Findings
- No Cross-cutting Issues
- Reactor Oversight Process Baseline Inspections

Performance Indicators



Inspection Findings



Most Significant Inspection Findings

2Q/2007	No findings this quarter	No findings this quarter	No findings this quarter	No findings this quarter	No findings this quarter	No findings this quarter
1Q/2007	No findings this quarter	G	No findings this quarter	No findings this quarter	No findings this quarter	No findings this quarter
4Q/2006	No findings this quarter	G	No findings this quarter	No findings this quarter	No findings this quarter	No findings this quarter
3Q/2006	No findings this quarter	No findings this quarter	No findings this quarter	No findings this quarter	No findings this quarter	No findings this quarter

Miscellaneous findings

Pilgrim Nuclear Power Station
Aging Management Review
Time Limited Aging Analysis
Open Items

Fire Protection Program (B.1.13.1)

- Open Item 3.0.3.2.10:
  - Applicant did not Adequately Address how to Manage the Aging Effects of Inaccessible Seals.
  - Applicant Stated (ACRS) and Documented (June 2007) That There are Actually No Inaccessible Seals at PNPS

Containment Inservice Inspection Program (B.1.16.1)

- Open Item 3.0.3.3.2:
  - Regional Inspection Documented:
    - Inoperative Bellows Rupture Drain Flow Switch
    - Drain Monitoring Inconclusive & Undocumented
    - Water on Torus Room Floor

Containment Inservice Inspection Program (B.1.16.1)

- Open Item 3.0.3.3.2:
  - Replace Switches Now and in 15 years
  - Identified Non-Aggressive Groundwater as Source of Water on Torus Room Floor
    - Tested November 2006 and June 2006
  - Provided Documentation of Drain Monitoring
    - Committed to Obtain Drywell UT Data

Containment Inservice Inspection Program (B.1.16.1)

- Open Item 3.0.3.3.2:
  - Torus Structure
    - Provided Evaluation of Effect on Torus Basemat
    - Commitments to Evaluate Groundwater/Torus Water
    - Commitment to Inspect Condition of Torus Hold Down Bolts and Grout

Section 4.2: Reactor Vessel Neutron Embrittlement

- Six TLAAs Affected by Neutron Fluence
  - Reactor Vessel Fluence
  - Pressure-Temperature Limits
  - Upper Shelf Energy
  - Adjusted Reference Temperature
  - Circumferential Weld Inspection Relief
  - Axial Weld Failure Probability

Section 4.2: Reactor Vessel Neutron Embrittlement

- Open Item 4.2
  - Pilgrim – The First BWR-3 to Use RAMA Methodology to Calculate Neutron Fluence
  - Dosimetry Data was not Available with Which to Benchmark the RAMA Calculated Results
  - Result - Fluence Calculation Not Acceptable Per Reg Guide 1.190

Section 4.2: Reactor Vessel Neutron Embrittlement

- <u>Open Item 4.2</u>
  - Applicant's Back Calculation of Limiting Fluence Values Considered Acceptable by the Staff
  - TLAA Identified Which Established the Limiting Fluence Value
    - Axial Welds @ RV Inner Surface - 3.37 x 10^{18} n/cm2 (E > 1.0 MeV)

Section 4.2: Reactor Vessel Neutron Embrittlement

- Open Item 4.2

  - License Condition 4.2.6: On or before June 8, 2010, the applicant (Entergy) will submit to the NRC correctly benchmarked RV neutron fluence calculations, consistent with RG 1.190, that will confirm that the neutron fluence for the lower intermediate shell axial welds, at the inner surface of the RV, will not reach the limiting value of 3.37×10^{18} n/cm2 (E > 1.0 MeV) by the end of the period of extended operation (54 EFPY).

Section 4.2: Reactor Vessel Neutron Embrittlement

- Open Item 4.2
  - Commitment 47: Submit to the NRC An Action Plan for Benchmarking the Reactor Pressure Vessel Fluence Evaluation.
  - Entergy Plan Submitted August 23, 2007.

Section 4.3: Metal Fatigue

- Reactor Water Environment
  - Removed Exception to Fatigue Monitoring Program regarding Environmentally Assisted Fatigue.
  - Combined FMP and EAF – FMP is Now Consistent with GALL.

