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UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
PLANT OPERATIONS AND FIRE PROTECTION SUBCOMMITTEES
REGION II VISIT

WEDNESDAY, JUNE 19, 2002
8:30 a.m.

24th Floor
SAM NUNN FEDERAL CENTER
61 FORSYTH STREET SW
ATLANTA, GEORGIA

P R O C E E D I N G S

MR. ROSEN: Good morning.

This is the Advisory Committee on Reactor Safeguards, joint Subcommittees on Plant Operations and Fire Protection.

I am Steve Rosen, Chairman of the Fire Protection Subcommittee, and also substituting for Jack Sieber who is Plant Operations Subcommittee chairman who is unable to be with us today.

On my right is John Larkins who's the technical director of ACRS, Mario Bonaco who is the vice chairman of ACRS, also Graham Leitch a member from the ACRS, Dr Vic Ransom a member of ACRS, Dr. Dana Powers from the ACRS and Dr. Bill Shack a member of the ACRS.

We also have a member of the ACRS staff with us, Ms. Weston who's a project engineer with the ACRS, Kendra Bilk and Martha Whitaker.

We are all very glad to be here. We had an interesting and exciting day yesterday at Watts Bar, and we look forward to having a fruitful discussion here today.

MR. REYES: And we want to welcome you to Region II. I know you had a good tour of the Watts Bar facility yesterday. We would like to make today better yet.

We have an agenda on the right-hand side of your folder that we believe is responsive to your request, but as the day goes along if you find a need for information different, we will do that.

The agenda that we have prepared has a lot of actual presentation by members of the staff, from management, from inspectors, resident inspectors. I think you're going to find it very engaging and direct feedback from the people who are implementing the programs.

We would like to just briefly give you a refresher on Region II just for a few minutes -- we're not going to dwell on it a lot -- before we get into the subject matter.

Just as a reminder, Region II covers the Southeast of the United States, it's ten states on the Mainland. We also cover the Caribbean; the U.S. Virgin Islands is also under our jurisdiction, and we do have licensees there. No reactors, but we do have industrial radiography, medical irradiators, et cetera, et cetera, so we have a lot of licensees in the U.S. Virgin Islands.

The region organization is typical with other regions. We have four divisions, three technical in nature who specifically you're going to hear from today. The Division of Reactor Projects and the Division of Reactor Safety are going to have members of their management and inspection staff present to you today on the different topics, because that's what's more relevant to this subcommittee.

A brief background, we have a large population of licensees. Of the 103 reactors in the United States we have

33, so we do have about a third of the operating nuclear reactors in the country, and most of them are pressurized water reactors, but we do have a little bit of a mix in terms of vendors.

In terms of fuel facilities there's nine fuel facilities in the country; we regulate five of them, so we have half of the fuel facilities we regulate here. We have a relatively modest materials licensee population on the order of 800 give or take a few every day.

But most of our efforts are in the reactor side of the house, so I think that would be relevant to the committee. And we have a large population of them, about a third of the units, so the staff that's going to be talking to you have broad experience in that in that kind of day-to-day activity in this.

I would like Bruce Mallett, my deputy, to briefly talk to you about some of the challenges we're working on in the region from an organizational point of view, and after that we will move right into the technical subjects on the agenda.

MR. MALLETT: Thanks, Luis.

I would add that the last time you were in Region II I know Dr. Powers was here, I don't know if Graham was here or not. I think he might be the sole person that was here the last time.

We have made some changes since you were here. One of the concepts we have put into the region is the team leader concept, and with the new reactor oversight program which we have people who are going to talk about later on today one of the keys to that are teams, and we have installed a team leader in each branch to not only lead those teams, but also help the branch in managing the branch.

We also think since you were last here have license renewal, and several of our plants have achieved license renewal, and we have special teams to inspect those license renewal functions, and you may hear some of that later on from some of the speakers during the day.

Also on the agenda I want to highlight one thing. You had asked for input on what we feel are the challenges, where we feel we are in the reactor oversight process.

You heard some of this from the Watts Bar licensee, I know they're not bashful in giving you some of that information.

So what we thought might be a good way to do that is to have a spectrum of individuals from the inspectors all the way up to the managers to provide you their thoughts on that this afternoon, and then allow you to ask them questions, and I'm sure you're not bashful in asking those questions either.

Luis and I thought it might give you an idea of the regional operations if we tell you what we think our challenges are, and these are right out of our operating plan, and we'll try to point out some things that we've done to address those.

They also are connected if you look down the list with the ten challenges that the chairman gave the agency not only last year in the agency action review meeting, but also this year at the review meeting.

One of the challenges he gave us was in human capital, and we have changed that a little bit in area to call focus workforce planning on retention and development of skill needs.

We established a strategic workforce plan here, and that has helped us bring together in one area a focused plan on how we're going to recruit and maintain the skills in the region that we need not only for new business, but also to conduct the inspection program and operate in licensing and reactor areas.

So several years ago a part of that was to develop a matrix of skills of the people that we need, not necessarily that we have on board, and so we established that list of skills and there were some holes in it, and that's what we used then to target recruiting of individuals.

Some of the individuals you see over here in the audience have been here several years, Billy Crowley, and some of the people have been here just a few weeks, so we have a whole gamut of individuals, and part of that is due to this recruiting effort to obtain those skills.

Our next step in that strategic workforce plan is obviously to develop people, and also to develop them before the person with that skill leaves.

For example, if we have an expert -- and, Billy, if you don't mind I'll use your name -- like Billy Crowley in the materials area, then we want to develop someone before Billy decides to retire and leave the agency for at least a year and maybe two years before he leaves, rather than wait until he leaves and then we've lost that transition. So we believe in this, we think the strategic workforce plan has helped us in that.

Luis, is there anything you wanted to add?

MR. REYES: No.

MR. LEITCH: Could you give me an idea of how many people are in Region II?

MR. MALLETT: We have around 200 I think is a good number to use.

MR. LEITCH: That includes the sites?

MR. LEITCH: There's about fifty-some resident inspectors, and there are some site secretaries, but they're only working maybe ten hours a week, so they aren't a full --

MR. LEITCH: So it's about 200?

MR. REYES: If you include part-time employees it's 222.

MR. LEITCH: Thank you.

MR. MALLETT: We at most of our sites are now down to the number N of residents; we only have N plus 1 at two sites -- or are we down to one now -- one site.

The second bullet we have -- Does that answer your question?

MR. LEITCH: Yes, it does. Thank you.

MR. ROSEN: That N you mean, that's the number of units at the site?

MR. MALLETT: That's correct. We only have one three-unit site that's operational right now, and that's Oconee. The other ones are all two or one.

MR. REYES: The policy is we have a minimum of two residents, and for those units who have three reactors we will have three meeting the number of units, but if there's only one reactor we still have two residents there, a minimum of two.

MR. LEITCH: We have Loren Plisco, our division director of projects, on the agenda later on. He can give you some more information.

And one of the challenges is obviously to when those people are up for their rotation to get them to a new site, or get somebody there to fill in the void when they have left that site.

MR. LEITCH: As you have identified here the skill set needs for different individuals, can you compare that throughout the regions so maybe there's some cooperative efforts to identify particular skills that are needed, and if one region doesn't develop it maybe another region will develop it?

MR. REYES: We're doing a little bit of that. The agency is putting together a strategic workforce plan, and in fact they're using outs as an input to that.

One of the discussions is for efficiency and effectiveness should we go in the future to a center of excellence.

Let's take fire protection for example. Should we have a fire protection engineer or two in each region, or should we create a center, meaning one of the regions will hold all the skills in fire protection as a mechanism to keep a large group with that skill, and of course you can travel in any direction. So we haven't finalized that.

What we do at the present time is we share resources. At the present time we have inspectors helping Region IV do an inspection at the Coopers Station. You may have heard of some of the agency activities there.

We helped Region I on Indian Point. We do examining of operators in another region, they help us with some exams. So we share resources, but it's not part of the integrated workforce plan.

At the present time each region has, is designed to have resources to do all the inspections, so we would expect, Bruce and I are expected to have fire protection engineers do the fire protection inspection, and metallurgical engineers. That's because the design on the region when I talked to you about the organization is identical, and we all do the same kind of implementation. But we do share resources, and the question into the future is that the best way to do that.

I can tell you specifically on the fuel facilities which is a smaller number, and we have five, that means some regions have one or none, and at the present time there's a proposal in front of the commission to make a change in that arrangement, so maybe the most efficient and effective way is to regulate all the fuel facilities from one location, and then you can keep criticality expertise, chemical and nuclear safety expertise, and it will be a better approach.

And I think on the reactor side we're probably going in that direction for certain specialties where they're hard to get, hard to keep, and you don't need them every day.

MR. MALLETT: One area in particular we have shared outside the routine reactor oversight program is in the license renewal. We have several people that I would consider experts in that area now in reviewing licensees' programs for aging, and we've sent them to other regions.

We have probably done the most license renewals, inspections in Region II of any region.

MR. REYES: When a region only has one of those we share with them our expertise and resources. There's a lot of sharing going on, but not as a design of the organization. That's what we're questioning now is should we design the organization differently.

MR. MALLETT: The next challenge area that we have that we're quite excited about some of the things we have been doing is the use of information technology. We changed this one a little bit. In our view it ought to be to reduce operational burden and gain efficiencies, not just to use the latest bells and whistles that come along.

And we've done some things that we like in that area. For example, in our operator licensing where we go out and review individual an individual candidate's job performance we're working on, in Chris Christianson's division we're working on using a -- what do you call it, a tablet? -- a notebook computer instead of taking all these pages that you record candidates' results on you have it on electronically on a little tablet no bigger than about his size [indicating], and you carry that around with you. It's going to prove much more efficient than in the past.

We are piloting some use of personal data assistants, PDAs, for inspectors to use on inspection. For routine simple things you can use a checkoff type thing. We're doing that both in the reactor area and in the materials area.

And something we just started is use of digital cameras -- and Luis may want to say something more about that -- for the residents.

MR. REYES: One of the issues you'll see later on is improve communications, and as a mechanism to improve internal telecommunications the technology today offers you a situation where you're going to go with a digital camera and take a picture of the component, the equipment, or the situation, put it in our system and not only we have it, but we can put in the inspection report, and a picture is worth a thousand words, and a way to communicate better with the public. So we are now in the field testing several brand names.

DR. POWERS: We got a demonstration of that during our visit to Watts Bar. It was I thought a terrific communication device just within the confines of the site itself.

MR. REYES: It's been very effective. As you know, we have instructed licensees to do reactor vessel head inspections, and now it's easy when the inspection is going on the inspector can go in and photograph, take pictures, and immediately we have access to a visual description of the inspection and we can share that internally. And we're looking forward to getting the whole fleet of inspectors with that equipment.

MR. MALLETT: In fact, some of our residents are getting innovative. Loren Plisco shared an anecdotal story, some of the residents are taking a picture of a material condition that's not what you would want it to be in the plant, and they're going up to the plant manager and showing him right on camera "Is this what you would want in your plant?"

MR. REYES: It's faster than paper.

DR. POWERS: The one that was described to me was of some leakage, and they could take it in the motion picture mode and they could come up and say "Did you understand that the leakage is this bad?", and they could see it.

MR. REYES: It is a very effective tool. We're just doing field testing with several models and brand names before we do the big investment, but we made the decision to go forward. We just want to make sure it's a smart decision.

MR. MALLETT: The other thing we're doing in this area that's proved very effective for us is we have what we call docking stations now. Instead of permanent computers on the desktop we have a station you can dock it or plug in essentially your laptop, and you can take that with you in the field. It's saving inspectors having to take volumes and volumes of things on paper; now you just have one little CD, even the regulations, and just plug it in if you need it, and that's worked out very well for us.

The next one I would combine with the last one on communication. You know, one of the agency's challenges was to work on the communication, and we've done several things there.