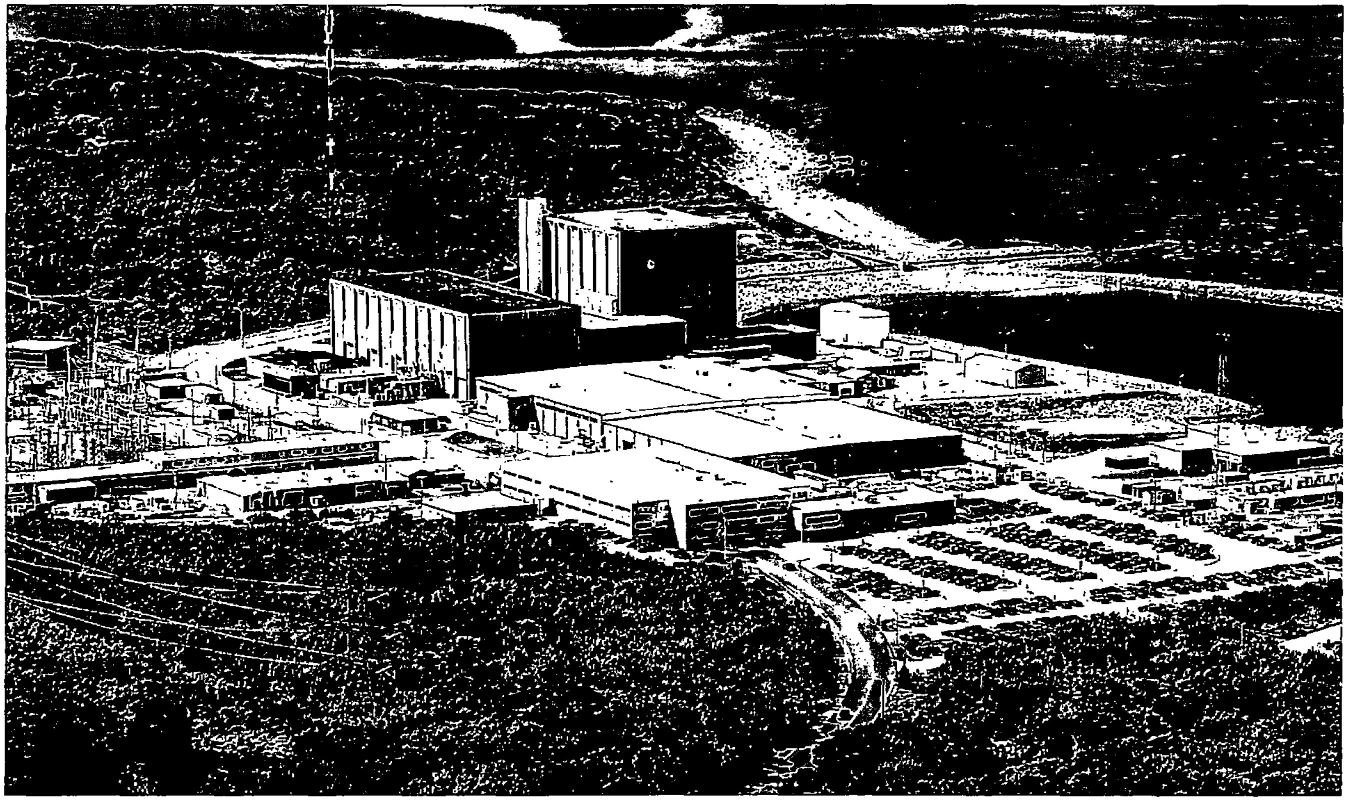
Conclusions

- On the basis of its review of the LRA, with the closing of Open Items 2.3.3.6, 3.0.3.2.10, 3.0.3.3.2 and 4.2, the staff determines that the requirements of 10 CFR 54.29(a) have been met.

Questions

Pilgrim Nuclear Power Station

License Renewal ACRS
September 6, 2007



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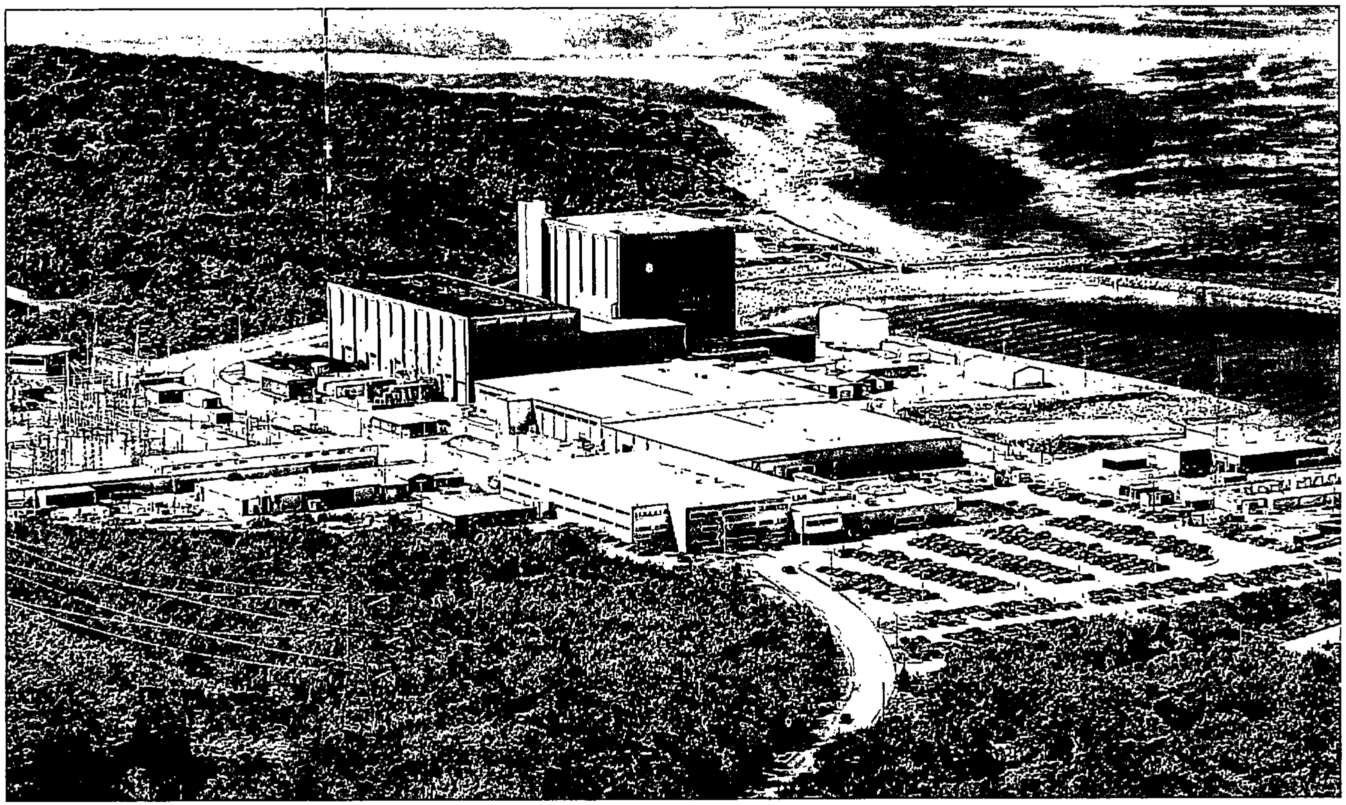
Pilgrim Nuclear Power Station

License Renewal ACRS
September 6, 2007



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Pilgrim Personnel in Attendance

Kevin Bronson	Site Vice President
Steve Bethay	Director of Nuclear Safety Assurance
Brian Sullivan	Director of Engineering
Bryan Ford	Senior Manager NS&L
Alan Cox	Entergy LR Project Manager
Fred Mogolesko	Pilgrim LR Project Manager

Other support personnel

Entergy

Agenda

- Description and Current Status
- Licensing History and Highlights
- License Renewal Project
- Draft SER (March 2007)
  - 4 Open Items
- Final SER (June 2007)
  - Open Items resolved
- Summary

Entergy

Pilgrim Description

- Located in Plymouth, Massachusetts on Cape Cod Bay
- ~ 40 miles south of Boston
- Sited on 1600 Acres
- BWR-3
- Mark I Containment
- General Electric (NSSS), Bechtel (AE and Constructor)
- 2028 MWt Thermal Power; ~ 690 MWe
- Open Cycle Condenser Cooling
- Owned and Operated by Entergy
- Staff: ~ 650

Current Plant Status

- Completed RFO-16 May 9, 2007
- Operating at 100% power
- NRC PIs & Inspection Findings All Column 1
- Next Refueling Outage April/May 2009

Entergy

Licensing History and Highlights

• Construction Permit	August 26, 1968
• Operating License	June 8, 1972
• Full Power License	September 15, 1972
• Commercial Operation	December 9, 1972
• License Transfer to Entergy	July 13, 1999
• Appendix K Power Uprate (1.5%)	May 8, 2003
• LR Application Submitted	January 25, 2006
• Operating License Expires	June 8, 2012

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Licensing History and Highlights
(continued)

Significant design improvements

- 1977- Replaced Core Spray safe-ends and piping inside primary containment with IGSCC-resistant material
- 1978 -1982 Mark I containment modifications
- 1984 - Replaced recirculation piping to address IGSCC concerns
- 1986 -1989 Safety enhancement modifications (SSW-RHR cross-tie, Direct Torus Vent to Main Stack, Station Blackout Diesel Generator)

Licensing History and Highlights
(continued)

Significant design improvements

- 1991 - Hydrogen water chemistry
- 1995 - Replaced ECCS suction strainers
- 2007 - Implementation of Noble Metals

- Spent fuel pool capacity adequate through end of current operating license
- Dry cask storage project to be initiated in 2008

License Renewal Project

- LRA prepared by experienced, multi-discipline Entergy team (corporate and on-site)
- Extensive training program provided to Engineering, Licensing, and QA
- Pilgrim and VY LRAs first applications submitted following issuance of Rev. 1, SRP and GALL
- Incorporated lessons learned from previous applications
- Peer review conducted (10 Utilities), all observations addressed
- LRA internal reviews (OSRC, SRC, QA)

License Renewal Project
(continued)

- Commitments in the LRA refined as needed during audit/inspection process (40 aging management programs)
- Commitments captured in the Pilgrim commitment tracking system
- Programs owned by site Engineering
  - 14 programs in place w/o enhancements
  - 16 programs require enhancement
  - 10 new programs

Safety Evaluation Report (SER)

- **Draft SER - 4 Open Items** (March 2007)
  - OI 2.3.3.6 Security Diesel Generator
  - OI 3.0.3.2.10 Fire Barrier Penetration Seals
  - OI 3.0.3.3.2 Containment Inservice Inspection
  - OI 4.2 Reactor Vessel Neutron Fluence
- **Final SER** (June 2007)
  - All open items resolved

Entergy

Security Diesel Generator

OI 2.3.3.6

- Region 1 Confirmatory Item to determine if security diesel components are within the scope of license renewal
- Requested support provided

Fire Barrier Penetration Seals

OI 3.0.3.2.10

- Concern on aging management of inaccessible seals
- All penetration seals are included in the inspection program

Containment Inservice Inspection
OI 3.0.3.3.2

- Potential for corrosion in the inaccessible area of the steel containment shell, base mat and sand pocket region