One is internally we have our own communications plan to help us improve how we communicate not only up and down the chain, but also across organizations between the division of reactor safety that Chris Christianson is the division director of, and the division of reactor projects that Loren Plisco who is going to speak to you later is the division director of, and we've found that plan is a good tool to guide us through some planned activities to try and improve in that area.

One of the things Chris's division has done a lot of is meet with their staff in small focus groups for a what-would-you-like-to-have changed, and kind of a -- what do you call it, Mark Lesser, a three-sixty review I guess of where we're going and what we ought to do, and that's proved fruitful for us.

Externally we tried something that we're working on is instead of the meetings we have had just with licensees at the end of the cycle, we have targeted some meetings with local officials, and even a town meeting with Commission Diaz, so what we hope to gain out of that is interface with the public to answer questions not in response to a particular event or issue, but at a time when you're not in that scenario we find we get a lot more candid discussion, and I think it proves to improve the public's confidence in us.

When you're responding to an event in a meeting you're always coming from the negative side of trying to say what we did and respond.

The last bullet there is to improve the use of the significance determination process for after-inspection findings. I won't go into any great detail on that because we have Loren Plisco who is going to talk to you about that in his presentation, and Charlie Payne in the fire protection is going to talk about that.

Probably the overall challenge in Region II is we're working on an up-front plan to determine how much time we should spend on the Phase III portion of the significance determination process rather than run the model to the same time frame so that we don't have cases that are three years old we can try to have some scope up front of how much time do we want to spend determining is this a white-white or a full white finding for example.

That's the end of our introductory remarks. If you have any other questions, we'll be glad to answer them.

DR. POWERS: Some questions about the prioritization, your district thinking about prioritization.

You get a bunch of findings in that you say, well, I've got a stack of findings here, I think they're probably green, you know, just looking at them, but I've got this other one that's more complicated, and do you set those kind of green ones aside and work this complicated one, or is there a queuing process, or how do you think you would work this thing?

MR. REYES: Well, what we have tried to do, and I think somewhat successfully, most inspectors screen quickly out in the screening process the ones that are not significant, and I think this afternoon when you talk to them I think you'll get that feeling.

The ones that now have some significance and then you're trying to determine Phase II or Phase III and all that, we engage our senior reactor analyst, and basically use all the resources to help him do that.

The problem is that they're very resource-intensive, and specifically in some areas. In mitigating systems it's not that difficult.

We have been at it -- the technology has been at it as you know for a long time. Fire protection is very frustrating. We have the previous problem with security, and we end up changing our whole security significant determination process, so the areas we're using the risk is fairly new, they're really resource-intensive and --

DR. POWERS: Well, that's basically what I'm asking. Say you ask your senior reactor analyst who's the one to attack this, I mean that would go and process one at a time. He's got to figure out which one he picks up.

MR. REYES: Yes.

MR. MALLETT: Exactly right.

MR. REYES: We're trying to follow the ones we had to him, if you follow what I'm talking about.

DR. POWERS: I'm still talking when it gets to him he's got five of them, how is he picking them up? chronologically?

MR. REYES: We have, organizational-wise we have two senior reactor analysts, and they have particular plants assigned, so first we divide the workload.

And the second one is basically when they arrive. We try to do them by when they arrive, but what happens -- I'll give you an example -- you've got a fire protection on one that's taking all of your time and we're trying to interface with headquarters on it.

The second one comes in which is straightforward mitigating systems. That one gets work and probably would get resolved much faster than the other one. We've got another one with shutdowns, in the shut-down mode, and it will take us a year to get through -- and that's a give and take as we go and have headquarters' help.

But they come in sequentially, and one of the senior reactor analysts is going to talk to you this afternoon, and I would encourage you to explore this further with him. But we have to work by plant between two of them, and then they process them as they arrive.

Remember, we're dealing with the site to correct the safety issue, so the fact that colorizing, risk assigning an event may take a year or two has nothing to do with the field. The field has been corrected or compensated somehow. We do that right away.

MR. MALLETT: The other thing we did which I think helps that process is we had the senior reactor analysts reporting to the division director. We changed this year to have them report to branch chiefs in Chris' division of reactor safety. We think that gets them closer to where the decisions are made as to which one you work on first.

MR. REYES: Right.

MR. MALLETT: And Mark Lesser is going to talk to you about Alloy 600, but he's also branch chief in that division and may want to share some things.

DR. POWERS: I understand. I have no idea what the right way to do it is. Actually I'm curious how you're thinking about it.

MR. MALLETT: We're working on that. We don't have it solved totally yet.

MR. REYES: It's by plants, and then how they come in into the pipeline and they get processed, but some of them get backlogged.

DR. POWERS: If Steve would just run his fire protection subcommittee correctly, we'd have all this fire protection done real fast; right?

[Laughter.]

MR. CHRISTIANSON: Additionally on the SDPs which are greater than green, we have established a tracking system for them, and every Wednesday we have that DRP division and the DRS division in a morning meeting get together and go over the status of that to make sure that everything is tracking okay and that we understand where it is in the process.

And that's to try to -- we have an internal goal of 90 days. We don't make it all the time on some of the complicated ones, but that's what we're trying to do on the SDP process.

MR. MALLETT: One of the reasons we did that was we got some cases that were out there a long time, and we said why did this take us this long, and in looking back we felt that we should have done a better job up front in deciding how much effort are we going to spend. But we haven't solved this thing.

DR. POWERS: When you have a chance if you can go back and look at things and say, now, what tools should we have had to accelerate this process. You know, that's feedback that's really useful to us.

MR. MALLETT: You're going to get that this afternoon.

MR. REYES: You're going to get a lot of it.

MR. ROSEN: Are you keeping up with the flow of findings that you have to do these analyses on, or are you falling behind?

MR. REYES: We were not, and then we established several things such as the tracking mechanism, we talked to the program office. One of the problems is that we're not going to invest any. For example we had one that still is not finished and they're in shut-down, and those resources are down limited to one or two individuals in headquarters, and so the reason the reason why the agency has some particular topics are limited, so we have met with Sam Collins, the director of the office of NR, and he understands the situation and there's changes being made.

Today we're much better off. I think we're getting closer to the goals that we want to accomplish.

Now, one thing I should have said before was while we were talking about structure, we're trying to increase the knowledge of all the inspectors on risk, because what we would like to do is exactly what you talk about, quickly process those that have no significance so we can leave the limited resources we have such as senior reactor analysts and all that to only have a handful, so we only have a handful getting to those that are the real significance, and they don't have to deal with the other ones that can be disposed of rather quickly.

So we're sending a good number of our inspectors and managers to the whole series of courses that the SRAs went to just as a mechanism to keep those limited resources dealing with the important cases, and be able to use the larger population to process the ones that don't have real significance.

DR. POWERS: You will be gratified to know that this has worked, by the way.

MR. REYES: Is that right.

DR. POWERS: I was walking through with your resident looking at trains and whatnot, and he was explaining to me how it was counterintuitive what the risk significance of the various trains were, and why, and he's very knowledgeable in risk technologies.

MR. REYES: And I don't know if you remember, we have an amendment to the commission that as of December of 2001 we would have every resident go through the early-on training, and we did that.

And what we're trying to do now is we're trying to nudge that up, because we think if the inspectors and their first-line managers can deal with most of the flow, the ones that are no significance, then we can be more effective with the ones that are because the senior reactor analyst has a less number of issues to deal with, and they don't get distracted with the ones that could have been handled by the staff.

DR. POWERS: This was a very difficult risk analysis to do mentally.

MR. REYES: Oh, yes.

DR. POWERS: And he lined it up for me very clearly, and so, yeah, I would say your residents based on that interaction are getting very knowledgeable and very sophisticated.

MR. REYES: It's a very hard goal, I have to tell you, because we have competing interests as you know. But we are determined to do it, and I think it's paying off.

MR. ROSEN: I think you've got a very large problem here, Luis, in that order to maintain both the external and internal confidence in this whole process you need to not have important events that are risk-significant linger very long.

MR. REYES: We agree.

MR. ROSEN: And in that because the input of the equation is not under your control. The class are going to have findings, and you can't control how many that is going to be, so at any given moment, any given morning you could come in and find your nice work plan disrupted by two or three major findings of the 33 sites in your region.

MR. REYES: Yeah.

MR. ROSEN: So given that, if I were in your shoes what I would want to do is make sure I keep that backlog squeezed down real tight so that I don't have the vulnerability of having a number of findings coming in on any given day that overwhelms the rapid remedial capability.

MR. REYES: We are relatively lucky compared to the other regions. Our two senior reactor analysts are graduates from class number one, and we have had no turnover, we have had no turnover in the senior reactor analysts, so what that has done for us to help us -- and I agree with you -- and that is that they're very familiar with the facilities, and since we have them assigned split, and they're familiar with previously-done risk analysis at those assigned facilities and have helped them.

But I can tell you my colleagues in the other regions have a little more difficulty, they have had turnover of the senior reactor analysts, and being new to the plant, and being new to the business is just -- it just aggravates the problem you're talking about.

MR. ROSEN: And I would think, though, that the one possible way to improve your effectiveness a great deal would be to lean on the licensees quite heavily in the sense that most licensees have the scope PRAs for at least three internal events, and maybe for external events as well, and that your first reaction to a serious finding seems to me ought to be a meeting of your resident, and maybe even the SRA with the licensee and ask them for their take, and then you can compare that with yours before you light off independently and try to create a new wheel.

MR. REYES: We're doing some of that. Because we have the SRAs here for a long period of time and they have assigned facilities we have a couple of matrixes that we use to help us in this.

One is the name and the interface for each facility in terms of risk, so we know who to call and who to talk to. The SRAs can show you that.

The other thing we have done since implementation of the program is that we have taken each facility in Region II and developed a predetermined set of events and calculated the risk for it. In other words, at midnight I pull out this sheet and Summer had singular tube rupture I already have the number, and the licensee has agreed with that number we have calculated, and we have had a dial-up. So I can tell my boss, by the way, we're in this, we're in this bracket. It's not perfect, but we're in this bracket.

MR. ROSEN: You may not have had that exact event, but knowing what one of the things is you can say that the difference between that event and his event is probably to make this less significant or more significant.

MR. REYES: Correct. And we can tell them, by the way, there were many malfunctions in addition to the main event so that as a minimum the risk is this, and probably worse, or higher risk.

MR. ROSEN: That fact he's very familiar with in the human performance area with the anchor action technique that's in some of the successes where you set up operator actions and you decide what the risk of a given operator recovery action, is it likely that an operator will recover under certain circumstances, you get a panel of experts together and do that, and then when you get another event you say how complicated was that compared to the one you just analyzed, so you're actually using the same sort of technique as used in the success likelihood index method, and I think that's a good thing to do.

MR. REYES: In fact this matrix is kind of intuitive. We look at a set of examples like a steam generator tube rupture, and the numbers vary from plant to plant in some cases significant, and then when we say why and then it gives insights about the plant. Some of them have added additional makeup pumps for operational and safety reasons so they have extra, they have additional resources that make the changes significantly. And we have now those insights in a very handy area available, we'll be glad to share that with you if you're interested.

It helps us a lot, because we agree with you it is very important that we handle events and findings in a rather expeditious way for public confidence, and we would like to get the results.

DR. SHACK: Who generated the matrix for you?

MR. CHRISTIANSON: The senior reactor analysts.

MR. REYES: We took the SRAs, senior reactor analysts who are assigned to the plants, and we say, okay, let's come up with a matrix. Say at midnight on Sunday -- I'm not a practitioner, so I told them at midnight on Sunday -- I said when you guys are here and it happens during the day it's easy for me, I knock on the wall and say come over here and we get it done.

But the for the worst-case scenario Sunday at midnight I said I have to have a mechanism to talk to the senior managers in the agency, and I would like to have an idea of the zone we're in, how bad it is. So we created this matrix and then filled the numbers, and they calculated them, and we actually exchange out with the utility, and they know we have this matrix, and they know we agree in general terms with the number.

And what I wanted to do too was that I found out that the utility management had this problem too. We had an event where -- and what I forced them to do is if plant managers know I carry that in my briefcase so now they force their analysts to give them the list of key events and what the risks are, and so I wanted to force a change in the utility to this risk mentality, and we're being somewhat successful with that in putting this matrix together.

MR. ROSEN: They followed all this through when the reactor oversight process was set up, but the fact that you're doing these things, and the fact that the licensees for their own health and safety are picking up on it is a very good thing that the agency and the licensees are working together to understand risk management, which is what we're really doing.

MR. REYES: Yeah.

MR. MALLETT: The other thing we're doing which we have also preached this, we have an advantage here we're close to INPO, so we go to all their new INPO managers seminars, and Luis has been on the agenda, I've been on, Loren has been on there, and we go and we preach this to them that here are some lessons learned that you ought to have when you respond to an event, and here are some issues.

That's been quite effective interchange, and so eventually you get to every manager in their organization with that concept. So now we have managers, senior managers decide to call us very early as you suggested during an event to just say, hey, this is where we think we are, where do you think you are.

MR. REYES: It's very important I agree to have that dialogue.

Okay. That's all we wanted to talk about in terms of the general discussions. We have a detailed agenda and we're almost on schedule.

Do you want to continue with the agenda the way it is, and then you let us know when you want to pause.

MR. ROSEN: Let's move on. We'll try to get most of the agenda behind us by four if we can.

MR. MALLETT: I see people looking at coffee. We did have a break built in after Mark Lesser's time.

MR. ROSEN: Let's keep rolling.

MR. LESSER: Good morning. My name is Mark Lesser, I'm Chief Engineering Branch 2 here in Region II, and I would like to talk about some follow-up of some of the Alloy 600 issues in Region II, and specifically we'll talk about the latest on V.C. Summer pipe crack that occurred in 2000, and what your status is on follow-up on Bulletin 2001-01 control rod drive mechanism vessel head penetration cracking, and the temporary instruction that our inspectors are doing.

Okay. The V.C. Summer crack follow-up activities, a brief refresher, in the fall of 2000 the licensee during their outage identified a 2 1/2-inch long axial thru-wall crack in a 'A' hot leg weld, and they cut out that section, a 12-inch spool piece, they cut that out and rewelded it.

Basically they did a root cause evaluation, we did a special inspection. The cause was attributed to primary water stress that caused the cracking, and complicated by, or contributed by high residual stresses from multiple weld repairs during the field installation, the field construction of that weld.

DR. BONACA: Did the root cause ever question why they didn't know of the cracks previously in other inspections?

MR. LESSER: The root cause looked into that, and they had done their ten-year ISI a few years before that, and with ultrasonic testing, and --

DR. BONACA: They didn't see it? '

MR. LESSER: They didn't see it, and they didn't see this crack if it existed, and there's the possibility the crack did exist at that time, and that basically the equipment there's a possibility that a lost -- well, actually a lost coupling, with the ultrasonic it did not have a good coupling at this particular point on the pipe, and so that was basically -- you know, we didn't see that. So they felt that that was a generic problem.

DR. BONACA: There wasn't only that crack, there were other cracks in other nozzles, and they could identify --

MR. LESSER: Yes.

DR. BONACA: -- in the previous inspection the year before the primal crack, so that crack must have been there.

MR. LESSER: It was there.

DR. BONACA: The reason I'm asking that question is trying to build some more confidence in inspections.

MR. LESSER: And there are briefings that are ongoing. For instance, improved sled design for transducers that are running along side the pipe wall to reduce the possibility of a loss of coupling.

MR. REYES: One of the contributing causes is -- and, Billy, you just jump in if we do it wrong -- the sled, the machine that runs over the pipe with the sensors, the older designs didn't have what you would call a shock absorber, didn't have robotic articulated for the sensors, and it turns out that this weld in particular which was a weld made by hand it was rough, it was rough by today's standards, the sled actually lifted the sensors over that area, and it's hard to prove, it's hard to prove it but with today's technology their articulated sled is much more likely to keep the sensor in touch with the pipe and the weld in question.

Billy, anything else to add to that? So technology, I think the new technology is going to assist in trying to eliminate some of the contributing causes.

MR. CROWLEY: All of them were similar, they were all manually welded, and the inside surface which the UT transducer was traveling on was rough, which didn't provide an optimum surface for examination.

MR. CHRISTIANSON: Bill Crowley was the team leader for the special inspection for the pipe crack issue at V.C. Summer.

MR. ROSEN: You just said something that interests me. You said the UT inspection was from the inside surface?

MR. CROWLEY: Correct.

MR. ROSEN: How big a pipe was this?

MR. LESSER: 29-inch inside diameter, 2 1/2-inch wall thickness.

MR. REYES: The biggest pipe you have on site, all of their main steam.

MR. LESSER: Right next to the outlet from the reactor vessel, so it's fairly close.

DR. BONACA: That to me though would be an essential part of the root cause if I understand it, and also communication with other licensees if it is an issue of contact.

MR. REYES: And in fact every licensee who did the inspection subsequent to that, that articulated sled was in high demand because nobody wanted to use the old technology, worry about the sensor not coupling well based on an imperfection of the pipe, and all the licensees are aware of, one demanded the contractor use the new technology to make sure the coupling was there.

DR. BONACA: One last question I have, clearly that experience shows that the use of eddy current combined with metric [?] is ineffective to identify to a T the existence of a crack.

Is this being expanded in use, or is it too burdensome?

MR. LESSER: I can tell you I sat in some meetings where the rule of the industry is taking the lead in working with NRR staff in the materials reliability project referred to as the MRP. They're doing a lot of work in where all the Alloy 600 is in the plant first of all, identifying all the dissimilar metal welds, and trying to identify the best technology to find these, to gather data.

In fact, one of the pieces of data is the follow-up inspection at V.C. Summer which they did this last spring, so there's a lot of work going on there between the industry and the agency to find what needs to be done.

MR. REYES: The problem too in testing is that there's no baseline. The plants have been operating now for 25 years, 20 years, and this was not done during construction, so you are going to have a lot of indications, we saw that at Summer, and it could be as simple as a scratch on the pipe from construction, or it could be incipient developing of a flaw, and then you would have to dispose of all that large volume of information, so there's some hesitation from the industry from a practical point of view on if we this then what are we going to do, is the regular going to impose us to stay shut down until we analyze every one, so that's part of the exchange with the industry.

DR. BONACA: The reason why I was pursuing it, we are reviewing license renewals, and they depend so significantly on the quality of the inspections, so I was pursuing that to see if you have confidence that they have tried hard to do it right, or if it was simply an inspection that was maybe split up somewhat.

MR. REYES: Let me ask Billy to add to that, because he's been in the team inspections for all the license renewal inspections in Region II, and we've done the most, so Billy, do you want to add to that a little bit.

MR. CROWLEY: I didn't quite understand what the question was.

DR. BONACA: We ask you know are doing the regular license renewals, and we depend on these programs that include particularly these kinds of inspections for the license renewals. As the plants are getting older these kinds of things will be getting more common, you may get more cracks that may expand to open a crack, so the point I was trying to understand is do we understand the cause of this completely, and can we be confident that when the next license renewal application comes in and they say yes, we have performed in-service inspections that we can be confident of that.

MR. CROWLEY: I think a lot depends upon what comes out and what's going on in the industry. We're trying to understand what needs to be done to get the best inspection, do we need to add eddy current. You know, if so, a lot of work has to determine what the acceptance criteria are.

So I feel like with the NRC and the industry together looking at this issue and determining the best inspection methods, you know, we can be confident we're doing everything we can to preclude passing something like this up.

MR. REYES: The utilities are very sensitive to this for a lot of reasons in terms of having to put the unit out of service for long periods of time. We've seen a lot of work in trying to identify it early, and I'm looking at Billy here, but we feel comfortable with the extent of what they have done, but this Eddiker & Tussen [?] is still an issue on the table.

The biggest issue from where I sit is coming up with an acceptance criteria that the industry and the regulator can agree on, because it becomes a practical matter once you get all the information, what do I do with all this information.

DR. BONACA: I just have this last comment to make, but I just thought of a question. You mentioned the root cause was TWSC, and it was allowed to propagate right through the whole nozzle. That's a long process, and it just goes to the heart of the issues of license renewal because there's a crack that's going to elongate through a long time, and we depend on those programs for saying yes with confidence, we have confidence that we can go 20 more years with that plant. And we are likely to see some of these issues crop up more frequently now as the plants are getting older.

MR. ROSEN: What was the agency's response to all this? If we're getting this kind of finding in more than a few questions it could put into question the whole process.

MR. LESSER: At this point the agency has not put out any new regulations or requirements for that, and there was some uniqueness in V.C. Summer. This was field welding versus shop welding.

But as I said, we're in the process of looking at the generic --

MR. ROSEN: Excuse me. Are you saying that this was the only field welded pipe in the region?

MR. LESSER: I didn't say that.

MR. REYES: On the location of the large line, the hot legs and cold legs, this was the only one that was started and finished by hand -- is that right? -- and all the errors were grinded out. From there on they started the automatic welding process on the other legs at the station.

MR. ROSEN: At V.C. Summer.

MR. REYES: At this station.

MR. ROSEN: You have 33 plants out there.

MR. REYES: Yeah.

MR. ROSEN: How widespread was that kind of manual operation? is the next question.

MR. REYES: In the early days it was common.

MR. ROSEN: Common.

MR. REYES: In the early days.

MR. LESSER: This was field welded with -- the other thing was multiple welder errors.

MR. ROSEN: That was the situation that was at the root cause of this, not PWSCC, which is field-welded, multi-repaired nozzles is common, so --

MR. REYES: Well, the licensees, because we need to follow on your question --

MR. CROWLEY: Not all of them were field welded, not all the dry metallic welds were field welded.

MR. ROSEN: Common doesn't mean all; common means half, or every plant might have one or two, so that should be the focus of what you're thinking about.

MR. REYES: Knowing that, the utilities took that information, and they can tell from their records which one was what we call a problematic during construction, meaning it had to be repaired many times, and grinding, and all that, and they went in and specifically looked at those, and the results we have back we haven't seen this again, it doesn't mean that we won't, but they realized that if you have all these conditions you are more likely to have a problem, and they have been looking at that.

The industry was really taken aback by this his event because of its implication, and we have a lot of PWRs in Region II, so we have followed this closely.

I guess time will tell, but so far we haven't seen something similar.

MR. ROSEN: But I wouldn't take a lot of comfort from that, because this was just the fall of 2000, and so it's the summer of 2002 and not much time has elapsed. When you think about crack propagation rates and the kinds of --

MR. REYES: And I was thinking of the older units that are more likely to experience this, and we have a few of those here. So far -- they actually looked, they went and looked at this situation, and it hasn't shown up. Doesn't mean we're not going to see it.

MR. LESSER: Getting back to the other cracks that were found, the second bullet, when they did remove this spool piece and examined it they used eddy current, and they found other cracks in the unit with eddy current shallow cracks, and as part of their extent of condition looked at the other loops with eddy current, and they found cracks there, generally shallow cracks of the size-length of about a quarter inch to about six tenths of an inch was about the size.

The licensee back in 2000 did a structural integrity analysis that was submitted tot NRR staff who reviewed that and accepted those flaws as is for one cycle of operation with the understanding that they would go back at the next outage and inspect.

And so V.C. Summer's next outage was just this last spring. They did two things. They not only went back and inspected, relooked at the 'B' and 'C' hot legs, but they also did mechanical stress improvement process.

This is actually a clamp that's put on the weld, and they actually compress that, squeeze the pipe to try to eliminate the tensile stresses on the inside diameter of the pipe.

MR. REYES: What it does, it changes the surface on the inside of the pipe and the weld there, the starting location of the PWSCC.