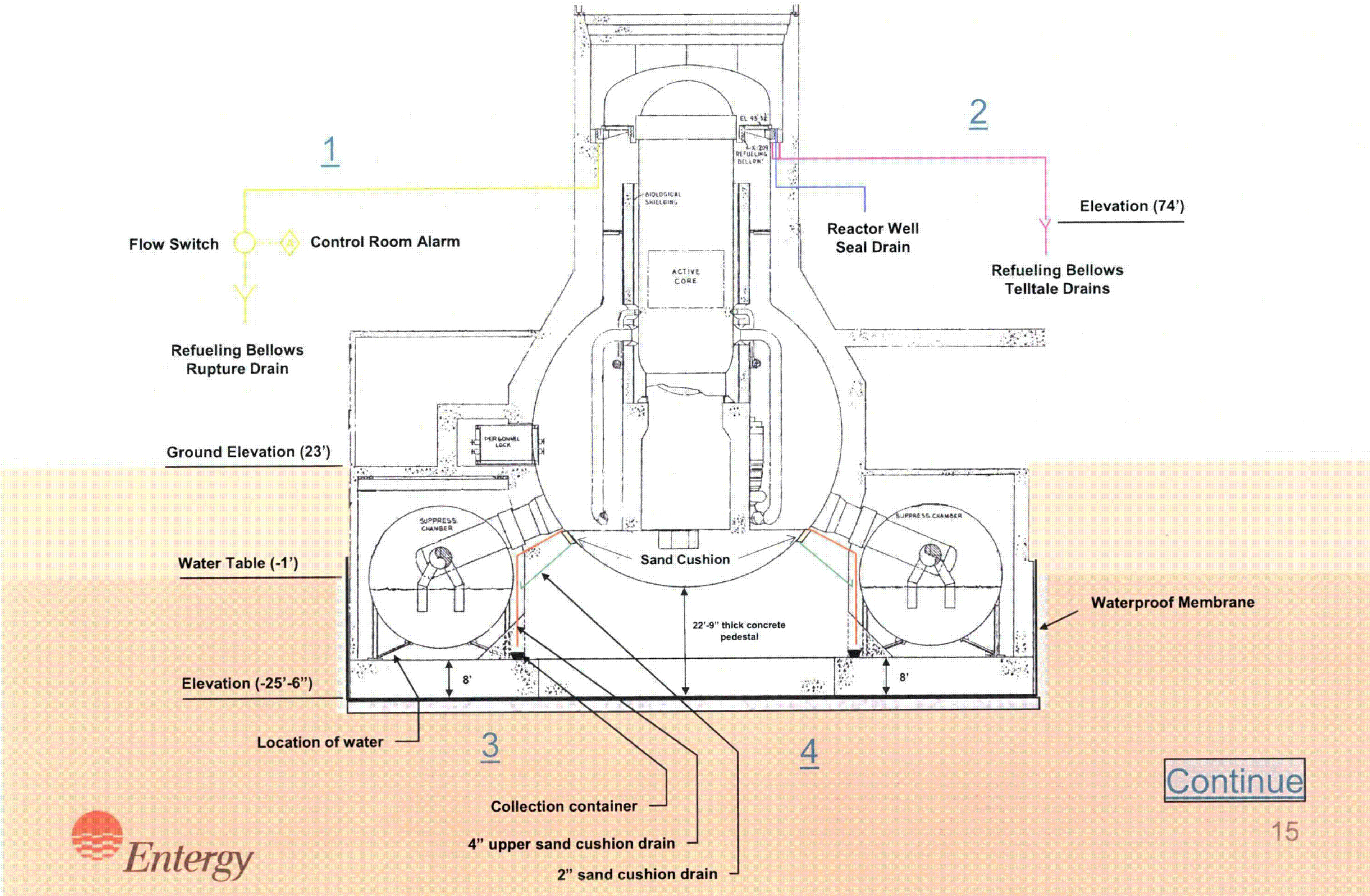
Entergy

Containment Inservice Inspection
OI 3.0.3.3.2

Drywell Shell Condition and Monitoring

- Defense in depth design minimizes potential for undetected water intrusion
- Diverse methods of prevention and identification of potential water leakage into air gap
- No refueling bellows leakage
- No water intrusion into drywell air gap
- No drywell shell degradation
- Confirmatory inspections planned and performed

Containment Inservice Inspection
Drywell Shell Condition and Monitoring



Continue

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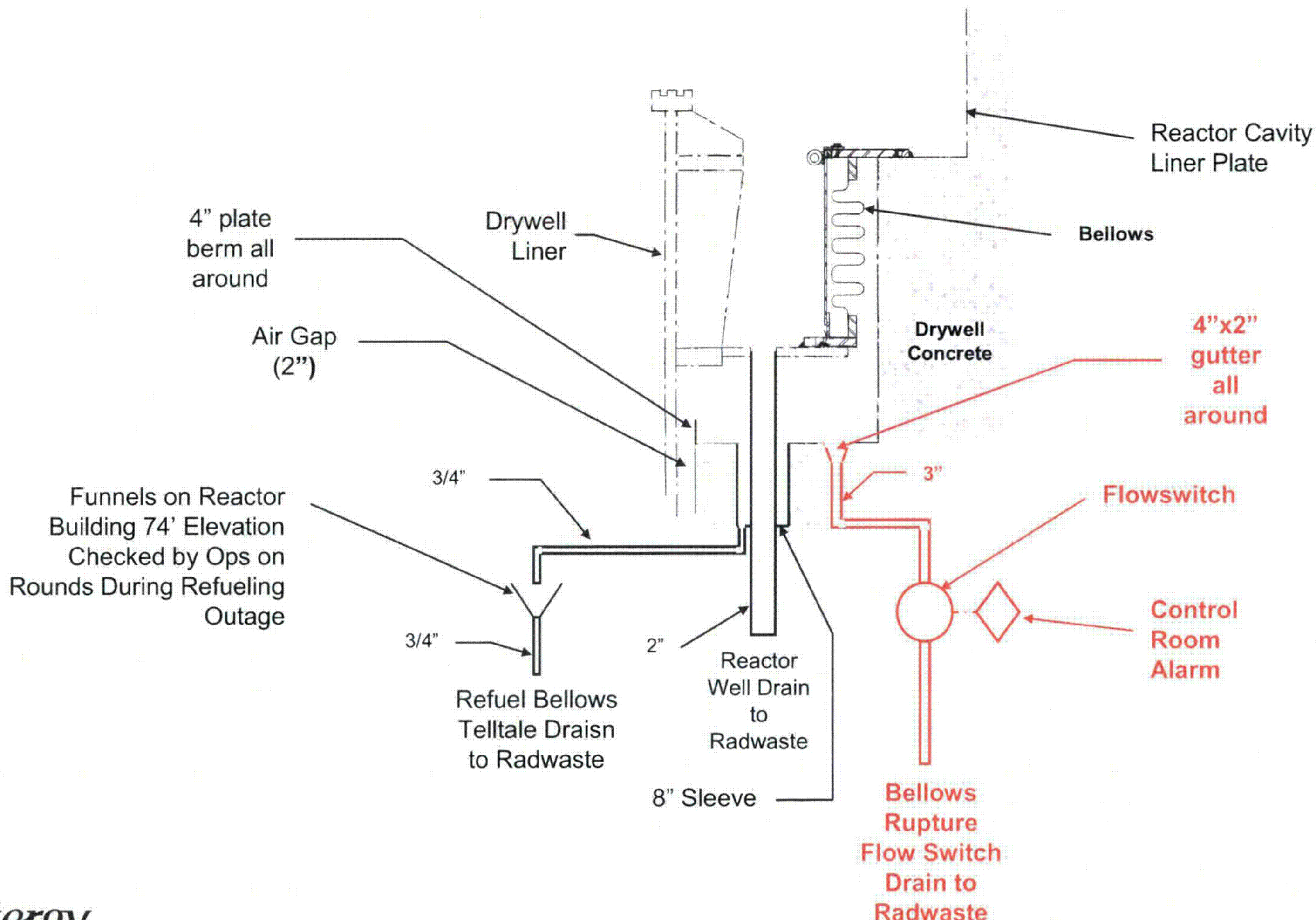
Containment Inservice Inspection
Drywell Shell Condition and Monitoring

3” instrumented drain line alarms in control room



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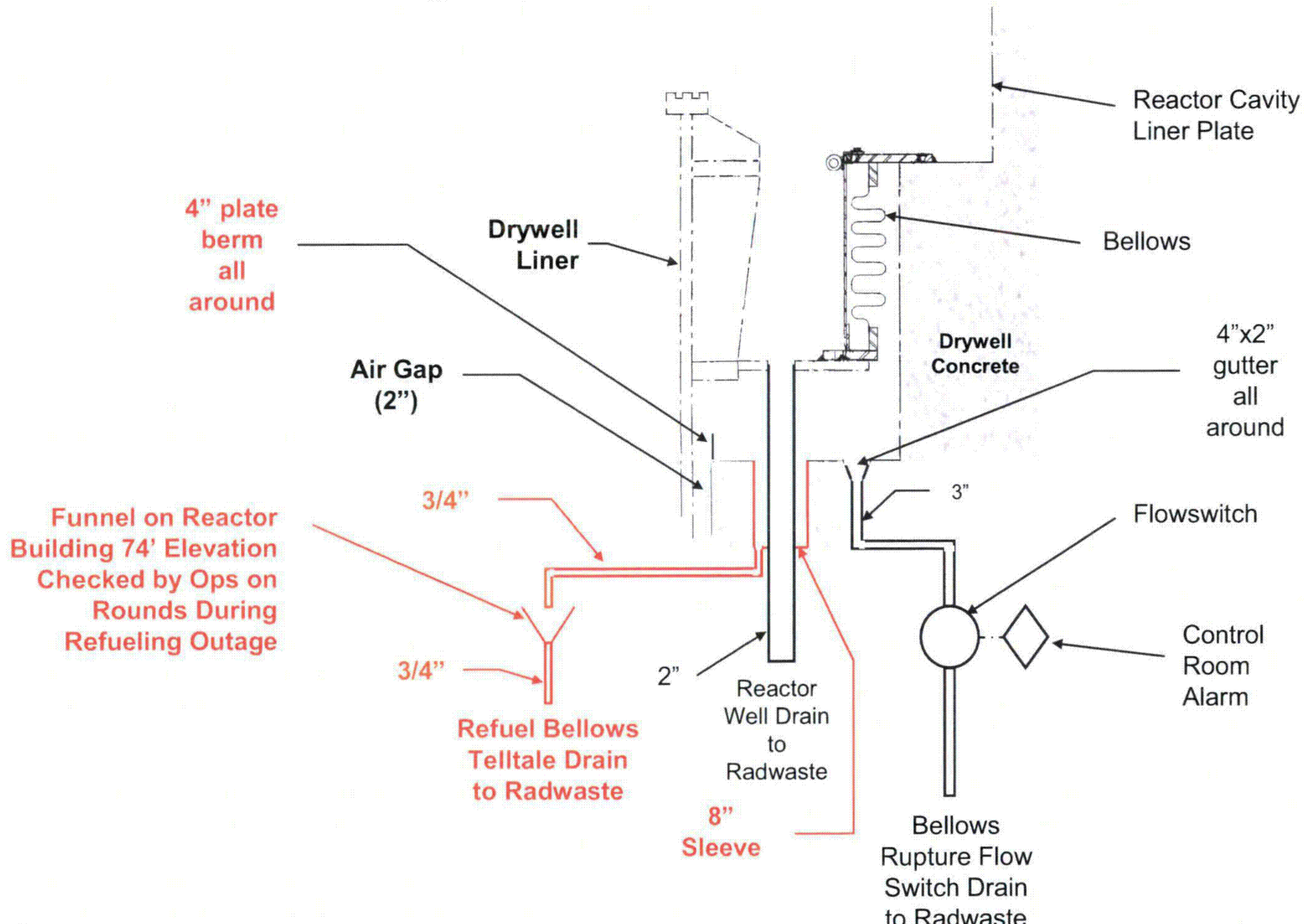
Containment Inservice Inspection
Drywell Shell Condition and Monitoring