MR. LESSER: And actually they're using about 20,000 pounds of pressure to actually plastically deform the weld, the pipe about 1 percent and actually get a 1-inch reduction in circumference of the pipe.

They did this on the 'B' and 'C' hot legs. We had an inspector observe some of those activities, and NRC research also had their contractor who was on the original special inspection team come back to V.C. Summer and look at the new, the later nondestructive examination activities that they were doing. They inspected 'B' and 'C' hot legs before mechanical stress improvement and after mechanical stress improvement.

DR. SHACK: Do other licensees, your BWI licensees in Region II use MSIP?

MR. LESSER: It has been used in -- yes, it has been used in the past on BWRs, yes.

MR. REYES: This is the first PWR that we know of. This is the first BWR that we know of that it's been used on.

MR. LESSER: The eddy current inspections this year showed good correlation with the results of 2000. There were no new indications in 'B' and 'C,' and basically any changes in length that they observed they attribute that to measurement uncertainties and different technologies. And the licensee concluded, and the NRC concluded there was no growth in the crack length for any of those. There's four indications that follow, a total of four indications in the 'B' and 'C' hot legs.

And the NRC staff approved V.C. Summer for start-up for another, one more cycle of operation, again with the understanding they will do another inspection at the next outage.

MR. REYES: This is the best data we're going to have on eddy current testing on this application, so everybody is looking at it very closely.

DR. BONACA: The other plants out there that find cracks, they're not doing this stress relief operation, they're not being committed to inspect every cycle and so on, so we will see. But you're telling me that the inspection techniques are being improved.

MR. REYES: Yeah, specifically for the known causes or contributing causes at Summer like the articulated sled and the position of the sensor, being sensitive about field welds that had a lot of grinding, a lot of rework, and things like that.

That intelligence, I think Summer brought that to the light, and we've seen that on the field work.

MR. LEITCH: Would you think that the mechanical stress improvement would destroy some evidence of the crack growth rate? Would they still be able to look at these cracks and get meaningful crack growth data with the mechanical stress improvement?

MR. REYES: I'll ask Billy. Billy, do you have a -- Do you understand the question?

MR. CROWLEY: We should arrest any crack growth, but I guess as we continue to inspect these welds in the future we will find out. If the mechanical stress improvement does what you expect, you should stop the growth.

DR. SHACK: In fact, in theory you should be able to see it easier because it should blunt the crack which means your chances of getting a crack tip reflection are actually improved. That's the theory at any rate.

MR. LESSER: Let me move on to Bulletin 2001-01, control rod drive mechanism vessel penetration, cracking and temporary instruction status.

We have been doing the temporary instruction which is gathering data and inspecting licensee activities as they implement this bulletin, the bulletin inspections.

It is being performed by the resident inspectors and/or regional experts in nondestructive examinations. That means basically the licensee is going to do a visual, pretty much we'll have resident inspectors do the temporary instruction. If they're going to be using volumetric techniques we will have one of our DRS inspectors do the temporary instruction.

The current status, the Bin 1 plants, these were defined by the temporary instruction. Bin 1 were those plants that at the time of the bulletin had already had active cracking. Our only plant in Unit 2 was Oconee. All three Oconee units have shown thru-wall cracks, have penetrations. We have done the temporary instruction on Units 1 and 3, and Unit 2 we will do it this fall.

Bin 2, those were plants that were within five effective full power years of the reference plant, Oconee 3, and we have done the temporary instruction on both the North Anna and Surrey units.

North Anna 2 and Surrey 1 both had cracks that were repaired. Robinson, we will do the TI this fall.

MR. LEITCH: You said North Anna and Surrey both had cracks that were repaired?

MR. LESSER: Yes, North Anna 2 and Surrey 1.

MR. LEITCH: And the other units have been looked at, and no cracks found?

MR. LESSER: That's correct.

MR. LEITCH: And how many cracks were in the units that were repaired?

MR. REYES: While he's looking for that --

MR. LESSER: I've forgot the number.

MR. ROSEN: We have a special interest in that, because North Anna and Surrey are currently up for license renewal.

MR. REYES: Correct. But they have purchased reactor vessel heads, and they will be replaced in 2004. We have eight -- what I was going to tell you while Mark is looking for the numbers -- we have eight units that have announced head vessel replacements, the three Oconee, Crystal River, and the four -- the two Surrey and the two North Anna.

In fact, going back to our strategic work force planning, starting in 2003 other than Davis Bessie will be the first region that's going to go into a very heavy schedule of spring-fall, spring-fall, spring-fall replacement of vessel heads.

Some of those include cuts into containment, containment will be cut. In fact, the top of the containment will be cut in some cases to get them in. So our engineering resources starting in '03 are going to be very taxed.

MR. ROSEN: It seems to me this is not a regional problem.

MR. REYES: No, no.

MR. ROSEN: I mean that's a whole new ball game, cutting into containments and things like that, so it's not just head replacement, and you need to get some input from headquarters.

MR. REYES: We've done it before. The steam generator replacement at Surrey, Turkey Point, and Robinson required containment cuts.

MR. ROSEN: I don't mean to interrupt. I don't think one containment cut is not equal to another containment cut. Containment cuts, some cuts are a specialty art.

MR. REYES: Yeah, and we went through Surrey one before when they replaced the two generators, and so we'll have to go through all that again.

MR. ROSEN: To me it's more like original construction, and your expertise have to be -- how should I say -- not as vigorous as they once were.

MR. REYES: Correct. We are very fortunate that we have people like Billy Crowley and others who were in those days. And our intention, just so you now part of the strategic work force plan is every one of these activities will have an experienced inspector who's done it before, and they are going to be accompanied by a designated person who will have had upon designated to have been through concrete school and all those things, and will be the designated person to take this --

MR. ROSEN: Rebar.

MR. REYES: Yeah, rebar. So we have a very heavy period of work coming on because of all the announced reactor vessel heads replacements.

MR. LESSER: I think to answer your question, North Anna 2 had three thru-wall leaks, and Surrey 1 had two thru-wall leaks.

DR. SHACK: Is Oconee the only one with leaks that's been reinspected?

MR. LESSER: Yes.

DR. SHACK: When's the next reinspection coming up for some of these that had leaks?

MR. REYES: North Anna 1 is coming into a full outage on September, and --

DR. SHACK: Because it was rather surprising you didn't have more leaks.

MR. REYES: In Region II we don't have anybody in that situation, but there may be some in other regions.

There was not leaks every place. In these eight I talked to you about they basically decided, it's a business model decision, the time out of service for the station and the cost of doing the NDE and the repairs both from money and exposure. In a business model the decision is quick, you spend $10 million to buy a new one and get it over with, and that's why I think you're going to see more and more.

DR. BONACA: Most of the cracks were axial; right?

The ones you discussed.

MR. REYES: You mean the ones that we found leaking?

DR. BONACA: Yeah.

MR. LESSER: Some of them have been circumference, and some of them have been axial. Most of them are axial.

MR. REYES: One or two of them.

MR. ROSEN: Tell me a little bit about what you saw. Was this popcorn boric acid deposits?

MR. LESSER: Yes.

MR. ROSEN: In every case, or thru-wall cracks? Was it identified from the boric acid deposits, and later confirmed by volumetric inspection?

MR. REYES: I'm looking at Billy. The ones that I'm aware of, the pictures that I've seen, you have a little bit of boric acid deposit, you can describe it as popcorn, and we can get you some of the pictures.

And then the question is where did that come from, and then you go and do the NDE from inside the vessel head and confirm either axial or circumferential, depending.

I think we only had one circumferential, and North Anna had two. I think that's correct.

MR. LESSER: You know, when they visually look at the head with either remote optics or something you can see boric acid crystal around the nozzle, around the four-inch nozzle, if that has been squeezed up from the annulus from the bottom of the vessel.

Now, part of the bulletin is they have to be able to show that in fact there's enough room in this interference bit that will move up and make itself known there. All the plants may not necessarily be able to show that, and if they can't show that then they can't call themselves -- they can't call that a qualified visual inspection. They have to -- if they're in a higher susceptibility category they would have go to in and do volumetric inspections.

MR. REYES: But the pictures are very telling. I mean you look at it and right away you know it's boric acid, popcorn kind of shape, and you right away know you have to go underneath.

MR. ROSEN: I believe -- and I'll ask the other side of the question -- if it doesn't show that do you know anything?

MR. REYES: No.

MR. ROSEN: It could still be going on?

MR. REYES: Yes, that's correct.

MR. ROSEN: It could be still cracked, certainly it could be -- not thru-wall, but the next question is could you have a thru-wall crack and it doesn't show at the surface?

I have examined that question several different ways in several different forums, and the answer I typically get is if you have a thru-wall crack it will show on the surface, and

I was wondering what you think.

MR. LESSER: Well, no, I don't believe that's the staff's position. I believe that you have to be able to also show analytically and with as-built dimensions that the interference, the nozzle though the head will in fact expand when you're heated up and there will be an annulus to allow that to travel.

There is some thought that, you know, that if it's too tight you may not see it bubble up there.

MR. REYES: I don't know what the answer is to the question, but I can tell you what the answer is to the problem: replace the head with different material, and that's what I am -- you know, as far as I can tell that's why you have eight vessel heads in Region II already lined up for replacement. I'm just giving you --

MR. ROSEN: If I'm wearing your moccasins, Luis, I would be a little bit uncomfortable about a clean inspection because it it's clear to me that that crack would not be damaging the head without showing boric acid deposits on the surface.

MR. REYES: Correct.

MR. ROSEN: I have never been fully apprised of that.

MR. REYES: You have to use several things that get you to the comfort factor. One is the equation that gets you to is it a likely situation to be occurring or not, and we learned -- and I'm no expert on this -- we learned from the French that we may have to modify our equations a little bit, but I agree with you. But I think if you do a visual and you don't have any more gaps in it, then by analytical you don't think it's likely either I think you have reason to believe it's okay.

Now, we have a lot of plants that are not in that category, and that's why I think you'll see the replacement of the vessel heads, and as far as I'm concerned that's the only answer.

I think you're going to see a lot of replacement vessel heads coming up. Once the first ten or twelve get it pretty much done and all the lessons learned are there, I think you're going to see more utilities going in that direction.

I have several executives who have told me that they're going in that direction, they're just trying to figure the timing.

DR. BONACA: Those are only the ones in the highest susceptibility category, so the intermediate they would not jump to that conclusion yet. I think with the questions that Steve is pursuing I think that's very significant. One could say why not have an automatic inspection of all those intermediate class to get a sense of where you are unless the decision is made to replace the head, which I don't think is going to be made for most of us.

MR. LESSER: I think you're right, because the Bin 4 plants for example, some of the projections show -- corrosion is a function of time and temperature, and if they have a lower head temperature the likelihood of corrosion and the corrosion rate is going to be much smaller, and some of the models are showing it may be many, many, many years past their license where they would start to see this, so it will be the ones that are susceptible first.

MR. REYES: The ones in the top tier are going to go to the bottom because they're going to put new vessel heads with new material, and then what used to be in the middle is now your top concern as a regulator.

DR. BONACA: I mean it seems to me is the opposite situation. The burden is to demonstrate that there is a concern with the boiler head.

MR. ROSEN: I asked of the MRP, Don Refus, and he showed me a chart applying the temperature, compliance, and various things, and he told us how all these points seemed to be consistent with the model, the time and temperature model, and I asked him what would not be consistent with time and temperature, and he pointed to a plant, a low-temperature plant, or a low-temperature region on the graph and said if we get a crack in one of those we'll go back to square one in designing the system. So I think that's what we will be looking for.

And you're right, the picture will change as people change heads, but it may come out that those hot level, most susceptible plants will be rather not susceptible. Even though they are the most susceptible in their remaining BWI they will be rather unsusceptible because of their temperatures.

So then you can go a little bit relaxed except if you get aa leak in one of those. That's a telltale that says something is wrong with the simple model, and there are more factors involved here.

MR. LEITCH: Was there any commonality in heat numbers of the nozzles having cracks in North Anna and Surrey?

MR. LESSER: I don't have that information. I think there's some site --

MR. REYES: I know a little bit about it, the B&W units. I was told, and I cannot confirm this, that they were looking at the tube itself, the material for Crystal River, Oconee, and Davis Bessie to see if there was a heat of material was involved in it, and I haven't heard the answer whether there was.

MR. LEITCH: And I think we heard, if I recall correctly, that the ones that were cracked at Davis Bessie were from the same piece that was common strata, but I don't have that data.

MR. LESSER: Some of the open issues still with the bulletin, again we have a few plants that we're going to complete the temporary instruction on this fall, and we'll be all done with that, there are some plants that have not received a closure letter from the NRR, NRR is continuing to review that.

And also how we disposition and document the enforcement of thru-wall cracks, still we're working through that to be consistent throughout the region.

And also from a significance determination the first of set of cracks that occurred at Oconee, we considered that we used enforcement discretion, the second set of cracks we would consider those, but that's still predecision.

And I think we talked, we were talking about vessel head replacements. Oconee is starting with the spring of 2003 they're going to replace Unit 3; Crystal River in the fall of '03. I didn't put North Anna up there, but North Anna and Surrey we've got some indications that they're planning to replace their heads.

We are planning to go -- the Oconee heads are currently, they were fabricated in Japan, they're currently at the B&W facility in Canada. A couple of my staff is planning on a visit of that facility in July along with NRR to observe basically some of the fabrication of the heads.

With that that concludes my presentation. Are there any other questions or discussion?

MR. ROSEN: Is the head fabrication in your understanding going to be very much like what we've got now? I mean is it a straight fit on those nozzles?

MR. LESSER: I believe so. They would be using Alloy 690.

MR. ROSEN: Are the fabrication techniques still the same?

MR. LESSER: I don't know a lot about it, to tell you the truth. I'm making the assumption it is.

MR. ROSEN: Clearly if that's what we're doing we want to know a lot more about the dimensional fit.

DR. SHACK: Of course they will do a baseline inspection this time.

MR. LESSER: Oh, yeah.

DR. SHACK: We will get a pre-service inspection.

MR. LESSER: Okay. Well, thank you very much. Yes.

MR. ROSEN: To come back for a different thing, on the boric acid inspection programs, how sensitive do you think your licensees are about removing -- you know, did they leave boric acid on susceptible materials? Is that -- You know, they did that at Oconee, I mean at Davis Bessie. Do you know that that's going on in your plants that somewhere they're leaving boric acid on materials because they feel it's harmless and they don't want to spend the command RIMS to get it off?

MR. LESSER: You know, that's a good question. I don't think we've looked before Davis Bessie obviously. I think there's a big difference before and after Davis Bessie would be my feeling talking to people, but I don't think it's something that people -- we don't know if they looked that hard at it, and we were relying on their 2002-01 bulletin responses and then what we do with that.

DR. SHACK: Do you have any feeling for how they react to tech spec leakage?

MR. LESSER: Yes.

DR. SHACK: Everybody has a one-GPM limit, but what do they really do, you know, when do they really start to worry about the leakage?

MR. LESSER: That's a good question. >From my experience, and I think I would probably say generally most of the plants monitor it and have a baseline unidentified leakage that they have seen for a long time, and when it goes up there's a bit of a spike well below one GPM, even well below a half to a quarter GPM at some point they say, hey, something has changed in here, let's go in and look. They may send people to go in and look-see if they can find something.

I think -- you know, my feeling is that most of them are pretty sensitive towards that because they know it's only going to get worse once it starts coming up.

MR. ROSEN: Mark, isn't it your experience or the experience of your inspectors that that's not the first indication they have of a leak, that the first indication is typical radiation monitoring alarms from particulate or other sensors in the containment?

MR. LESSER: No, I don't know that they're that sensitive, the rad monitors are that sensitive to pick up leaks at low levels about a tenth, or a change in a tenth of a GPM.

My experience is that they pick it up, they see something when they do their three-day unidentified leakage calculation is their first sign that something has changed.

DR. SHACK: When French went through, they wanted to do leakage monitoring on the heads they built a can over it so they could contain it and then sniff it, so obviously you're sort of pushing the limits at the kind of leakage levels you're interested in.

MR. ROSEN: Especially plants that don't have fuel leakage problems.

MR. LESSER: That's right. That's a big input into whether the rad monitors will pick it up, absolutely.

Okay. Thank you very much.

MR. ROSEN: I think that's when our break was scheduled. What do you think?

MR. CHRISTIANSON: We were regularly scheduled for a break from 10:00 to 10:15. If you would like to have a 15-minute break we can reconvene at 25 after.

MR. ROSEN: Yeah, I think that's a good idea. So we're on break until 25 after ten.

[A brief recess.]

MR. CHRISTIANSON: The next presentation is Plant Operating Experience, Loren Plisco, Director, Division of Reactor Projects.

MR. PLISCO: Good morning.

What I would like to do is I was going to give an overview of plant operating experience in Region II really from an ROP perspective.

I'll give an overview of plant performance showing the action matrix, and a summery of which cross-performance indicator thresholds we think here in Region II, and a summary of our nongreen findings that we've had through the first two inspection cycles.

And then I'm going to ask individual branch chiefs, they're going to come up and talk about some specific -- and I wasn't going to cover them all, but I picked out some specific findings and PI issues that have come up that we have run through the process, and they'll talk a little bit about what the technical issue was and how we handled it within the process.

What I was trying to do is give you an idea of the kinds of things that have bubbled up out of the program that we've had to deal with in the process, the kind of technical issues and the kind of performance indicators.

MS. WESTON: Loren, if I may, do you have in your packages the printouts for those issues?

MR. ROSEN: Also, Loren, would you also indicate how the regions are doing in terms of not generating false positives in terms of scores on, you know, getting a red when it really looked to be a yellow. Have there been any Region II cases where you said it was yellow and after the regulatory conference it came out lesser than that, or greater than that?

MR. PLISCO: We have had some. They either stayed the same or they were lesser. None of them went up.

MR. ROSEN: I'm interested in those not because it changed so much, but because clearly there was some lack of understanding of the actual circumstance that got rectified in the process, and that's inefficient, and it's something we need to work -- I don't think you'll ever get a hundred percent on it, but you need to work to minimize that.

MR. PLISCO: Well, two of them specifically we're going to talk about. I think Kerry is going to talk about both of them. We had one in security which is another issue.

MR. ROSEN: Well, those are flags for us about some process issues that -- you know, nothing against the people, but it's the process issues I'm after.

MR. PLISCO: And they weren't issues of new information, they were really issues of assumptions, or models that were used, and then in the discussion with the licensee there was agreement to either use a different model, or approach in the modeling.

MR. ROSEN: And the lessons-learned process was then generated which puts that in the front end so the next time that kind of thing comes up you don't end up in that same place.

MR. REYES: We'll show you one example particularly.

MR. PLISCO: And Kerry actually has two he's going to talk about. One is a Surrey diesel issue which the SDP analysis came out higher, and after the reg conference it ended up a little way. And then the Summer-Watts Bar issues, the same thing is true. And there's a different story on each one of those and why that ended up --

MR. ROSEN: I'm interested in learning provision for the staff.

MR. PLISCO: The other point I wanted to make is that when I show these summaries the good news and bad news about the rank oversight process is it's more real time than the When you look on the Web site, and you look at summaries of where the plants are that's as of a certain time frame, and if you look a month later, you know, on a day-to-day basis it changes, which is good because then we have some current information rather than SOP you look back 18 months when you look at the most recent SOP it was really whole information, real time.

MR. ROSEN: You're giving a plant that's really solved a lot of problems a very bad report.

MR. REYES: Two years later you'll see it's --

MR. ROSEN: Two years later, right.

MR. PLISCO: But it has caused a few communication difficulties, since it is a moving target and there's a lot of information out there, and what's on the Web site is typically updated quarterly where the plants are action measures, where it really can change daily if a new finding comes up, or a new finding it changes their status, which has been a new communication issue we've had to deal with.

And I'll show you an example on the first slide. This is a summary of where we are nationwide. This was as of March 31st, the first quarter, and that's what's currently on the NRC's Web site.

In Region II you can see we don't have any plants that are in the degraded cornerstone or above.

MR. ROSEN: This says you need to be in an even-numbered region.

MR. PLISCO: And I was going to walk through that this is a snapshot. We have actually had two plants that have been in the degraded cornerstone; they're out of it now, and you're going to hear some of the discussion when the branch chiefs talk about that.

Oconee 1 has been degraded cornerstone and they are currently out; Farley 2 was degraded cornerstone and they're currently out. So as I said, it's a moving target. If you look back historically we have had plants in these categories.

And the same for regulatory response. Right now we have three plants, that's Oconee 1 and Surrey 1 and 2, and the branch chiefs are going to talk about the specifics of the reasons why they're in there.

But we have had about eleven plants that have been in and out of that category through the first two inspection cycles.

DR. POWERS: You have no idea how much more enthusiastic I am about your headings, your columns than colors.

MR. PLISCO: And these are what we try to use in the public meetings when we're trying to communicate to get away from the colors.

DR. POWERS: Because those communicate, whereas your colors don't. This tells you what you're doing, and the colors just don't.

MR. PLISCO: Any questions on this overview of where we are and where the rest of the regions are?

MR. LEITCH: This is as of the end of March?

MR. PLISCO: March 31st, that quarter. And it's updated -- we update the matrix that's on the Web site at the end of the quarter.

MR. LEITCH: The fact that Davis Bessie is not in the unacceptable performance column --

MR. PLISCO: All that means is it hasn't been resolved yet.

MR. LEITCH: That's still in the pipeline.

MR. PLISCO: The final finding hasn't been issued yet as of March 31st is what it means.

MR. LEITCH: I think that's one of the issues, though, that we were talking about that were related to public comments. If you showed the public that slide and said this is as of March 31st I think they would expect to see one in the unacceptable performance column, or maybe that's not where it's going to wind up, but it's unacceptable to me, though.

MR. RISEN: I think they're through with drawing conclusions on --

MR. LEITCH: They're not, that's the point. What I'm saying is if you showed this in a public forum it doesn't exactly instill public confidence when you see there's no unacceptable performance.

MR. PLISCO: And that was the point I was trying to make, it's a snapshot at the end of the quarter, and you really have to look at other information to find out where you really are. And we have an example we're going to cover today in Region II. We actually have plant in the degraded cornerstone as of last week. Harris went into degraded cornerstone. We issued a white finding last Thursday that gave them two mitigating system cornerstones which puts them in the degraded cornerstone, and George is going to talk about the technical issues that put them there, but in fact this just happened last Thursday. So it says zero, but we have one now.

MR. REYES: In two weeks, June 30th when the next quarter rolls over it will show that.

MR. PLISCO: It will show that, yeah, sure.

This is a summary for the Region II plans where licensees have crossed the PI thresholds during the first two assessment cycles.

MR. ROSEN: That's impenetrable for me.

MR. PLISCO: I was going to explain that.

The column on the left are the cornerstones. It's initiating events, mitigating systems, barriers, emergency preparedness, radiological protection, occupational radiological protection, public, and physical protection, the seven cornerstones. I was trying to get it all on one slide. I'm guilty.

MR. ROSEN: It's just a little to short for me.

MR. PLISCO: I'm guilty.

And as you can see, most of our activity has been in mitigating systems. That's where a lot of our inspection effort is focused.

In the PIs there were a lot issues especially early on with interpreting how to do that performance indicator, how they collect the data, what counted and what didn't count, and there's actually ongoing work that the program office has in place to try to address some of the problems that were in that performance indicator.

But as you can see in the first cycle we had five crossed thresholds in that performance indicator. We're going to talk about some of those when the branch chiefs talk about the specific issues, they will give you some examples of the kinds of things that cross thresholds and why they cross the thresholds.