Four ¾" drain lines which exit to 74' checked during operator tours



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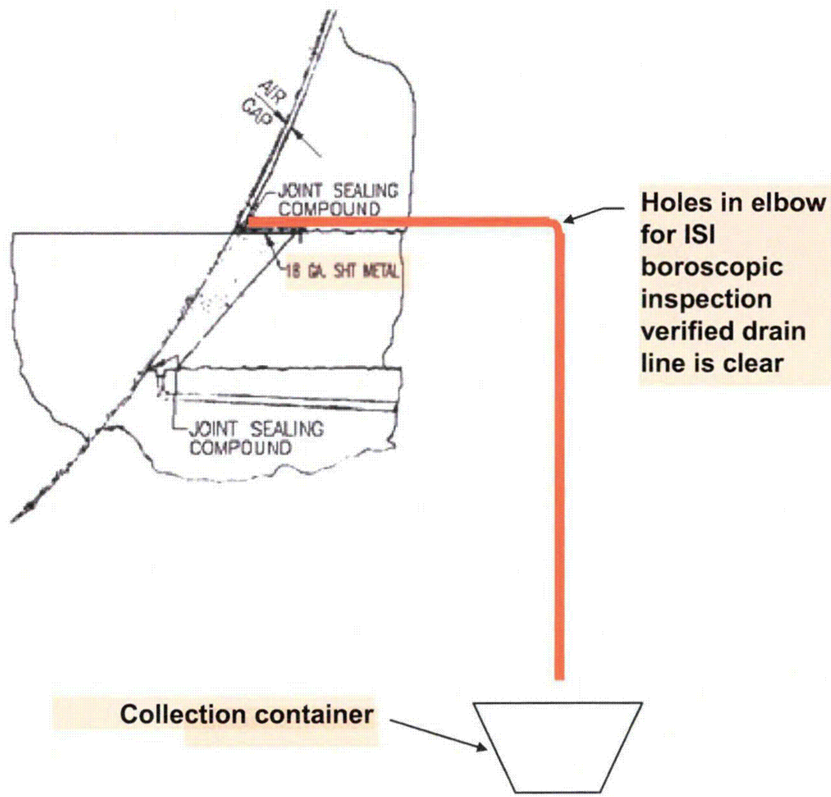
Containment Inservice Inspection
Drywell Shell Condition and Monitoring

Four 4" upper sand cushion drains drain into collection devices and are monitored at beginning and end of each RFO



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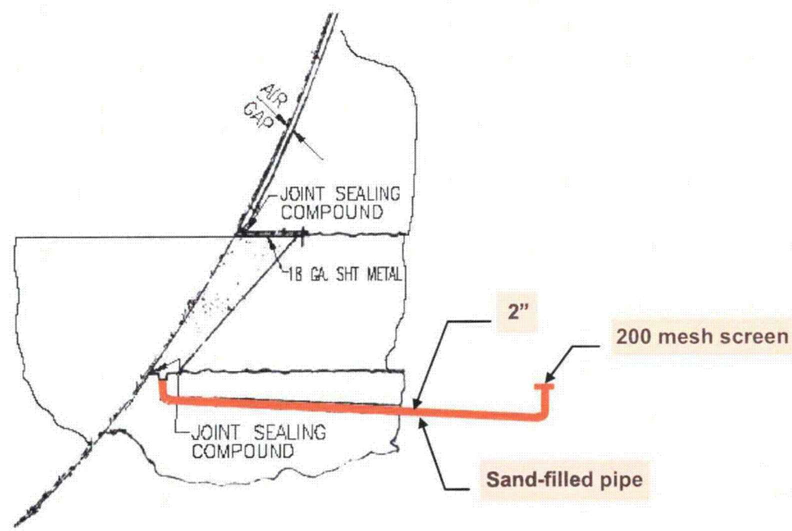
Containment Inservice Inspection
Drywell Shell Condition and Monitoring

Four sand cushion drains provide further detection capabilities



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Containment Inservice Inspection

Drywell Shell Condition and Monitoring

Past Inspections

- Limited confirmatory examinations
  - UT at twelve locations at 9'-2" elevation
  - UT at four locations at 9'-1" elevation
    - Concrete chipped out to a depth of 1"
  - UT at six locations at 72' and 83' elevations
- Verified upper sand cushion drains unobstructed and dry
- All inspections identified no corrosion

Containment Inservice Inspection
Drywell Shell Condition and Monitoring

Future Examinations

- UT at 12 locations at 9'-2" elevation
  - Prior to Period of Extended Operation
  - Once within first 10 years
- UT at 4 locations at 9'-1" elevation
  - Prior to Period of Extended Operation
  - Once within first 10 years
- UT at 72' elevation adjacent to SFP
  - Conducted every 40 months by IWE

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Containment Inservice Inspection