One I wasn't going to speak too much about when the branch chiefs talk is in the barrier. We did have three cases, you can see two in the first cycle and one in the second. Those were RCS leakage issues, and that's been interesting from a public confidence-public communication issue. That PI threshold, the white/green threshold is only 50 percent of the tech spec limit, so you can have a plan as a white issue that they can continue to run, but the problems are still there. That's been a little bit of a communications issue.

We respond, we do extra inspections, and they still haven't even reached the tech spec. But that was one of the PIs that had a lot of debate early on, should we have a performance indicator. That was a discussion of making sure we had something that showed the public where our plants were as far as what their system leakage was, and that was the threshold that was picked.

And that green-white threshold was really intended to be I think a 95 percent outlier threshold, and that's why they picked the 50 percent. But we do have problems in risk communication with the public on why the agency is responding when they haven't even reached the tech spec.

MR. ROSEN: Remind me, is that a 50 percent of unidentified or identified?

MR. PLISCO: It's identified, 50 percent of identified leakage.

In a couple cases there was valve leakage, a packing leak, or a pressure seal type leak that exceeded the 50 percent of the tech spec, and that drove that into the white threshold.

I also want to mention since January 1st we haven't had any new, this is all we've had since March, two inspection cycles and the current one that we started January 1st.

The next, this is inspection findings, the nine green findings that have been issued during the first two assessment cycles, and again you can see most of our activity is in mitigating systems.

We're going to talk about all the specific issues that are listed here, the six mitigating systems issues, and the one physical protection issue. That was a Farley issue that Steve is going to talk about.

And as I mentioned, we've had a one new finding, that was the issue at Harris, and we'll talk about the technical issues related to that. It was a foreign material issue at Harris, and that was a white finding in mitigating systems. It was just last week we issued that.

MS. WESTON: Let me ask you a question. The first quarter 2002 had a yellow; there were none in this region, but you're showing the end of the year, not first quarter 2002. Any particular reason?

MR. PLISCO: Well, what we're trying to depict on here is completed cycles. The January one just started. I mean it will go through December. And I mentioned what has changed the first couple months in the first quarter, but I didn't show it on here because it really had only been three weeks.

MR. REYES: If you see the dates at the top, we decided, the agency decided to change what we call the cycle of assessment to end-of-year, end of calendar year, so the headings are different because we as an agency shifted to the year calendar.

MR. PLISCO: This year is going to be a full calendar year inspection cycle. We did that to sort of balance the workload in regions of the assessment cycle, to get out of the fiscal year because our workload in the regions when we did the assessments at the end of the year was laying on top of the end of the budget year, and appraisals, and everything else, and we shifted to a calendar year cycle for the inspection program.

MR. ROSEN: Now I understand what you're doing here.

My comment is really about tell me about the ones that shifted from yellow to white, really about the inspection part.

MR. REYES: Those are the examples we have.

MR. PLISCO: We'll talk about some of those.

Any questions from an overview standpoint? The branch chiefs will talk about some of the specific finding issues.

MR. ROSEN: You know, I do have an overview comment. Let's just go back one slide. I'm a little bit slower than you are.

Just looking at the pattern of findings of mitigating systems, not in the other place --

MR. REYES: You mean why? Is that the question? Why?

MR. ROSEN: No. I don't even know how to formulate the question. It just seems so narrow.

MR. REYES: We have taken a hard look at that. If you get another region you'll see a different spread. For example, in Region IV they've been having a lot of emergency preparedness kind of findings, and if you do that table for Region IV you'll see yellows and whatnot in NEP.

We have taken a look at our program, and the program office comes and takes a look when there's a difference in terms of the population or findings from the regions to try to see is there something that's being told here, and we haven't been able to correlate it either, so if you have an answer we'll work on it because we think it's hard to make some correlations in some of the other areas, but we don't have an answer why one region will have a different spread than another region.

MR. PLISCO: And we have findings of other regions, but none that have crossed the threshold.

MR. ROSEN: Well, clearly mitigating symptoms, that's the readiness of the plant to deal with transient actions. That's really important.

DR. POWERS: It's also the area that you would hope that the NRC inspectors are focusing most of their attention on.

MR. ROSEN: True. And why is his region so good and all the other places have only one finding.

DR. POWERS: Well, again, you don't want to get too excited about a small sample.

MR. ROSEN: True. All I'm expressing is my --

MR. REYES: We have looked at --

DR. POWERS: It seems to me much more impressive to me actually as being the fact that we actually get findings in the colors other than green out of the system at about the rate that we kind of anticipated we would get them the system was set up. I think that's the real take-home lesson at this stage in the experience with it, because experience is just too short to start drawing patterns and conclusions.

MR. REYES: To give you one thing that my bosses have done, and they have met with INPO, the senior managers meeting between NRC and INPO, and they have asked INPO to take their plants, group them geographically like the regions, and look at the rankings that they give them, INPO 1s, 2s, 3s, and 4s.

There is a correlation, there is a general correlation. We at the agency are trying to make sure that in fact we're implementing all the programs the right way, and we have exchanged with the other regions to do inspections to try to if we're doing things differently and all that, and --

MR. ROSEN: I think it's the right thing to do, and I'm trying to sit here and say now suppose that you came back with no correlation how would you react to it, and are we being overly confident when we see there's a correlation.

MR. REYES: Right. And it just --

MR. ROSEN: And it's a small sample.

MR. REYES: But I'm just trying to note we have asked the same question in trying to find out other ways to make sure that we are --

MR. ROSEN: I mean I think you have to do that, I think it's unavoidable, but I don't think I would expect anything to come out of it until you have like five or six years of experience, and especially at first when you get a big perturbation you learning, licensees learning, everybody learning, definitions kind of floating a little bit, things like that.

MR. REYES: I'll give you an example. There's a randomness on the barrier, those three -- on the barriers is the PI what I'm thinking about -- it basically was equipment that started leaking, and for a while we had three units, three different components and they just started leaking, and the plant eventually shut down and replaced the whole -- there doesn't seem to be a relationship there. We probably don't see any for a while, and then we have three.

MR. ROSEN: I mean that's exactly what we're trying to do is get some indication. The telling thing is if you could in doing the root cause analysis you found that there was something deficient in their corrective action program that was leading to this. If you don't, then you say, well, fair enough, and then it eventually works its way out of the rolling average and whatnot.

MR. PLISCO: And we did find that in one case. It was a -- one of the rack system PI hits was North Anna, they had a rack and system and system bypass valve packing leak.

I think when our inspectors went back and looked at it they didn't have a program to replace the packing.

MR. REYES: That was a real problem.

MR. PLISCO: It had been in there fifteen years or something. That's what the problem was.

DR. POWERS: Yeah, that's what you wanted to do. I mean it works, score one for the -- take a structuralist view, Steve. Quit taking the rationalist view. This is a structuralist program.

MR. ROSEN: I am a rationalist with structural tendencies; you are a structuralist with rational tendencies.

[Laughter.]

MR. REYES: I just wanted you to know that we raised the same question, the agency senior management raises the same questions all the time making sure that we're not missing something.

MR. ROSEN: Yeah, I think you need to pass swinderize [?] and look at the patterns, but not draw too much from it right about now.

MR. PLISCO: Some people would also say, especially for the inspector findings, if you laid on top of that how many hours were spent in each of those categories the bulk is in mitigating systems, so some people would say that's where you spend your hours, that's where you're going to define the issues.

DR. POWERS: And where thou looks thou will find.

DR. LARKINS: The more you compare DIE for mitigating systems, how does that rack up?

MR. PLISCO: I don't know the percentage, but we have some inspectors here and I think they can tell you most of the areas that they look at is in mitigating systems, when we look at maintenance and operation --

MR. REYES: The real significance is there, so it takes you there.

MR. PLISCO: Steve.

MR. CAHILL: My name is Steve Cahill, I'm a branch chief over the Southern Company plants. I took over that branch right before even the ROP, so I have been with them all through this cycle.

It started out well when we entered the ROP Farley had all green performance indicators and we were in the licensee response band, but very quickly just a couple weeks into it we had an issue come up, and that was their first status for the PIs, it was the first quarter of the calendar year with data they submitted at the end of April.

They wound up having a white performance indicator that affected both units. It was on emergency AC power on availability, and it crossed the white threshold.

DR. LARKINS: Excuse me. Both units where?

MR. CAHILL: Everything I'm talking about it just Farley.

That's in the mitigating systems cornerstone, and as the slide says the cause of it going across the line was fault exposure hours. They were doing some 18-month surveillance as it failed, and it was a long-duration surveillance, and so the fault exposure hours at that time were T over 2, and nine months at a time those added up very quickly.

We wind up for our process we told them we were coming in and do a supplemental, and we had our resident inspectors do our supplemental inspection 95001 which basically is just verifying their root cause, and they come up with the appropriate corrective actions.

We looked into that and concluded they adequately addressed that. And we also had a regulatory performance meeting with them for the first white in the regulatory performance column. It was just a meeting with myself and the plant manager.

The PI returned to green about a year later, so that in and of itself was not that significant, but when we go on to the next one very shortly after that -- and this was actually something Luis took a lot of pride in -- in the next period, the first period, basically the second quarter of calendar year 2000 Farley recognized that they had a lot of issues going on with all the speed work, and in this case the PIs called heat removal, and they had had some surveillance failures, they were having some fault exposure hours they already knew were adding into their PI calculation, and they had a performance problem that lingered for a while.

Basically they knew beforehand that their data submittal was going to cross that white threshold. And this is data they were not supposed to submit until July, so we engaged early on this. They basically admitted that it had crossed the threshold, and we initiated our process.

This also -- this only affected Unit 2, but it also is a mitigating systems cornerstone, so knowing that the white PI would be in that mitigating systems cornerstone two white PIs constitutes a degraded cornerstone.

The root causes of this were also pretty much similar. We went and -- we started out doing -- there's a lot of comment themes, preventive maintenance and maintenance rule limitations, so we started out doing our supplemental inspection 95002 on this. Again, we were letting the residents do it.

And the difference between the first supplemental, the 01 we did versus the 02 was it looks at their root cause and their corrective actions, but it takes a broader scope of it and also looks at an extending condition, how broad is this problem.

And when the residents finished that phase of the inspection they came up with a couple of common themes in the maintenance rule limitation.

And so we wound up doing this inspection in two parts, the proposed and actually implemented a second part of the inspection with a DRS, division of reactor safety specialist going in and looking at their maintenance rule implementation. So we actually show two separate inspection reports for this one inspection.

Again we concluded that Farley's performance in addressed the root causes and developing corrective action was acceptable.

Also in the course of this after the residents had concluded their portion of the inspection, but before the specialists came in we held for our action matrix a regulatory performance meeting, and Loren actually chaired that. It was a higher level when the action matrix was the integrated cornerstone.

This was a public meeting where we basically initiated dialogue with Farley's plant management on what the issues were.

And after we completed those supplemental inspections and did our performance meeting that completed our actions for the integrated cornerstone and the action matrix, and that PI also returned to green in the first quarter of calendar year 2001.

In the fall of 2000 we had another PI that crossed the threshold. This was the initiating events cornerstone that was the Unit 1 on the plant power changes PI, so the fact that it was in a different cornerstone I think interacts with the other one, so it was basically a single white PI in isolation, so we went in and did the same IP that we did the first time around which is our IP 95001.

The cause of this PI crossing the threshold -- and this is another one that they knew they were heading this direction and initiated dialogue with us, they were being very open and up front -- they had a lot of cooling tower problems. Those aren't something that we would normally focus much inspection resources on, and Farley had not focused a lot of their resources in maintaining them, so they actually had portions of their cooling tower collapse, and they wound up taking six unplanned power changes in this year period the PI calculates, and four of those were directly due to the cooling towers.

And their obvious corrective action plan out of that was they're doing a wholesale cooling tower replacement. They have not implemented that. They did short-term repairs, but they will be replacing their cooling towers next year.