OI 3.0.3.3.2

Water on Torus Room Floor

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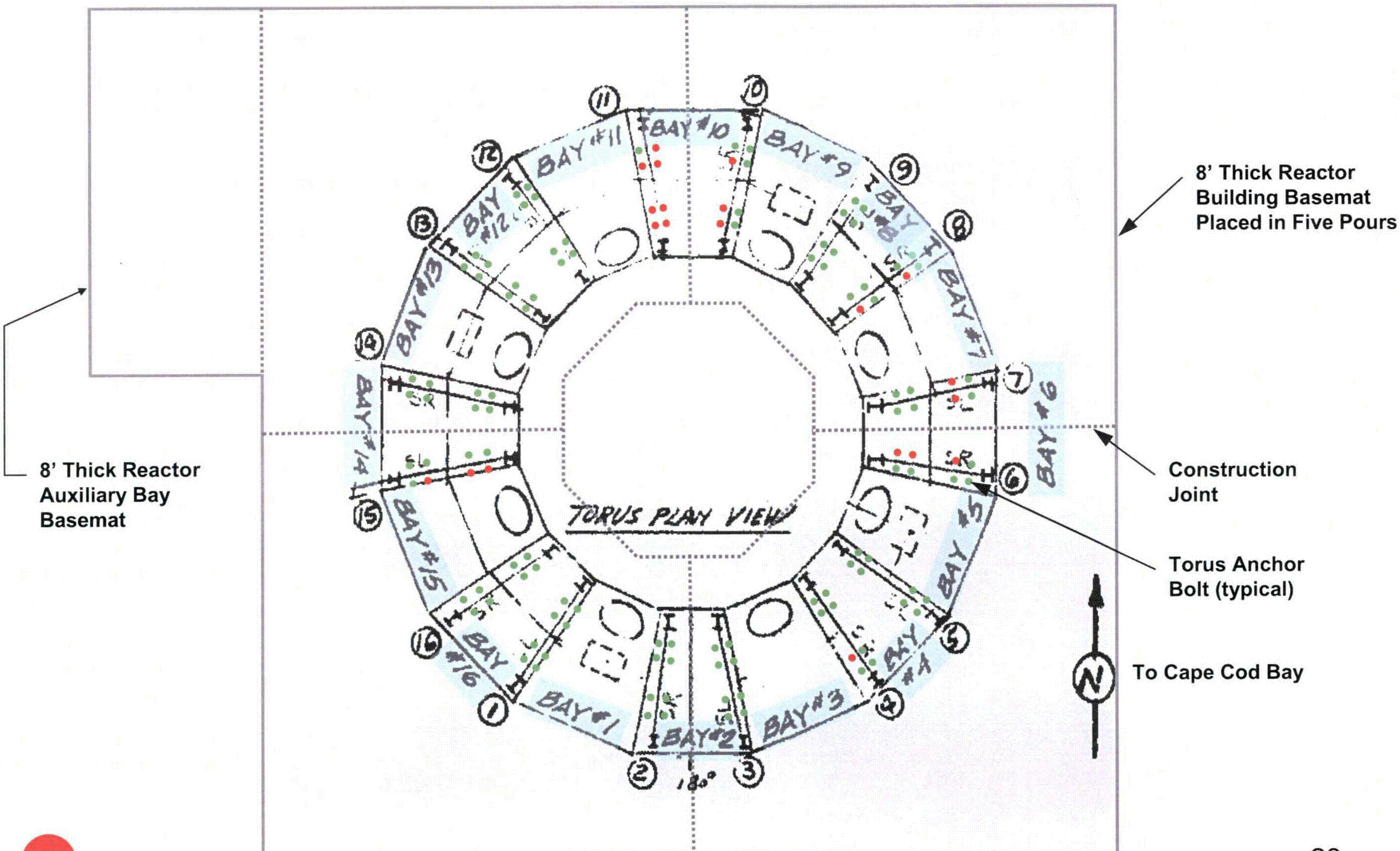
Containment Inservice Inspection

Torus Room Floor



Containment Inservice Inspection

Torus Room Floor

Bay 8

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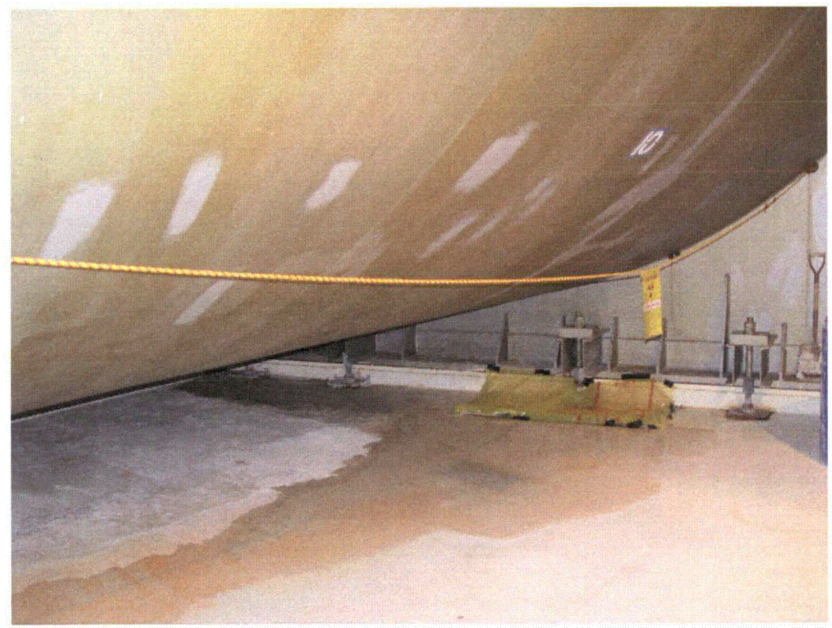
Containment Inservice Inspection
Torus Room Floor

Bay 10



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Containment Inservice Inspection
Water on Torus Room Floor

Aspects Evaluated

- Source of water
- Integrity of anchor bolts
- Structural adequacy of the reactor building
- Inspection and monitoring of water, concrete, and Torus hold down anchor bolts

Independent Assessment by Dr. Franz Ulm - MIT

Containment Inservice Inspection

Water on Torus Room Floor

Source of water

- The source is ground water seepage under hydraulic pressure
- Path is through vertical joints and zones most likely weakened by tensions generated during setting and hydration following the construction (normal occurrence)
- Low seepage rate is counteracted by evaporation
- Non-aggressive, benign water chemistry

Containment Inservice Inspection

Water on Torus Room Floor

Integrity of anchor bolts

- Implemented commitment to inspect grout and bolts for degradation/corrosion

  Two cases evaluated:

    Bay 8: Typically dry (1 bolt inspected)

    Bay 10: Typically wet (4 bolts inspected)

- Inspection included lifting of jacking plate
- Results:

  No degradation of bolt or grout

Containment Inservice Inspection

Water on Torus Room Floor

Structural adequacy of the reactor building

- Past sampling of water on floor demonstrated non-aggressive water chemistry
- No structural distress evident
- Groundwater is non-aggressive to base-mat
- Concrete Water Chemistry
  - Minimum degradation threshold limits for concrete established:
    - Acidic solutions with pH < 5.5
    - Chloride solutions > 500 ppm
    - Sulfate solutions > 1500 ppm
- Water re-analyzed to demonstrate non-aggressiveness

Containment Inservice Inspection

Water on Torus Room Floor

Future Commitments

- Determine additional actions based on inspection of bolts and water analysis, prior to the period of extended operation
- Monitor chemistry of groundwater, every five years
- Monitor chemistry of water on floor
  - Prior to the period of extended operation, and
  - Once every five years during the period of extended operation
- Inspect Structure in accordance with Structures Monitoring Program, every five years

Containment Inservice Inspection

Water on Torus Room Floor

Independent Assessment

- Evaluate functional capability of torus base-mat.
    - Professor Franz Ulm of MIT's Department of Civil Engineering
- Groundwater migration is highly localized
- Does not compromise the overall structural performance of the torus base mat.
- Does not affect the bulk integrity of the concrete slab or the overall compressive and bending load bearing capacity of the reactor foundation.
- Non-aggressiveness of ground water verified
- The localized calcium leaching does not affect the overall structural performance of the slab.