MR. PLISCO: They're just the old wooden style, just collapsing.

MR. ROSEN: How old are they now?

MR. CAHILL: They're original.

MR. REYES: Yeah, 30-some-odd years. These are low profile mechanical drive cooling towers, and their sides are made out of wood, and wood and water for 25 years gets you into trouble.

MR. CAHILL: This was a fairly easily-understood issue, so we elected to have the resident do the supplemental inspection.

MR. REYES: They knew they needed to do the work, but they delayed it, and they made some assumptions, and it didn't turn out that way.

MR. PLISCO: But again I think this is a success of the ROP. This is an area where we may have handled it differently in the old program. You know, cooling towers, BOP, we really wouldn't have said much. But now with the impact of looking more at risk, and the power changes, and transients they had to do something to fix it.

MR. LEITCH: Interesting you bring it up. We heard yesterday that Watts Bar took a scram several months ago due to a cooling tower fill problem. It's kind of the same type situation.

MR. CAHILL: One issue that came up a little with this point, Farley was very sensitive that they had crossed the threshold, and obviously wanted to get back to green, so they were preplanning several down powers in the future for any future cooling tower problems, and they were trying to make it so that they wouldn't have to take future PI hits.

Basically once they crossed the white threshold they started looking very closely at the criteria and making sure they understood them, and could do everything possible to make sure they didn't have to take future hits. So there was a lot of dialogue between us on letting things just fall where they may versus the fresh views of managing the PIs.

MR. ROSEN: When the licensees now really start thinking about these PIs and start managing their way around the PIs to me what I see is not -- this is not managing the indicators; this is really managing the risk because they end up doing things that result in no unplanned power changes, or fewer of them, and that is not just managing indicators. That's managing the real stuff. That's what I like to call chicken, not feathers. It matters.

I think the behaviors you see out of this system are the ones we intended to promote.

MR. REYES: I think that the examples we're showing you, and we share the view, is that the ROP has really highlighted issues that perhaps may not have been highlighted before, but more than that, it has changed their behaviors, or reinforced certain behaviors, and you see the plants coming out of the white PIs and white findings and go to the green, after doing a review and changing the way they do business. So it's been successful.

DR. POWERS: Surely you're not suggesting, Steve, that we're managing the culture of the plant.

MR. ROSEN: They're managing their behavior, and behavior is a part of culture.

MR. PLISCO: I do have to say we did have some discussion with Farley. What they did after they had some of these cooling tower cracks is their original procedure had been to do down powers of more than 20 percent, and after they hit the threshold they changed their procedure to do 19 percent power reduction.

MR. ROSEN: That sounds a lot more like feathers than it does chicken.

[Laughter.]

MR. REYES: But eventually -- you know, that was short-term management controlling the PI, but eventually they realized they had to move up the whole project on fixing the cooling tower, and they actually did some temporary repairs that solved the short-term problem awaiting for the material to do the full scope.

MR. ROSEN: I would suspect that at least the staff have enough sensitivity and sophistication to be able to detect the difference between feathers and chicken, and to make your views known when you think that they're fooling around with the feathers too much.

MR. REYES: We do.

MR. CAHILL: And the residents are invaluable in that. They're the ones that are seeing this firsthand.

MR. REYES: Because they actually sit down on the meetings and decide where the discussions are going on, and you know right away.

MR. ROSEN: And it gets painfully obvious to the licensee that that's not what you intended, that's not the behaviors you were intending to promote, so they don't wan to be in that circumstance.

MR. REYES: No, they don't.

MR. CAHILL: This PI quickly returned to green in the third quarter of 2000 as some of those first down powers fell off the rolling one-year window that they look at.

So at the end of the calendar year, or actually the first quarter of 2001 none of these PIs were in the white band, they were all in the green which -- the reason I'm mentioning that is because the next issue we had was a white finding in the physical protection cornerstone.

This was actually started in July of 2000, we did an OSRE about it, and preliminarily we said three out of four the drills that they had failed, but at that point we had a lot of issues with the protection SDP, and basically that SDP was, or the significance determination process was in limbo, and we were really hamstrung in moving forward, so these were put in abeyance for a while while the SDP got finalized, and it wasn't until the spring of 2001 that we really had the SDP finalized so we could move forward on this.

MR. MALLETT: Steve, you might clarify, move forward on what we did with the finding. They proceeded to fix the issue.

MR. CAHILL: The performance issues that came up, they took immediate corrective actions on those.

The findings were apparent violations, they were just basically held open until the spring of 2001.

Our first look at that was in June we sent them a choice letter saying that this looked like a potential yellow finding.

MR. ROSEN: You called that a what?

MR. CAHILL: A potential yellow finding.

MR. ROSEN: You said a choice letter?

MR. CAHILL: We sent a choice letter. It's basically a --

MR. ROSEN: I know. I just hadn't heard that term. You can choose to have a regulatory conference, or you can choose not to have one.

MR. REYES: You're right. That's what we call it, it's a choice.

MR. CAHILL: They obviously elected to come in in July of 2000 when we had an enforcement conference.

MR. ROSEN: Enforcement conference, or was it a regulatory conference?

MR. CAHILL: It was both.

MR. ROSEN: Isn't there a difference between a regulatory conference and an enforcement conference?

MR. REYES: This is in the transition, so we had to have two kinds of meetings. But today we would have a regulatory conference.

MR. ROSEN: Okay.

MR. REYES: In those days we were mopping up old issues and new issues, so we had both.

MR. CAHILL: Basically at the time of the choice letter Farley realized that this yellow would overlap, would backdate to July 2000 when the OSRE was because that was on a timely finding, and that's why it would show up in our action issues, and that would overlap with our degraded cornerstone that I talked about earlier, performance indicators. So even though it was a year later we were processing this the backdating of that thing to the time of the finding would overlap, and that could constitute multiple degraded cornerstones.

Farley's efforts to work on this physical protection finding obviously escalated accordingly, but there were multiple degraded cornerstones that would have been the same type of inspection that Cooper is getting now and that Indian Point has gotten.

So anyway, we had this enforcement conference in July, and a lot of issues came up, but the drills -- basically two of drills were invalidated from us processing the SDP. One for some artificialities, and one was basically we did not comply with the design basis threat on the way the drill was conducted, so it wasn't valid for the OSRE conduct guidelines we have now.

You asked before about ones that came out high. Our final decision which we issued in August was this was a white finding. A lot of that, the SDP for physical security is fairly subjective, you have to make programmatic assumptions to be able to take it from white to yellow, and without having that large a number of drill failures we couldn't use the language that was in the yellow finding SDP, so it was issued as a white.

Therefore, that unit of the cornerstone really did not interact with the degraded cornerstone we had before, it constituted a degraded cornerstone all of itself. Actually it was a white -- excuse me, a white finding on the physical protection cornerstone, so we did a supplemental inspection in November of 2001, and we had a regulatory performance meeting which again was a meeting between myself and the plant management in December of 2001. And that has closed our book.

So right now Farley is back in the licensee response column, and all their performance indicators are green.

MR. REYES: I think you're going to find out on the other examples that colors were changed as a result of the regulatory conference. A lot of the changes had to do more in the subjective areas of how the colors are defined, so we talked to the yellow security, and when we talk about another one I think you'll see that there are certain processes -- if it's a mitigating system it's straightforward, and then there's others that are not as precise, and I think you will see more color changes.

If you do your work up front well, you only should see changes on those that are more subjective.

MR. ROSEN: And as you get more experienced with this, and the licensees become more experienced in interaction with the resident I think before the finding is even written you can get the facts in line that have bearing on how you judge the matter at hand so that you can probably say, okay, now, these are the facts, this is what really happened, and you're both shaking your head yeah, that's what really happened. Now, given that, that fits over here, right? and you can say yeah, I think it does, and you can jointly agree having agreed on the facts that this is where it fits and it's a yellow, or it's a white, or it's a green.

So I think it's all a matter of learning how to use the system, and I'm very encouraged by what I see.

In fact, I think there's another use for it all that seems apparent to me and that you've thought of already is this concept of coming in and out of findings, in and out of white.

At the moment you're doing that, you see a finding of white, and you look up and down the column and across the matrix and see if there's anything else so you can put it in the right place on the action matrix.

But in retrospect as you build more and more of this record you can look back and see for a given plant it's been in and out of white a lot of times, you can do a calculation of what percentage of the time it's had the white, or two whites, or whatever, you can look back at the track record that even a plant that's doing a lot of that should be of some more concern than one that maybe had an isolated case, or one that's always coming in and out of white in the various areas you've got to start drawing some conclusions there.

MR. REYES: We do that.

MR. CAHILL: I forgot to mention when it was up there before, we had planned do to a follow-up OSRE after we issued the white finding in August 2001, we had an OSRE scheduled for September 20001. That got canceled for obvious reasons, it was scheduled the week of September 11th. We were going to do our supplemental, and the scope of that was going to be determined on the results of that OSRE, and since we didn't do the OSRE we went in and did a broad-scope supplemental inspection just to verify how they had addressed the performance issues associated with the white finding.

MR. LANDIS: My name is Kerry Landis, I'm the branch chief for Branch 5 which is the Virginia power plants and V.C. Summer Plant.

I'm going to shift my comments a little bit to address the focus that you identified of why the changing color, and also the lessons learned from that.

We had at V.C. Summer a fairly straightforward event where operators failed to follow surveillance, failed to open a discharge valve to the emergency feed water system, the turbine-driven emergency feedwater box feed water, and locked it in the closed position thinking that it was open, and the independent verifier came through and did not verify that the valve was open. Did verify that it was locked, of course.

So that condition existed for 48 days, and the NRC did a Phase 3 SDP calculation using the ask-human-error work sheet which is pretty much the static human error conditioners, and came up with a yellow, and we issued the letter, choice letter for that.

The licensee came in, and right before they came in we understood that they were going to use a more dynamic human error rate predictor model THERP, and we didn't have really the expertise to be able to go through that in detail prior to the regulatory conference.

We did listen to it, and subsequent to the conference we did take their full calculation, THERP calculation, had an independent review of that, and agreed with them that it did more accurately reflect the dynamic ability of operators to be able to recognize the condition and to recover emergency feed water.

That ended up lowering the probability almost in half, which dropped it right down into the white zone.

MR. REYES: And that's the point I was trying to make. If you calculated just for the out-of-service time for the turbine-driven auxiliary water pump you would have come into yellow, and all that made it change back to white was how do you model the recovery, how early it was corrected and have recovery, and I personally walked down this system and this valve.

We probably have half and half of the staff agreeing that we should give them as much credit as we did or not, but the point being is that you are going to get to a regulatory conference with a color on these subjective areas and these areas where you have to make an estimate, your best estimate of how quickly can they identify the parameter, how quickly they actually reach the component, find it, which is labeled good lighting, inaccessible and recoverable.

MR. ROSEN: Good lighting in the station blackout condition for this pump; right? Was this pump turbine driven off feed, it's intended for cases where you have no off-site power and no on-site power.

MR. REYES: This valve is --

MR. ROSEN: Because the lights are going to be out in this case, so you could have --

MR. REYES: I walked, I climbed, and I touched this valve, and it's not as easy, and I did it personally I know what you're talking about, I took my time and went down there.

But my only point is, and I'm not arguing if the model is right on recovery or not, is that you are going to get the situations where you get yellow, and when you model the recovery you may come down to white, gives them more credit than you originally did. So I'm not sure we'll ever get out of the situation where we go to a reg conference and we don't change the color.

MR. ROSEN: No, I don't think you will, but I think in this case the lesson learned might be that in a case like this you really ought to use THERP right out of the box, not use simplified model if you suspect that the operator's dynamic responses will change the result dramatically.

MR. REYES: I think we both learned, the licensee and us we both learned.

MR. LANDIS: What do we now, Walt? He did the analysis.