Reactor Vessel Neutron Fluence

OI 4.2

- Lack of benchmarking data to support plant specific fluence calculations for use in TLAAs

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Reactor Vessel Neutron Fluence

- Current P-T curves valid through 2011 RFO.
- Commitment to submit RG 1.190 calculations by June 2010
- Current Status:
  - Evaluated TLAAs to determine limiting fluence (RG 1.99)
    - Adjusted Reference Temperature
    - Upper Shelf Energy
    - RPV internals (top guide and shroud tie-down)
    - RPV welds
    - RPV nozzles near beltline
  - Axial Weld Failure Probability is limiting at $5x10^{-6}$ per Reactor Year
  - Limiting fluence value will not be challenged at 54 EFPY

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Reactor Vessel Neutron Fluence

License Condition:

On or before June 8, 2010, the applicant will submit to the NRC correctly benchmarked RV neutron fluence calculations, consistent with RG 1.190, that will confirm that the neutron fluence for the lower intermediate shell axial welds, at the inner surface of the RV, will not reach the limiting value of 3.37×10^{18} n/cm^2 ($E > 1.0$ MeV) by the end of the period of extended operation (54EFPY)

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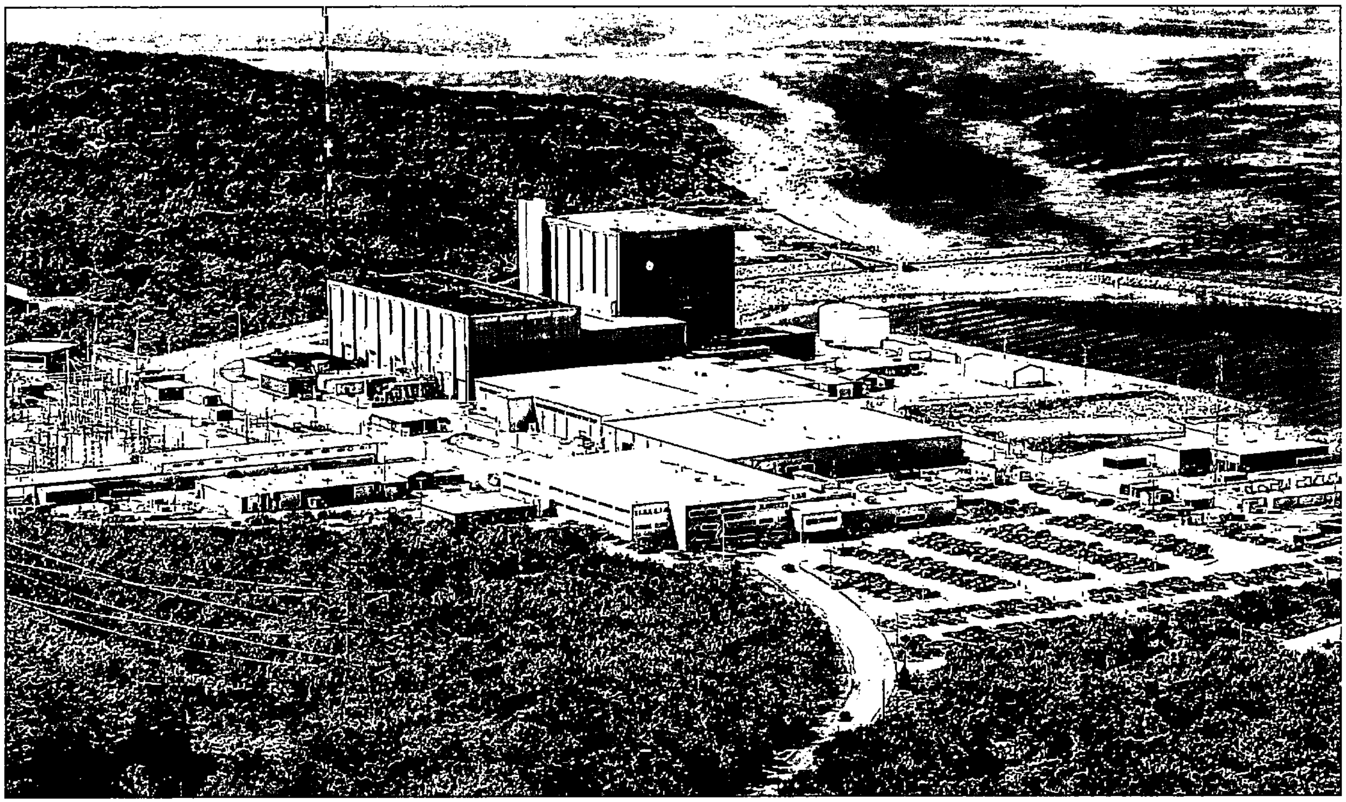
Summary

Pilgrim Station Team

- Understands plant aging issues
- Recognizes the relationship between successful implementation of LR commitments and enhanced reliability of plant SSCs
- Tracking the LR commitments and initiated implementation
- Has integrated the implementation of LR commitments into the organizational culture as an ongoing responsibility through the period of extended operation

Pilgrim Nuclear Power Station

Questions?



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