MR. ROGERS: Well, we don't just use the THERP right out of the box. We use whatever given the model that we're using to develop the risk impact problem, we will use that methodology.

The V.C. Summer case was an excellent case because it essentially established how we do business. We went in using the ASP. However, coming out there we said if we used the licensee's full-stroke model then we'll use the same methodology that they used that worked on modeling other operator actions, recovery actions which in their case is THERP. So we'll draw the THERP, we'll do that. We use the SPAR model as the model that we're using, then we would use the SPAR and the work sheets to develop, so now we have a level of consistency.

That's what V.C. Summer produced is our methodology that we would use to go into the regulatory conference.

MR. ROSEN: I'm not sure we're communicating just yet, and I think it's important that we do.

What I'm saying is that you have a circumstance like this where it's the outcome -- an important document like the color on it is going to depend on how well you model something like a human recovery action.

Then you ought to know that pretty early on, and you ought to say we can fill out the ASP work sheets, but it's not the right answer for this. We really ought to be -- And we'll do that, but we're not going to base -- we shouldn't base our determination on that, we should say after the determination to use ASP, but if you use a more accurate model or a model that takes into account both factors you get this answer, and then let you make the decision which one do you want to use.

I don't think you should be blind to that, you shouldn't be in any kind of rote mode. You should be using the best tools available is what I'm suggesting.

Do we not agree or --? I mean it's okay not to agree.

MR. ROGERS: I think you've got to look at what all you're using to draw your insight and apply the appropriate knowledge.

If you look at the two HEP work sheets it pretty much uses the same factors.

MR. ROSEN: The same performance shape.

MR. ROGERS: They have them, they may have them on a different set of weightings and how they're done, and when you -- I mean we knew going in that this would be the -- and this was our test case on the protocol that we would use from here on, and if we were to go to V.C. Summer and have another performance deficiency that we have to analyze and we're going to analyze the human recovery action we'll know where to start.

MR. REYES: And I think -- I understand your point, and what we have seen is we have seen more and more responses to the choice letter saying no, we agree with you, Regulator, it's white or whatever, and we don't think it will be fruitful to have the meeting because we share with them here's your calculation or assumptions on how we got to it, and we see more and more of that, and it's the up-front work -- I agree, is this the right thing to do.

MR. ROSEN: It seems to me it's the right thing to do is to do more work up front to get it right, and that's models that you can agree on, and rather than it's a false positive or a false negative.

MR. MALLETT: But regardless of what color you come out with, it's also important what we said earlier today is that we deal with the issue and get it fixed.

MR. ROSEN: Oh, yes.

MR. MALLETT: I don't want to give you the impression that we were waiting on that.

MR. ROSEN: No.

MR. CHRISTIANSON: Walt Rogers is one of our region's senior rep analysts.

MR. LANDIS: You really hit the lesson learned and captured both of these that I'll go into for the next event here also, but the lesson learned is any time you have variations in the application of the risk modeling we need to understand that it will either have the same risk model THERP or we're going to get into a varying condition on core damage probability calculation here at Surrey we need to do the same thing as the licensee, or at least understand the difference and what impact it has.

DR. SHACK: I certainly don't agree that you have to do the same thing as the licensee. I mean I think you have to understand what the licensee did and how the modeling assumptions affect the outcome, and then you make a decision.

I mean I would hate to see a procedure that said, okay, the licensee did it this way so we've got to do it this way.

MR. REYES: No, we don't, but we try to make sure that they understand how we did it, and we ask them how do you do it and what assumptions you use. It's important that we come up with an answer which is the right answer, and the dialogue is always helpful. I think you'll find out we do a lot of that up front.

I think somebody did a review of the different regions and the final determinations versus the preliminary, and we were closer than most.

DR. SHACK: Especially in something that's affected by human error modeling there is no right answer.

MR. REYES: That was my point.

MR. ROSEN: But in some models don't they take into account the safety factors quite as well as others, and things like operator stress and --

DR. SHACK: I think it's very important to understand that the outcome is very conditional on your understanding of human error probability without declaring that this model is -- you know, because we'll bring George here and we can -- How many days do you want to debate the issue?

MR. ROSEN: I want to find out what his problem is.

MR. PLISCO: Walt is very good at briefing us on -- I mean I think this case came, it was right on the line, it was right ont yellow/white line, and he told us ahead of time is is what's going to make the difference in the call on this.

And there's other cases where it doesn't matter, it's in the middle, and even if you argue about it it doesn't matter.

MR. REYES: This is a good point. Coming to this meeting, going through the meeting we knew exactly what the discussion was going to center on, and what the decision was based on, and so it was not -- we knew it could go either way.

MR. ROSEN: That's why you get the big bucks to make that decision.

MR. REYES: They do the heavy lifting, I get the credit for it, but Walt and the technical staff and managers did a very good job.

I knew before we entered the meeting exactly, Boss, this is why and this is the zone where we're going to have to make the agreement on. They called me in the meeting tried to get that.

DR. POWERS: They're doing a good job of making you look good is what you're saying.

MR. REYES: Yeah. And we want to keep it that way.

[Laughter.]

DR. POWERS: Let me ask you a question a little bit philosophically. Just the point you made, you know, you have these findings come out of Phase 2 and they go into Phase 3 and maybe we'll get a change in color. Are you very concerned about that? I mean it doesn't -- somehow it just doesn't bother me very much, because I kind of expect things to change colors, especially on the front end of things, but maybe you have more experience on that.

MR. REYES: My experience is not like the other regions', so I'll speak from my experience.

We have a small number of situations where the color changed, and they all have been in the yellow and white zone. So the outside, the concerns with the public perception that you go to red, and then you go to white, and those kinds of things, we haven't experienced that.

In the cases that we have gone to a regulatory conference to try to discuss one of those, we ahead of time know that the answer is going to be based on which assumptions and which areas are being debated, and I personally don't have a concern in having a small number of the situations have to be changed because of final --

DR. POWERS: If you feel like you're coming into these conferences with a good understanding of how it's going, it could go either way especially when you're close, I mean I think it can change color all it wants to. That's what I wanted to hear.

MR. REYES: And we see more and more lately, and I think we're just better at it, both the licensee and us, more and more agreement up front and deciding we won't go to the meeting, there's nothing else to do, we agree on the color of the risk significance, and so we see more and more of that. I think it's going to get better.

MR. PLISCO: We have an example coming when George talks on Harris. We just had a reg conference a couple weeks ago. They agreed with the violation, they agreed with where we were, and that wasn't even a point of discussion. They just wanted to tell us what they did for corrective action.

DR. POWERS: Yeah, and as the process matures swings are not going to be so wide.

MR. REYES: Other regions don't have the same experience, they have had relatively significant variations on all that.

MR. ROSEN: I think Region III has had some. I think we were told that yesterday at Watts Bar, they did a study.

MR. REYES: Yeah.

MR. MALLETT: But part of that is what we talked about earlier, this change we're trying to incorporate is how much time do you spend, how much effort do you use. You have to be careful that you don't trim it too short that all your answers are going to change.

DR. POWERS: I mean I really like where you're coming from. You're saying if I understand specific colors really don't matter, and as long as I understand where I am I think that's far more important.

MR. LANDIS: The next was a white finding at Surrey, and in April of 2000 the Number 3 EDG lubricating oil silver concentration began to increase indicating that the piston pin bearing surface had excessive wear -- well, that it was having wear. They didn't know that it was excessive until later.

After successfully completing monthly two-hour full-load surveillance runs in April of 2001 the Number 3 EDG was inspected, and the piston pin bearing surfaces were found severely degraded in seven of the twenty pistons.

Now, in March of 2000 just prior to April here they had switched in all three EDGs, and for a two-unit facility they've got three EDGs, Number 3 is the swing EDG, and they had switched the engine oil from an Amoco oil product to a Chevron oil product, and when they did that they didn't know, and the industry was not informed that there was modification in the chemistry to remove a chlorinated compound that would allow it to be more cohesive to the metal, to stay on there longer.

The reason it was removed was more for hazardous waste reasons. So they didn't understand that impact, and so right after that silver concentration began to increase, and there is a normal increase in silver concentration as normal wear occurs.

The vendor had indicated that they could go up to 1 ppm of silver concentrate --

MR. ROSEN: Which vendor was that, by the way?

MR. LANDIS: This was --

MR. ROSEN: This was which diesel manufacturer? I assume that's what you meant by that.

MR. LANDIS: Yes. It's the diesel, and Fairbanks.

MR. MALLETT: General Motors, wasn't it.

MR. LANDIS: No, no. EMB. We were comparing two different -- Fairbanks Morris is at North Anna, and EMD is at Surrey, and we were trying to compare the two all along, so it's EMD these were.

MR. REYES: Correct.

MR. LANDIS: Now, the vendor recommended that they only had to watch it above 1 ppm, so above 2 ppm silver they needed to take some action, but it wasn't imperative, it wasn't an urgent thing you had to shut down the diesel.

Well, they did, they reached above 2 ppm late in 2000, and in the next few oil samples in early 2001 it confirmed that it was above 2 ppm.

So they took it down, and took a look at it, and it was pretty devastating damage to the piston wrist pins area. It had --

DR. BONACA: What about the other diesels?

MR. LANDIS: The other diesels, they then went in and checked those, and there was some minor damage on one of them, a little wear on the other, so it was a common mode issue and that f factored into the PRA calculations.

They ended up replacing all 20 power packs in all three diesels, and changed out the oil to a different oil.

As it turns out, that oil, the new oil doesn't have the chlorinated compound either, but they think that it will have better cohesion characteristics.

DR. BONACA: So the change risk was very small, but what if they had run those three diesels for an extended period of time?

MR. LANDIS: That's where -- you're getting to the very point that was the difference in the calculation. We issued a yellow finding, a preliminary yellow finding, and that was based upon the fact that the diesel f considered, Number 3 was considered not to be able to carry out its intended safety function for the full 24-hour mission time. And there was really no disagreement with the licensee on how that calculation was arrived at.

Then very late in the game just prior to the regulatory conference they proposed taking advantage of -- total probability is the sum of the probability of initiating event of loss of off-site power for less than two hours plus the probability of core damage for initiating events where the loss of off-site power lasts for longer than two hours.

Now, the reason for the two hours was every month they had been testing these diesels and, frankly, we were absolutely amazed that the amount of damage that was on Number 3 EDG it had just passed a surveillance and ran full load for two hours. So when they --

MR. REYES: The length of the mission was the only question, could you survive --

MR. LANDIS: They separated the 24 hours into two hours, and then the remaining 22, and so they took advantage of the fact that there are much lower number of loss of off-site power events where you cannot recover in a two-hour time frame. And that ended up lowering it down to a white finding, and we concurred in that.

MR. ROSEN: This process is so much more robust than what we used to do, and we actually get down to talking about the real type of issues, in that sense it's much more robust.

MR. REYES: Instead of the amount of money of a penalty in the meeting you talk about --

MR. ROSEN: You talk about this. This is the way it should be done.

MR. LANDIS: And we clearly agreed with them that this calculation more accurately reflected the real core damage problem.

MR. MALLETT: And because they didn't want to get into this it also forced them to look at how do they change their detection methods, change the threshold look so they don't get into this risk issue in the future, which is the right thing to do.

MR. ROSEN: Your point about the consequences of managing risk rather than managing indicators, it may look like they're managing indicators, but if you pick the indicators they right they're managing risk.

MR. REYES: Now the old analysis and the fresh ones are different.

MR. ROSEN: Right.

DR. RANSOM: A curious point on that, though. You would think that there are applications where these diesels were running constantly and there would be experience with oils, and so why did they change an oil like that without verification that an oil change for that kind of oil would be satisfactory?

MR. LANDIS: All of them it turned out were independent, all of these oils, all three, and they changed to a Mobil oil after this. All three of them were recommended by all the vendors, and were determined that they were okay. It just turns out that the EMD because it doesn't have forced-flow oil at the start is a little more critical to oil cohering to the bearing surfaces.